



May 20, 2016

Via U.S. Priority Mail

Amy Lueders
State Director
U.S. Bureau of Land Management
New Mexico State Office
301 Dinosaur Trail
Santa Fe, NM 87509

Re: Protest of July 2016 Competitive Oil and Gas Lease Sale

Dear Ms. Lueders:

Pursuant to 43 C.F.R. § 3120.1-3, WildEarth Guardians hereby protests the Bureau of Land Management's ("BLM's") proposal to offer 36 publicly owned oil and gas lease parcels covering 13,876.08 acres of New Mexico public lands land for competitive sale on July 20, 2016. The 36 parcels are located in the Carlsbad Field Office of southeastern New Mexico. The lease parcels included for sale and that we are protesting include the following, as identified by the BLM's in its Final July 2016 Oil and Gas Sale List:¹

Lease Parcel Number	Acres	Field Office	County
NM-201607-001	871.84	Carlsbad	Eddy
NM-201607-002	79.92	Carlsbad	Eddy
NM-201607-003	160.00	Carlsbad	Eddy
NM-201607-004	40.00	Carlsbad	Eddy
NM-201607-005	39.84	Carlsbad	Eddy
NM-201607-006	40.00	Carlsbad	Eddy
NM-201607-007	40.00	Carlsbad	Lea
NM-201607-008	160.00	Carlsbad	Lea
NM-201607-009	320.00	Carlsbad	Lea
NM-201607-010	120.00	Carlsbad	Lea
NM-201607-011	120.00	Carlsbad	Lea

¹ This list of lease parcels is available on the BLM's website at http://www.blm.gov/style/medialib/blm/nm/programs/0/og_sale_notices_and/2016/july_2016.Par.97830.File.dat/July%202016%20OG%20Lease%20Sale%20Notice.pdf.

NM-201607-012	120.00	Carlsbad	Lea
NM-201607-013	160.00	Carlsbad	Lea
NM-201607-014	40.00	Carlsbad	Lea
NM-201607-015	2160.08	Carlsbad	Lea
NM-201607-016	160.00	Carlsbad	Lea
NM-201607-017	280.00	Carlsbad	Lea
NM-201607-018	799.20	Carlsbad	Lea
NM-201607-019	40.00	Carlsbad	Lea
NM-201607-020	160.00	Carlsbad	Lea
NM-201607-021	120.00	Carlsbad	Lea
NM-201607-022	481.240	Carlsbad	Lea
NM-201607-023	960.00	Carlsbad	Lea
NM-201607-024	640.00	Carlsbad	Lea
NM-201607-025	1280.00	Carlsbad	Lea
NM-201607-026	840.00	Carlsbad	Lea
NM-201607-027	840.00	Carlsbad	Lea
NM-201607-028	480.84	Carlsbad	Lea
NM-201607-029	40.00	Carlsbad	Lea
NM-201607-030	371.20	Carlsbad	Lea
NM-201607-031	880.00	Carlsbad	Lea
NM-201607-032	40.00	Carlsbad	Lea
NM-201607-033	120.00	Carlsbad	Lea
NM-201607-034	80.00	Carlsbad	Lea
NM-201607-035	275.80	Carlsbad	Lea
NM-201607-036	516.12	Carlsbad	Lea

In support of its proposed leasing, the agency prepared an Environmental Assessment (“EA”), DOI-BLM-NM-P020-2016-0588-EA.

As will be explained, the BLM’s proposal to lease falls short of ensuring compliance with applicable environmental protection laws and is not based on sufficient analysis and assessment of key environmental impacts under the National Environmental Policy Act (“NEPA”), 42 U.S.C. § 4331, *et seq.* The BLM failed to analyze and assess the reasonably foreseeable greenhouse gas emissions that would result from development of the proposed leases, as well as failed to assess the significance of the climate impacts of these greenhouse gas emissions using the social cost of carbon protocol. The agency’s EA is therefore deficient and fails to provide sufficient justification for its proposed action and its proposal to issue a Finding of No Significant Impact (“FONSI”). For the reasons below, we request the BLM refrain from offering the 36 proposed lease parcels for sale and issuance.

STATEMENT OF INTEREST

WildEarth Guardians is a nonprofit environmental advocacy organization dedicated to protecting the wildlife, wild places, wild rivers, and health of the American West. On behalf of our members, Guardians has an interest in ensuring the BLM fully protects public lands and resources as it conveys the right for the oil and gas industry to develop publicly owned minerals.

More specifically, Guardians has an interest in ensuring the BLM meaningfully and genuinely takes into account the climate implications of its oil and gas leasing decisions and objectively and robustly weighs the costs and benefits of authorizing the release of more greenhouse gas emissions that are known to contribute to global warming.

The mailing address for WildEarth Guardians to which correspondence regarding this protest should be directed is as follows:

WildEarth Guardians
2590 Walnut St.
Denver, CO 80205

STATEMENT OF REASONS

WildEarth Guardians protests the BLM's July 2016 oil and gas lease sale over the agency's failure to adequately analyze and assess the climate impacts of the reasonably foreseeable oil and gas development that will result in accordance with the National Environmental Policy Act ("NEPA"), 42 U.S.C. § 4331, *et seq.*, and regulations promulgated thereunder by the White House Council on Environmental Quality ("CEQ"), 40 C.F.R. § 1500, *et seq.*

NEPA is our "basic national charter for protection of the environment." 40 C.F.R. § 1500.1(a). The law requires federal agencies to fully consider the environmental implications of their actions, taking into account "high quality" information, "accurate scientific analysis," "expert agency comments," and "public scrutiny," prior to making decisions. *Id.* at 1500.1(b). This consideration is meant to "foster excellent action," meaning decisions that are well informed and that "protect, restore, and enhance the environment." *Id.* at 1500.1(c).

To fulfill the goals of NEPA, federal agencies are required to analyze the "effects," or impacts, of their actions to the human environment prior to undertaking their actions. 40 C.F.R. § 1502.16(d). To this end, the agency must analyze the "direct," "indirect," and "cumulative" effects of its actions, and assess their significance. 40 C.F.R. §§ 1502.16(a), (b), and (d). Direct effects include all impacts that are "caused by the action and occur at the same time and place." 40 C.F.R. § 1508.8(a). Indirect effects are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." *Id.* at § 1508.8(b). Cumulative effects include the impacts of all past, present, and reasonably foreseeable actions, regardless of what entity or entities undertake the actions. 40 C.F.R. § 1508.7.

An agency may prepare an environmental assessment ("EA") to analyze the effects of its actions and assess the significance of impacts. *See* 40 C.F.R. § 1508.9; *see also* 43 C.F.R. § 46.300. Where effects are significant, an Environmental Impact Statement ("EIS") must be prepared. *See* 40 C.F.R. § 1502.3. Where significant impacts are not significant, an agency may issue a FONSI and implement its action. *See* 40 C.F.R. § 1508.13; *see also* 43 C.F.R. § 46.325(2).

Here, the BLM fell short of complying with NEPA with regards to analyzing and assessing the potentially significant climate impacts of oil and gas leasing. In support of its proposed leasing, the agency prepared an EA. In the EA, however, the BLM failed to analyze the reasonably foreseeable greenhouse gas emissions that would result from selling the oil and gas lease parcels, as well as failed to assess the significance of any emissions, particularly in terms of carbon costs.

Below, we detail how BLM's proposal fails to comply with NEPA.

1. The BLM Failed to Fully Analyze and Assess the Direct, Indirect, and Cumulative Impacts of Greenhouse Gas Emissions that Would Result from Issuing the Proposed Lease Parcels

In the EA, the BLM did take some steps to analyze and assess some of the reasonably foreseeable greenhouse gas emissions, although as the agency admits, its analysis is "rather simplistic" and "not precise." EA 38. The BLM estimated that on a per well basis, 46 metric tons of carbon dioxide equivalent ("CO₂e") would be emitted, leading to total emissions of 18,795 metric tons annually from a maximum of 401 wells. *See* EA at 39. This estimate is not only simplistic, it's plain wrong.

The agency estimated total greenhouse gas emissions taking a presumed estimate of emissions attributed to production from federal oil and gas leases in Chavez, Eddy, and Lea Counties (583,203 metric tons per year), and dividing that by the total number of wells tapping federal leases (12,443). The BLM apparently reached this estimate by first starting with total oil and gas production emissions reported by the U.S. Environmental Protection Agency, then analyzed more local emissions based on production percentages. So, given that oil production from federal leases in the Permian represents "1.80[%]" of all U.S. oil production, the BLM reasoned that total greenhouse gas emissions from oil production would represent 1.8% of all U.S. greenhouse gases attributable to oil production.

This method may be simplistic, but even its simplicity rests on accurate data inputs. In this case, it appears that BLM relied upon erroneous emissions inventory information to estimate potential emissions, starting with its estimate of total U.S. greenhouse gas emissions. In the EA, the BLM discloses total CO₂e emissions from oil production and natural gas production in the U.S. *See* EA at 38. Yet these reported emissions overall appear to be more than 50% lower than actual emissions disclosed by the EPA in its most recent U.S. greenhouse gas inventory report. For example, while BLM reports total CO₂e emissions from oil production in the U.S. to be 31,300,000 metric tons, the EPA's most recent inventory discloses 68,000,000 metric tons. *See* Exhibit 1, Chapter 3 Excerpt, EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2014," EPA-430-R-16-002 (April 15, 2016) at 3-59—3-60. Further, while BLM reports total CO₂e emissions from natural gas production in the U.S. to be 64,200,000 metric tons, the EPA's most recent inventory discloses 127,600,000 metric tons. *See* Exhibit 1 at 3-69—3-70. As the tables below illustrate, total oil and gas production emissions are actually 195,600,000 metric tons, whereas BLM's estimate of total emissions is 95,500,000 metric tons, more than 100 million tons lower.

U.S. Greenhouse Gas Emissions from Oil Production²

Greenhouse Gas	Total Metric Tons CO ₂ e	Total Reported in EA
Carbon Dioxide, CO ₂	600,000	300,000
Methane, CH ₄	67,400,000	31,000,000
TOTAL	68,000,000	31,300,000

U.S. Greenhouse Gas Emissions from Gas Production³

Greenhouse Gas	Total Metric Tons CO ₂ e	Total Reported in EA
Carbon Dioxide, CO ₂	18,600,000	10,800,000
Methane, CH ₄	109,000,000	53,400,000
TOTAL	127,600,000	64,200,000

This discrepancy taints the rest of the BLM's analysis. Based on total U.S. oil and gas production emissions, the agency estimated that total emissions in the Permian Basin would amount to 582,660 metric tons (presumably the BLM estimated these emissions would come from federal leases in the Permian Basin). However, based on the BLM's own methods and EPA's actual inventory data, emissions would amount to nearly 1.6 million metric tons. Below, we largely recreated the BLM's table from page 38 of the EA. Overall, BLM's estimates are more than 50% lower.

Greenhouse Gas Emissions Using BLM Methodology and Most Recent EPA Greenhouse Gas Inventory Data⁴

	Oil		Gas		Total Oil and Gas Production Emissions (metric tons)
Metric Tons CO ₂ e	CO ₂	CH ₄	CO ₂	CH ₄	
United States	600,000	67,400,000	18,600,000	109,000,000	195,600,000
New Mexico	21,600	2,426,400	892,800	5,232,000	8,572,800
Federal Leases in New Mexico	10,800	1,213,200	688,200	4,033,000	5,945,200
Permian Basin	10,800	1,213,200	51,688	302,903	1,578,591

² "Oil Production" refers to emissions from "Production Field Operations" as disclosed by the EPA.

³ "Gas Production" refers to emissions from natural gas "Field Production" as disclosed by the EPA.

⁴ This table was completed taking the production percentages reported by the BLM on page 37 of the EA and multiplying them by the respective U.S. greenhouse gas data. In the table in the EA, the BLM mistakenly discloses that total Permian Basin gas production constitutes 0.03% of all U.S. gas production. It is actually 0.3%.

BLM then apparently estimated per well emissions in Chavez, Eddy, and Lea Counties by taking the total amount of Permian Basin emissions and dividing it by the number of active, new, and temporarily abandoned wells. *See* EA at 39. Although the BLM discloses in the EA that the total number of wells is 11,216, the agency apparently used an estimate of 12,443 for its calculation and determined a per well estimate of 46.87 metric tons per well. Based on an estimate of 1,578,591 tons, the actual per well estimate should be 126.87 metric tons. With a potential for 401 wells to be developed, this yields an estimate of 50,873 metric tons of CO₂e far higher than the BLM’s estimate of 18,795 metric tons. *See* EA at 39.

Coupled with the fact that the BLM itself acknowledges its estimates of greenhouse gases fail to account for emissions from other reasonably foreseeable activities, including “truck traffic, pumping jack engines, compressor engines, and drill rig engines” (*see* EA at 38), as well fail to account for downstream combustion of oil and gas, this reflects a wholly inadequate disclosure under NEPA. The failure of the agency to come up with a remotely accurate estimate of emissions clearly fails to demonstrate that there will be no significant impacts.

The failure to come up with accurate and comprehensive estimates is not for lack of methodologies. The BLM has been able to estimate per well greenhouse gases based on a consideration of emissions from pump jacks, drilling rigs, truck traffic, processing, compressor engines, and other sources directly related to the construction and production of wells. In a 2013 report prepared for the BLM by Kleinfelder, the agency was able to estimate per well emissions for many major oil and gas producing regions in the western U.S., including the San Juan Basin of New Mexico, the Green River Basin of Wyoming, and others. *See* Exhibit 2, Kleinfelder, “Air Emissions Inventory Estimates for a Representative Oil and Gas Well in the Western United States,” Report Prepared for Bureau of Land Management (March 25, 2013). This report estimated total per well greenhouse gas emission to range from a low of 791 tons (717.6 metric tons) per year for San Juan Basin coalbed methane wells, to a high of 3,682 tons (3,340.3 metric tons) for oil wells in North Dakota. *See* Table below. In either case, the estimates are far greater than the 46.87 metric tons per well per year proffered in the EA.

**Per Well Greenhouse Gas Emission Estimates by Major Western U.S.
Oil and Gas Producing Region. *See* Exhibit 2 at 2.**

Region (Type)	Total CO₂	Total CH₄	Total CO₂e
San Juan, NM (gas)	651.9	6.1	791
Denver, CO (oil)	1,049.0	1.8	1,099
Upper Green River, WY (gas)	2,882.1	14.1	3,194
Willison, ND (oil)	3,156.4	16.6	3,682
Uinta/Piceance (gas)	2,552.1	12.2	2,825

Furthermore, other BLM Field Offices have been able to come up with more accurate estimates of greenhouse gas emissions associated with leasing. In the Royal Gorge Field Office of Colorado, the BLM contracted with URS Group Inc. to prepare an analysis of air emissions from the development of seven oil and gas lease parcels. *See* Exhibit 3, URS Group Inc., “Draft Oil and Gas Air Emissions Inventory Report for Seven Lease Parcels in the BLM Royal Gorge Field Office,” Prepared for BLM, Colorado State Office and Royal Gorge Field Office (July 2013). This report estimated emissions of carbon dioxide and methane on a per well basis and

estimated the total number of wells that could be developed in these seven parcels. *See* Exhibit 3 at 3 and 5. This report was later supplanted by the Colorado Air Resource Management Modeling Study, or CARMMS, which estimated reasonably foreseeable emissions of greenhouse gases, criteria pollutants, and hazardous air pollutants associated with oil and gas development throughout Colorado, as well as part of New Mexico, and modeled air quality impacts. *See* Exhibit 4, ENVIRON, “Colorado Air Resource Management Modeling Study (CARMMS) 2021 Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios,” Prepared for BLM Colorado State Office (January 2015), available online at http://www.blm.gov/style/medialib/blm/co/information/nepa/air_quality.Par.97516.File.dat/CARMMS_Final_Report_w-appendices_012015.pdf. As part of the CARMMS report, the BLM estimated annual per well emissions, including greenhouse gas emissions, as follows:

Phase	PM ₁₀	PM _{2.5}	VOC	CO	NO _x	SO ₂	CO ₂	CH ₄	N ₂ O	HAP
Conventional Construction	5.21	0.64	0.05	0.23	0.72	0.02	108.1	0.00	0.00	0.01
CBM Construction	3.37	0.44	0.03	0.12	0.36	0.01	56.58	4.06	0.00	0.00
Conventional Production	1.15	0.15	6.67	1.30	0.73	0.00	251.9	17.14	0.00	0.43
CBM Production	2.25	0.25	13.10	1.13	0.62	0.00	181.6	19.05	0.00	1.31

It is notable that, based on this estimate, total CO₂ emissions associated with construction and production of conventional (rather than “CBM” or coalbed methane) wells, could be as much as 360 tons per year. Taking into account methane, which the EPA assumes has 25 times the heat trapping capability, or global warming potential, of CO₂, total greenhouse gas emissions are estimated to be 788.5 tons per year.

These other greenhouse gas estimates clearly underscore that the BLM’s estimate of 46.87 tons of emissions per well per year is not just a simplistic estimate, but a wildly inaccurate and misleading figure. What’s more, these other estimates indicate the BLM was more than capable of preparing an accurate estimate of per well emissions. The failure to do so renders the EA inadequate and would undermine the validity of any FONSI.

With regards to greenhouse gases produced from the ultimate consumption of oil and gas that will be produced from the proposed leases, these emissions are similarly not speculative, nor are they impossible to analyze. A recent report prepared by EcoShift Consulting actually quantified the likely greenhouse gas emissions that could result from the production of federal oil and natural gas. *See* Exhibit 5, EcoShift Consulting, “The Potential Greenhouse Gas Emissions of U.S. Federal Fossil Fuels,” report prepared for Center for Biological Diversity and Friends of the Earth (Aug. 2015), available at <http://www.ecoshiftconsulting.com/wp-content/uploads/Potential-Greenhouse-Gas-Emissions-U-S-Federal-Fossil-Fuels.pdf>. This report estimated emissions resulting from refining, processing, transportation, and distribution of oil and gas, even quantifying potential emissions based on the likely end-use of oil and natural gas. There are also estimates by the EPA as to how much CO₂e is produced per barrel of oil consumed and per therm of natural gas consumed. *See* EPA, “Calculations and References,”

website available at <http://www.epa.gov/cleanenergy/energy-resources/refs.html>. According to the EPA, 0.43 metric tons of CO₂ is released per barrel of oil consumed and 0.005302 metric tons of CO₂ is released per therm of natural gas consumed.⁵

Although the BLM may claim that it is speculative to estimate the amount of oil and gas likely to be produced from the proposed leases, this assertion is belied by the fact that the leases are in areas that are already extensively leased and already producing oil and gas. One of the leases, NM-201607-021, would actually become a part of the Arena Roja Federal Unit, clearly indicating oil and gas reserves will be produced from this lease if it is sold. Furthermore, as part of its Resource Management Plan revision process, the BLM developed a new Reasonably Foreseeable Development Scenario for the Pecos District Office of New Mexico, which estimates likely oil and gas reserves to be developed in Chavez, Eddy, and Lea Counties. *See* Engler, T.W., R. Balch, and M. Cather, “Reasonably Foreseeable Development Scenario for the B.L.M. New Mexico Pecos District,” Final Report Submitted to BLM (2015), available online at http://www.blm.gov/style/medialib/blm/nm/field_offices/carlsbad/rmp/documents/Par_79871.File.dat/Final_Report-BLM-NMT-RFD.pdf. At the least, this information should allow the BLM to prepare a “simple” analysis. As it stands, no analysis was completed.

Furthermore, the EA fails to account for greenhouse gas emissions from cumulative and similar actions. As NEPA requires, an agency must analyze the impacts of “similar” and “cumulative” actions in the same NEPA document in order to adequately disclose impacts in an EIS or provide sufficient justification for a FONSI in an EA. *See* 40 C.F.R. §§ 1508.25(a)(2) and (3). Here, the BLM failed to take into account the greenhouse gas emissions resulting from other proposed oil and gas leasing in the New Mexico State Office (including New Mexico, Texas, Oklahoma, and Kansas), as well as related oil and gas development, and to analyze the impacts of these actions in terms of their direct, indirect, and cumulative greenhouse gas emissions.

The need to take into account “similar” and “cumulative” actions is underscored by the fact that the BLM acknowledges that the proper geographic area for analyzing and assessing the impacts of greenhouse gas emissions is on a national scale. The EA in fact assesses greenhouse gas emissions from the proposed leasing in the context of both statewide and national greenhouse gas emissions. *See* EA at 39. Although this assessment was apparently prepared to try to mislead the public into believing that emissions from the proposed leasing are not significant, it actually emphasizes the need for the BLM to not simply account for emissions from the proposed leasing, but likely for all greenhouse gas emissions associated with BLM-approved oil and gas leasing nationwide. Indeed, the BLM cannot claim that emissions are insignificant in the context of state or national emissions, but then fail to disclose the direct, indirect, and cumulative greenhouse gases that would result from all other “similar” and “cumulative” actions within a statewide or national scope. The failure to do so renders the EA inadequate and fails to provide support for a FONSI.

The failure to fully analyze and assess reasonably foreseeable greenhouse gas emissions is made worse by the fact that the underlying Final EIS prepared for the Carlsbad Field Office’s

⁵ According to the U.S. Energy Information Administration (“EIA”), one Mcf of natural gas generally equals 10.28 therms. *See* EIA, “Frequently Asked Questions,” website available at <http://www.eia.gov/tools/faqs/faq.cfm?id=45&t=8>.

Resource Management Plan nowhere analyze or assess greenhouse gas emissions associated with oil and gas development. In fact, when the Resource Management Plan was last amended in 1997, there was no mention of greenhouse gas emissions or climate change. In light of this, the BLM clearly has no basis to conclude that greenhouse gas emissions resulting from the reasonably foreseeable impacts of oil and gas development associated with the proposed leasing would not be significant. Without any analysis of cumulative greenhouse emissions whatsoever, the agency's proposed FONSI is unsupported under NEPA.

2. The BLM Failed to Analyze the Costs of Reasonably Foreseeable Carbon Emissions Using Well-Accepted, Valid, Credible, GAO-Endorsed, Interagency Methods for Assessing Carbon Costs that are Supported by the White House

Compounding the failure of the BLM to accurately estimate the greenhouse gas emissions that would result from reasonably foreseeable oil and gas development is that the agency also rejected analyzing and assessing these emissions in the context of their costs to society. It is particularly disconcerting that the agency refused to analyze and assess costs using the social cost of carbon protocol, a valid, well-accepted, credible, and interagency endorsed method of calculating the costs of greenhouse gas emissions and understanding the potential significance of such emissions.

The social cost of carbon protocol for assessing climate impacts is a method for “estimat[ing] the economic damages associated with a small increase in carbon dioxide (CO₂) emissions, conventionally one metric ton, in a given year [and] represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO₂ reduction).” *See* Exhibit 6, EPA, “Fact Sheet: Social Cost of Carbon” (Nov. 2013) at 1, available online at <http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf>. The protocol was developed by a working group consisting of several federal agencies, including the U.S. Department of Agriculture, EPA, CEQ, and others.

In 2009, an Interagency Working Group was formed to develop the protocol and issued final estimates of carbon costs in 2010. *See* Interagency Working Group on Social Cost of Carbon, “Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866” (Feb. 2010), available online at <https://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf>. These estimates were then revised in 2013 by the Interagency Working Group, which at the time consisted of 13 agencies. *See* Exhibit 7, Interagency Working Group on Social Cost of Carbon, “Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866” (May 2013), available online at https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf. This report and the social cost of carbon estimates were again revised in 2015. *See* Exhibit 8, Interagency Working Group on Social Cost of Carbon, “Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866” (July 2015), available online at <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf> (last accessed Dec. 15, 2015).

Depending on the discount rate and the year during which the carbon emissions are produced, the Interagency Working Group estimates the cost of carbon emissions, and therefore the benefits of reducing carbon emissions, to range from \$11 to \$220 per metric ton of carbon dioxide. *See* Chart Below. In its most recent update to the Social Cost of Carbon Technical Support Document, the White House’s central estimate was reported to be \$36 per metric ton. *See* Exhibit 9, White House, “Estimating the Benefits from Carbon Dioxide Emissions Reductions,” website available at <https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions>. In July 2014, the U.S. Government Accountability Office (“GAO”) confirmed that the Interagency Working Group’s estimates were based on sound procedures and methodology. *See* Exhibit 10, GAO, “Regulatory Impact Analysis, Development of Social Cost of Carbon Estimates,” GAO-14-663 (July 2014), available online at <http://www.gao.gov/assets/670/665016.pdf>.

Revised Social Cost of CO₂, 2010 – 2050 (in 2007 dollars per metric ton of CO₂)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

Most recent social cost of carbon estimates presented by Interagency Working Group on Social Cost of Carbon. The 95th percentile value is meant to represent “higher-than-expected” impacts from climate change.

Although often utilized in the context of agency rulemakings, the protocol has been recommended for use and has been used in project-level decisions. For instance, the EPA recommended that an EIS prepared by the U.S. Department of State for the proposed Keystone XL oil pipeline include “an estimate of the ‘social cost of carbon’ associated with potential increases of GHG emissions.” Exhibit 11, EPA, Comments on Supplemental Draft EIS for the Keystone XL Oil Pipeline (June 6, 2011).

More importantly, the BLM has also utilized the social cost of carbon protocol in the context of oil and gas approvals. In recent Environmental Assessments for oil and gas leasing in Montana, the agency estimated “the annual SCC [social cost of carbon] associated with potential development on lease sale parcels.” Exhibit 12, BLM, “Environmental Assessment for October 21, 2014 Oil and Gas lease Sale,” DOI-BLM-MT-0010-2014-0011-EA (May 19, 2014) at 76, available online at [http://www.blm.gov/style/medialib/blm/mt/blm_programs/energy/oil_and_gas/leasing/lease_sale/2014/oct_21_2014/july23posting.Par.25990.File.dat/MCFO%20EA%20October%202014%20Sale_Post%20with%20Sale%20\(1\).pdf](http://www.blm.gov/style/medialib/blm/mt/blm_programs/energy/oil_and_gas/leasing/lease_sale/2014/oct_21_2014/july23posting.Par.25990.File.dat/MCFO%20EA%20October%202014%20Sale_Post%20with%20Sale%20(1).pdf). In conducting its analysis, the BLM used a “3 percent average discount rate and year 2020 values,” presuming social costs of carbon to be \$46 per

metric ton. *Id.* Based on its estimate of greenhouse gas emissions, the agency estimated total carbon costs to be “\$38,499 (in 2011 dollars).” *Id.* In Idaho, the BLM also utilized the social cost of carbon protocol to analyze and assess the costs of oil and gas leasing. Using a 3% average discount rate and year 2020 values, the agency estimated the cost of carbon to be \$51 per ton of annual CO₂e increase. *See* Exhibit 13, BLM, “Little Willow Creek Protective Oil and Gas Leasing,” EA No. DOI-BLM-ID-B010-2014-0036-EA (February 10, 2015) at 81, available online at https://www.blm.gov/epl-front-office/projects/nepa/39064/55133/59825/DOI-BLM-ID-B010-2014-0036-EA_UPDATED_02272015.pdf. Based on this estimate, the agency estimated that the total carbon cost of developing 25 wells on five lease parcels to be \$3,689,442 annually. *Id.* at 83.

To be certain, the social cost of carbon protocol presents a conservative estimate of economic damages associated with the environmental impacts climate change. As the EPA has noted, the protocol “does not currently include all important [climate change] damages.” Exhibit 6. As explained:

The models used to develop [social cost of carbon] estimates do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research.

Id. In fact, more recent studies have reported significantly higher carbon costs. For instance, a report published this month found that current estimates for the social cost of carbon should be increased six times for a mid-range value of \$220 per ton. *See* Exhibit 14, Moore, C.F. and B.D. Delvane, “Temperature impacts on economic growth warrant stringent mitigation policy,” *Nature Climate Change* (January 12, 2015) at 2. In spite of uncertainty and likely underestimation of carbon costs, nevertheless, “the SCC is a useful measure to assess the benefits of CO₂ reductions,” and thus a useful measure to assess the costs of CO₂ increases. Exhibit 6.

That the economic impacts of climate change, as reflected by an assessment of social cost of carbon, should be a significant consideration in agency decisionmaking, is emphasized by a recent White House report, which warned that delaying carbon reductions would yield significant economic costs. *See* Exhibit 15, Executive Office of the President of the United States, “The Cost of Delaying Action to Stem Climate Change” (July 2014), available online at https://www.whitehouse.gov/sites/default/files/docs/the_cost_of_delaying_action_to_stem_climate_change.pdf. As the report states:

[D]elaying action to limit the effects of climate change is costly. Because CO₂ accumulates in the atmosphere, delaying action increases CO₂ concentrations. Thus, if a policy delay leads to higher ultimate CO₂ concentrations, that delay produces persistent economic damages that arise from higher temperatures and higher CO₂ concentrations. Alternatively, if a delayed policy still aims to hit a given climate target, such as limiting CO₂ concentration to given level, then that delay means that the policy, when implemented, must be more stringent and thus more costly in subsequent years. In either case, delay is costly.

Id. at 1.

The requirement to analyze the social cost of carbon is supported by the general requirements of NEPA, specifically supported in federal case law, and by Executive Order 13,514. As explained, NEPA requires agencies to analyze the consequences of proposed agency actions and consider include direct, indirect, and cumulative consequences. In terms of oil and gas leasing, an analysis of site-specific impacts must take place at the lease stage and cannot be deferred until after receiving applications to drill. *See New Mexico ex rel. Richardson v. Bureau of Land Management*, 565 F.3d 683, 717-18 (10th Cir. 2009); *Conner v. Burford*, 848 F.2d 1441 (9th Cir.1988); *Bob Marshall Alliance v. Hodel*, 852 F.2d 1223, 1227 (9th Cir.1988).

To this end, courts have ordered agencies to assess the social cost of carbon pollution, even before a federal protocol for such analysis was adopted. In 2008, the U.S. Court of Appeals for the Ninth Circuit ordered the National Highway Traffic Safety Administration to include a monetized benefit for carbon emissions reductions in an Environmental Assessment prepared under NEPA. *Center for Biological Diversity v. National Highway Traffic Safety Administration*, 538 F.3d 1172, 1203 (9th Cir. 2008). The Highway Traffic Safety Administration had proposed a rule setting corporate average fuel economy standards for light trucks. A number of states and public interest groups challenged the rule for, among other things, failing to monetize the benefits that would accrue from a decision that led to lower carbon dioxide emissions. The Administration had monetized the employment and sales impacts of the proposed action. *Id.* at 1199. The agency argued, however, that valuing the costs of carbon emissions was too uncertain. *Id.* at 1200. The court found this argument to be arbitrary and capricious. *Id.* The court noted that while estimates of the value of carbon emissions reductions occupied a wide range of values, the correct value was certainly not zero. *Id.* It further noted that other benefits, while also uncertain, were monetized by the agency. *Id.* at 1202.

More recently, a federal court has done likewise for a federally approved coal lease. That court began its analysis by recognizing that a monetary cost-benefit analysis is not universally required by NEPA. *See High Country Conservation Advocates v. U.S. Forest Service*, 52 F.Supp.3d 1174 (D. Colo. 2014), citing 40 C.F.R. § 1502.23. However, when an agency prepares a cost-benefit analysis, “it cannot be misleading.” *Id.* at 1182 (citations omitted). In that case, the NEPA analysis included a quantification of benefits of the project. However, the quantification of the social cost of carbon, although included in earlier analyses, was omitted in the final NEPA analysis. *Id.* at 1196. The agencies then relied on the stated benefits of the project to justify project approval. This, the court explained, was arbitrary and capricious. *Id.* Such approval was based on a NEPA analysis with misleading economic assumptions, an approach long disallowed by courts throughout the country. *Id.*

A recent op-ed in the New York Times from Michael Greenstone, the former chief economist for the President’s Council of Economic Advisers, confirms that it is appropriate and acceptable to calculate the social cost of carbon when reviewing whether to approve fossil fuel extraction. *See Exhibit 16, Greenstone, M., “There’s a Formula for Deciding When to Extract Fossil Fuels,” New York Times* (Dec. 1, 2015), available online at

http://www.nytimes.com/2015/12/02/upshot/theres-a-formula-for-deciding-when-to-extract-fossil-fuels.html?_r=0.

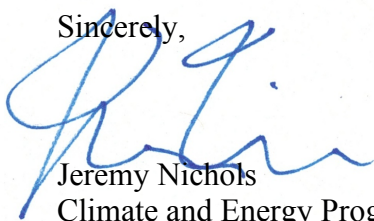
In light of all this, it appears more than reasonable to have expected the BLM to take into account carbon costs as part of its NEPA analyses. The agency did not. Instead, the BLM rejected the notion that analyzing climate impacts was even possible, implicitly concluding that there would be no climate impacts and no climate costs associated with the proposed oil and gas leasing. This renders the EA fatally flawed and unable to support a FONSI.

This is not for lack of the ability to perform a social cost of carbon analysis. Taking the 2016 social cost of carbon figures from the most recent Interagency Working Group Technical Support Document, one can easily estimate the likely climate costs that will result from the reasonably foreseeable carbon emissions from the proposed leasing. Using the refined greenhouse gas estimate of 1,578,591 tons annually, which itself is a low figure given BLM's failure to account for a number of other reasonably foreseeable sources of greenhouse gas emissions, and using discount rates from the most recent Technical Support Document, the climate costs could range from as low as \$17.36 million to as high as \$170.49 million annually. See Table below. The climate costs would actually be much higher if all reasonably foreseeable sources of carbon emissions were considered by the BLM.

Discount Rate (2016)	5.0%	3.0%	2.5%	3.0% (95 th percentile)
SCC Value (\$/ton of CO₂e)	\$11	\$38	\$57	\$108
Total Costs	\$17,364,501	\$59,986,458	\$89,979,687	\$170,487,828

The failure of the BLM to analyze and assess the social cost of carbon indicates that the agency failed to appropriately analyze and assess the climate impacts of the proposed leasing, further undermining any assertion that a FONSI is appropriate.

Sincerely,



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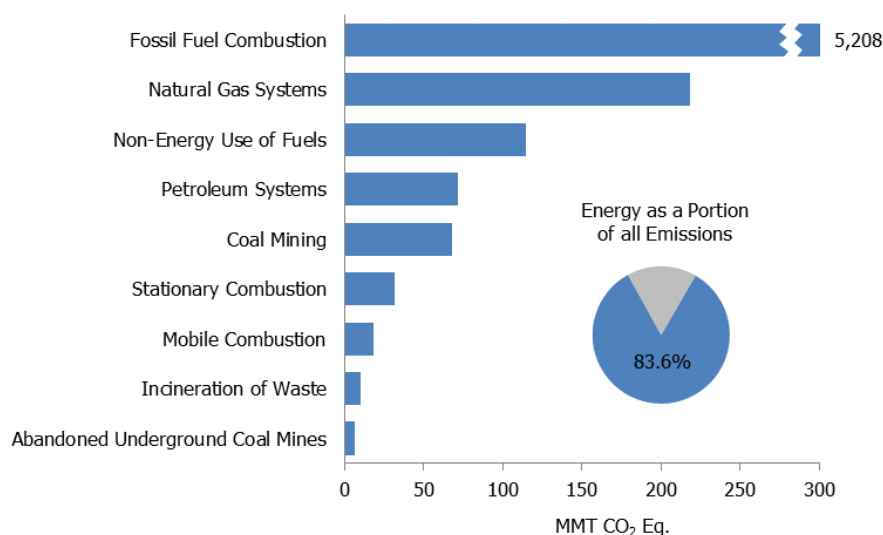
Exhibit 1

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 83.6 percent of total greenhouse gas emissions on a carbon dioxide (CO₂) equivalent basis in 2014.¹ This included 97, 45, and 10 percent of the nation's CO₂, methane (CH₄), and nitrous oxide (N₂O) emissions, respectively. Energy-related CO₂ emissions alone constituted 78.3 percent of national emissions from all sources on a CO₂ equivalent basis, while the non-CO₂ emissions from energy-related activities represented a much smaller portion of total national emissions (5.4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO₂ being the primary gas emitted (see Figure 3-1). Globally, approximately 32,190 million metric tons (MMT) of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2013, of which the United States accounted for approximately 16 percent.² Due to their relative importance, fossil fuel combustion-related CO₂ emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH₄ and N₂O. Stationary combustion of fossil fuels was the second-largest source of N₂O emissions in the United States and mobile fossil fuel combustion was the fourth-largest source.

Figure 3-1: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)



¹ Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

² Global CO₂ emissions from fossil fuel combustion were taken from International Energy Agency *CO₂ Emissions from Fossil Fuels Combustion – Highlights* <<https://www.iea.org/publications/freepublications/publication/CO2EmissionsFromFuelCombustionHighlights2015.pdf>> IEA (2015).

Greenhouse Gas Emissions: Sources and Sinks

Sources (Left Side):

- Domestic Fossil Fuel Production: 4,890
- Fossil Fuel Imports: 1,648
- Coal: 1,891
- Natural Gas: 1,409
- Petroleum: 1,336
- Natural Gas Liquids, Liquefied Refinery Gas, & Other Liquids: 254
- Petroleum: 1,286
- NG: 146
- Coal: 27
- Other: 189

Consumption and Emissions (Middle):

- Apparent Consumption: 5,596
- Fossil Fuel Energy Exports: 817
- Stock Changes: 53
- Non-Energy Use Exports: 138
- International Bunkers: 102
- Industrial Processes: 98
- Atmospheric Emissions: 5,474

Sinks (Right Side):

- NEU Emissions 2
- Coal Emissions: 1,656
- NEU Emissions 6
- Natural Gas Emissions: 1,432
- Combustion Emissions: 1,654
- Combustion Emissions: 1,427
- NEU Emissions 59
- Petroleum Emissions: 2,186
- Combustion Emissions: 2,128
- Non-Energy Use Carbon Sequestered: 205
- Non-Energy Use U.S. Territories: 4
- Balancing Item (84)

Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

Table 3-1: CO₂, CH₄, and N₂O Emissions from Energy (MMT CO₂ Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO₂	4,908.8	5,932.5	5,520.0	5,386.6	5,179.7	5,330.8	5,377.9
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.2
<i>Electricity Generation</i>	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
<i>Transportation</i>	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.6
<i>Industrial</i>	842.5	828.0	775.5	773.3	782.9	812.2	813.3
<i>Residential</i>	338.3	357.8	334.6	326.8	282.5	329.7	345.1
<i>Commercial</i>	217.4	223.5	220.1	220.7	196.7	221.0	231.9
<i>U.S. Territories</i>	27.9	49.9	41.4	41.5	43.6	43.5	41.0
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Natural Gas Systems	37.7	30.1	32.4	35.7	35.2	38.5	42.4
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Petroleum Systems	3.6	3.9	4.2	4.2	3.9	3.7	3.6
<i>Biomass-Wood^a</i>	215.2	206.9	192.5	195.2	194.9	211.6	217.7
<i>International Bunker Fuels^a</i>	103.5	113.1	117.0	111.7	105.8	99.8	103.2
<i>Biomass-Ethanol^a</i>	4.2	22.9	72.6	72.9	72.8	74.7	76.1
CH₄	363.3	307.0	318.5	313.3	312.5	321.2	328.3
Natural Gas Systems	206.8	177.3	166.2	170.1	172.6	175.6	176.1
Petroleum Systems	38.7	48.8	54.1	56.3	58.4	64.7	68.1
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	67.6
Stationary Combustion	8.5	7.4	7.1	7.1	6.6	8.0	8.1
Abandoned Underground Coal							
Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.3
Mobile Combustion	5.6	2.7	2.3	2.2	2.2	2.1	2.0
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^a</i>	0.2	0.1	0.1	0.1	0.1	0.1	0.1

3-2 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014

N₂O	53.6	55.0	46.1	44.0	41.7	41.4	40.0
Stationary Combustion	11.9	20.2	22.2	21.3	21.4	22.9	23.4
Mobile Combustion	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
<i>International Bunker Fuels^a</i>	<i>0.9</i>	<i>1.0</i>	<i>1.0</i>	<i>1.0</i>	<i>0.9</i>	<i>0.9</i>	<i>0.9</i>
Total	5,324.9	6,294.5	5,884.6	5,744.0	5,533.9	5,693.5	5,746.2

+ Does not exceed 0.05 MMT CO₂ Eq.

^a These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO₂, CH₄, and N₂O Emissions from Energy (kt)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO₂	4,908,041	5,932,474	5,519,975	5,386,609	5,179,749	5,330,837	5,377,857
Fossil Fuel Combustion	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,207
Non-Energy Use of Fuels	118,114	138,876	114,063	108,515	105,624	121,682	114,311
Natural Gas Systems	37,732	30,076	32,439	35,662	35,203	38,457	42,351
Incineration of Waste	7,972	12,454	11,026	10,550	10,362	9,421	9,421
Petroleum Systems	3,553	3,927	4,154	4,192	3,876	3,693	3,567
<i>Biomass – Wood^a</i>	<i>215,186</i>	<i>206,901</i>	<i>192,462</i>	<i>195,182</i>	<i>194,903</i>	<i>211,581</i>	<i>217,654</i>
<i>International Bunker Fuels^a</i>	<i>103,463</i>	<i>113,139</i>	<i>116,992</i>	<i>111,660</i>	<i>105,805</i>	<i>99,763</i>	<i>103,201</i>
<i>Biomass – Ethanol^a</i>	<i>4,227</i>	<i>22,943</i>	<i>72,647</i>	<i>72,881</i>	<i>72,827</i>	<i>74,743</i>	<i>76,075</i>
CH₄	14,532	12,281	12,741	12,533	12,498	12,848	13,132
Natural Gas Systems	8,270	7,093	6,647	6,803	6,906	7,023	7,045
Petroleum Systems	1,550	1,953	2,163	2,251	2,335	2,588	2,726
Coal Mining	3,860	2,565	3,293	2,849	2,658	2,584	2,703
Stationary Combustion	339	296	283	283	265	320	324
Abandoned Underground							
Coal Mines	288	264	263	257	249	249	253
Mobile Combustion	226	110	91	90	86	84	82
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^a</i>	<i>7</i>	<i>5</i>	<i>6</i>	<i>5</i>	<i>4</i>	<i>3</i>	<i>3</i>
N₂O	180	185	155	148	140	139	134
Stationary Combustion	40	68	74	71	72	77	79
Mobile Combustion	138	115	79	75	67	61	55
Incineration of Waste	2	1	1	1	1	1	1
<i>International Bunker Fuels^a</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>

+ Does not exceed 0.5 kt

^a These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the United Nations Framework Convention on Climate Change (UNFCCC) requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC). Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement. The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations, but rather, this Inventory presents emissions and sinks in a common format consistent with how countries are to report Inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

Box 3-2: Energy Data from the Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. 40 CFR part 98 requires reporting by 41 industrial categories. Data reporting by affected facilities included the reporting of emissions from fuel combustion at that affected facility. In general, the threshold for reporting is 25,000 metric tons or more of CO₂ Eq. per year.

The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective planned improvements sections for source categories in this chapter, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this Inventory (see, also, Box 3-4). Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. It should be noted that the definitions and provisions for reporting fuel types in EPA's GHGRP may differ from those used in the Inventory in meeting the UNFCCC reporting guidelines. In line with the UNFCCC reporting guidelines, the inventory report is a comprehensive accounting of all emissions from fuel types identified in the IPCC guidelines and provides a separate reporting of emissions from biomass. Further information on the reporting categorizations in EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the GHGRP website.

EPA presents the data collected by its GHGRP through a data publication tool that allows data to be viewed in several formats including maps, tables, charts and graphs for individual facilities or groups of facilities.

3.1 Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO₂, CH₄, and N₂O. Given that CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO₂ emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO₂ from fossil fuel combustion also differ from the estimation of CH₄ and N₂O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (MMT CO₂ Eq.)

Gas	1990	2005	2010	2011	2012	2013	2014
CO ₂	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.2
CH ₄	14.1	10.2	9.3	9.3	8.8	10.1	10.1
N ₂ O	53.1	54.7	45.8	43.8	41.5	41.2	39.8
Total	4,807.9	5,812.0	5,413.4	5,280.8	5,074.9	5,208.8	5,258.1

Note: Totals may not sum due to independent rounding

Table 3-4: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (kt)

Gas	1990	2005	2010	2011	2012	2013	2014
CO ₂	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,207
CH ₄	565	406	372	374	352	404	405
N ₂ O	178	183	154	147	139	138	133

CO₂ from Fossil Fuel Combustion

Carbon dioxide is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO₂ emissions from fossil fuel combustion are presented in Table 3-5. In 2014, CO₂ emissions from fossil fuel combustion increased by 1.0 percent relative to the previous year. The increase in CO₂ emissions from fossil fuel combustion was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes; and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions.⁴ In 2014, CO₂ emissions from fossil fuel combustion were 5,208.2 MMT CO₂ Eq., or 9.9 percent above emissions in 1990 (see Table 3-5).⁵

Table 3-5: CO₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq.)

Fuel/Sector	1990	2005	2010	2011	2012	2013	2014
Coal	1,718.4	2,112.3	1,927.7	1,813.9	1,592.8	1,654.4	1,653.7
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	6.6	5.8	4.1	3.9	4.5
Industrial	155.3	115.3	90.1	82.0	74.1	75.7	75.3
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,983.8	1,827.6	1,722.7	1,511.2	1,571.3	1,570.4
U.S. Territories	0.6	3.0	3.4	3.4	3.4	3.4	3.4
Natural Gas	1,000.3	1,166.7	1,272.1	1,291.5	1,352.6	1,391.2	1,426.6
Residential	238.0	262.2	258.6	254.7	224.8	266.2	277.6
Commercial	142.1	162.9	167.7	170.5	156.9	179.1	189.2
Industrial	408.9	388.5	407.2	417.3	434.8	451.9	466.0
Transportation	36.0	33.1	38.1	38.9	41.3	47.0	47.6
Electricity Generation	175.3	318.8	399.0	408.8	492.2	444.0	443.2
U.S. Territories	NO	1.3	1.5	1.4	2.6	3.0	3.0
Petroleum	2,021.5	2,467.8	2,158.2	2,121.9	2,078.9	2,111.6	2,127.5
Residential	97.4	94.9	76.0	72.2	57.7	63.4	67.5
Commercial	63.3	51.3	45.8	44.5	35.7	38.0	38.2
Industrial	278.3	324.2	278.2	274.0	274.1	284.6	271.9
Transportation	1,457.7	1,854.0	1,690.2	1,668.8	1,655.4	1,666.0	1,690.0
Electricity Generation	97.5	97.9	31.4	25.8	18.3	22.4	25.3
U.S. Territories	27.2	45.6	36.5	36.7	37.6	37.1	34.6
Geothermal^a	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.2

+ Does not exceed 0.05 MMT CO₂ Eq.

NE (Not estimated)

⁴ Further details on industrial sector combustion emissions are provided by EPA's GHGRP
<<http://ghgdata.epa.gov/ghgp/main.do>>.

⁵ An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

NO (Not occurring)

^a Although not technically a fossil fuel, geothermal energy-related CO₂ emissions are included for reporting purposes.

Note: Totals may not sum due to independent rounding.

Trends in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, size of houses, and number of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

Carbon dioxide emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy.

Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.⁶

Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO₂ Emissions and Total 2014 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO₂ Eq. and Percent)

Sector	Fuel Type	2010 to 2011		2011 to 2012		2012 to 2013		2013 to 2014		Total 2014
Electricity Generation	Coal	-104.9	-5.7%	-211.5	-12.3%	60.1	4.0%	-0.9	-0.1%	1,570.4
Electricity Generation	Natural Gas	9.8	2.5%	83.5	20.4%	-48.3	-9.8%	-0.8	-0.2%	443.2
Electricity Generation	Petroleum	-5.6	-17.8%	-7.5	-29.0%	4.1	22.3%	2.9	12.8%	25.3
Transportation ^a	Petroleum	-21.4	-1.3%	-13.3	-0.8%	10.6	0.6%	24.0	1.4%	1,690.0
Residential	Natural Gas	-3.9	-1.5%	-29.8	-11.7%	41.4	18.4%	11.4	4.3%	277.6
Commercial	Natural Gas	2.7	1.6%	-13.6	-8.0%	22.3	14.2%	10.0	5.6%	189.2
Industrial	Coal	-8.1	-9.0%	-7.9	-9.7%	1.7	2.3%	-0.4	-0.6%	75.3
Industrial	Natural Gas	10.1	2.5%	17.5	4.2%	17.1	3.9%	14.2	3.1%	466.0
All Sectors^b	All Fuels^b	-130.6	-2.4%	-203.0	-3.9%	132.9	2.6%	50.6	1.0%	5,208.2

^a Excludes emissions from International Bunker Fuels.

^b Includes fuels and sectors not shown in table.

Note: Totals may not sum due to independent rounding.

In the United States, 82 percent of the energy consumed in 2014 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (10 percent), primarily hydroelectric power, wind energy and biofuels (EIA 2016).⁷ Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 35 percent of total U.S. energy consumption in 2014. Natural gas and coal followed in order of energy demand importance, accounting for approximately 28 percent and 19 percent of total U.S. energy consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2016).

⁶ Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

⁷ Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

Figure 3-3: 2014 U.S. Energy Consumption by Energy Source (Percent)

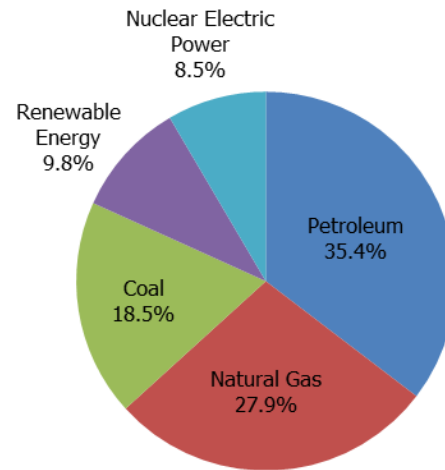


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

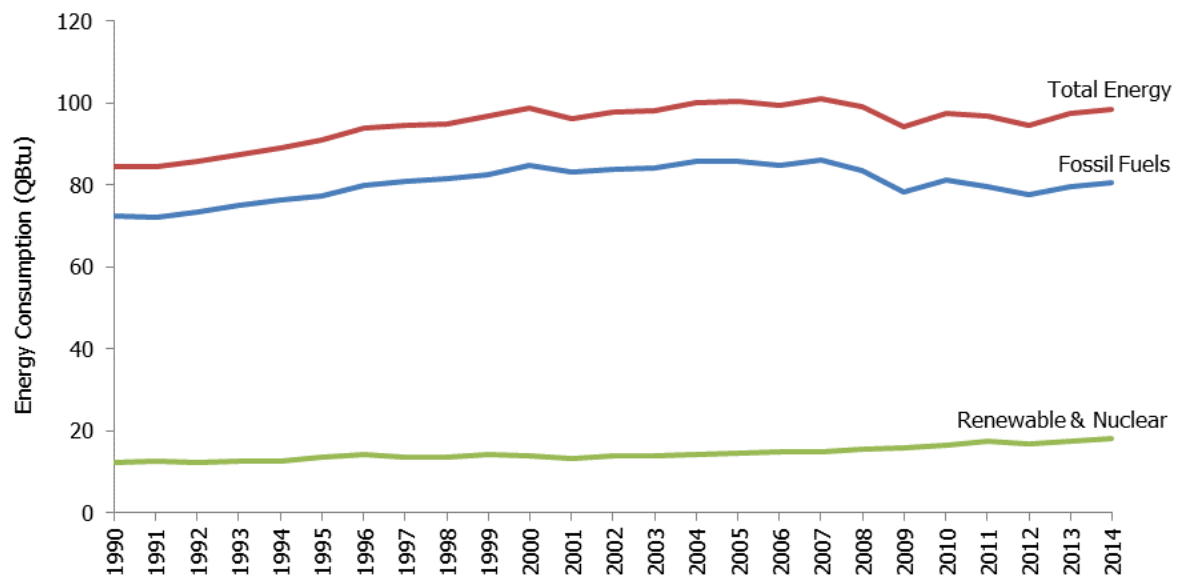
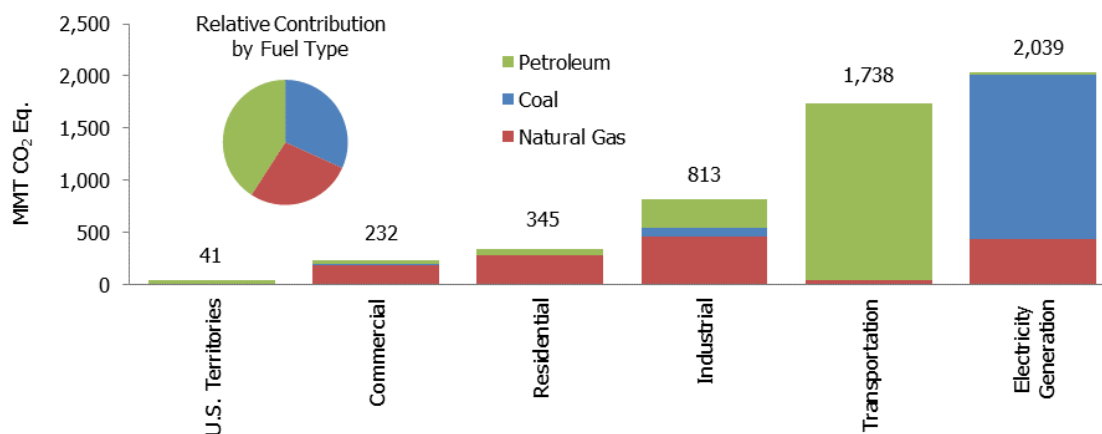


Figure 3-5: 2014 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO₂ Eq.)



Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO₂ and smaller amounts of other gases, including CH₄, CO, and NMVOCs.⁸ These other C containing non-CO₂ gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO₂ in the atmosphere. Therefore, it is assumed all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO₂.

Box 3-3: Weather and Non-Fossil Energy Effects on CO₂ from Fossil Fuel Combustion Trends

In 2014, weather conditions, and a very cold first quarter of the year in particular, caused a significant increase in energy demand for heating fuels and is reflected in the increased residential emissions during the early part of the year (EIA 2016). The United States in 2014 also experienced a cooler winter overall compared to 2013, as heating degree days increased (1.9 percent). Cooling degree days decreased by 0.6 percent and despite this decrease in cooling degree days, electricity demand to cool homes still increased slightly. Colder winter conditions compared to 2013 resulted in a significant increase in the amount of energy required for heating, and heating degree days in the United States were 0.6 percent above normal for the first time since 2003 (see Figure 3-6). Summer conditions were slightly cooler in 2014 compared to 2013, and summer temperatures were warmer than normal, with cooling degree days 6.7 percent above normal (see Figure 3-7) (EIA 2016).⁹

⁸ See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO₂ gas emissions from fossil fuel combustion.

⁹ Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65 degrees Fahrenheit, while cooling degree days are deviations of the mean daily temperature above 65 degrees Fahrenheit. Heating degree days have a considerably greater effect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ± 10 percent and ± 14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2014, Index Normal = 100)

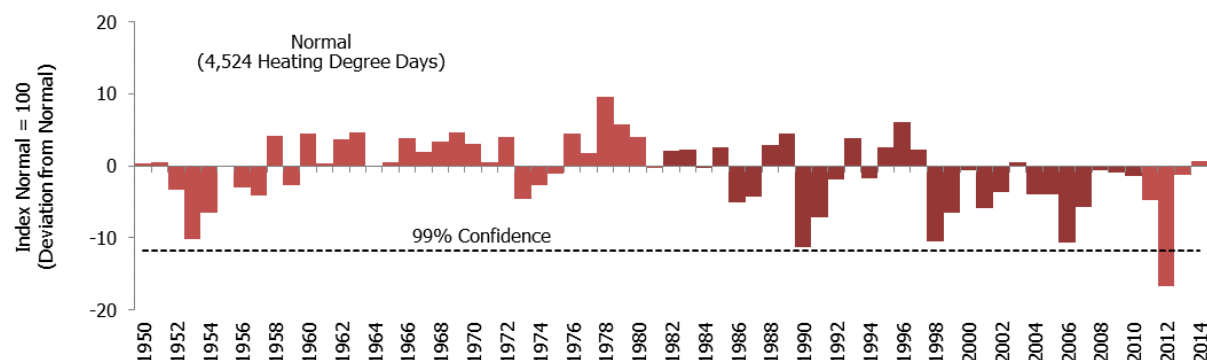
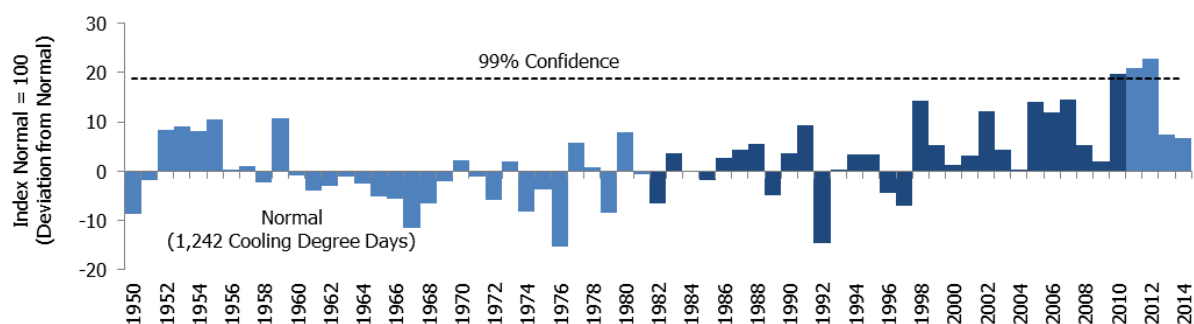


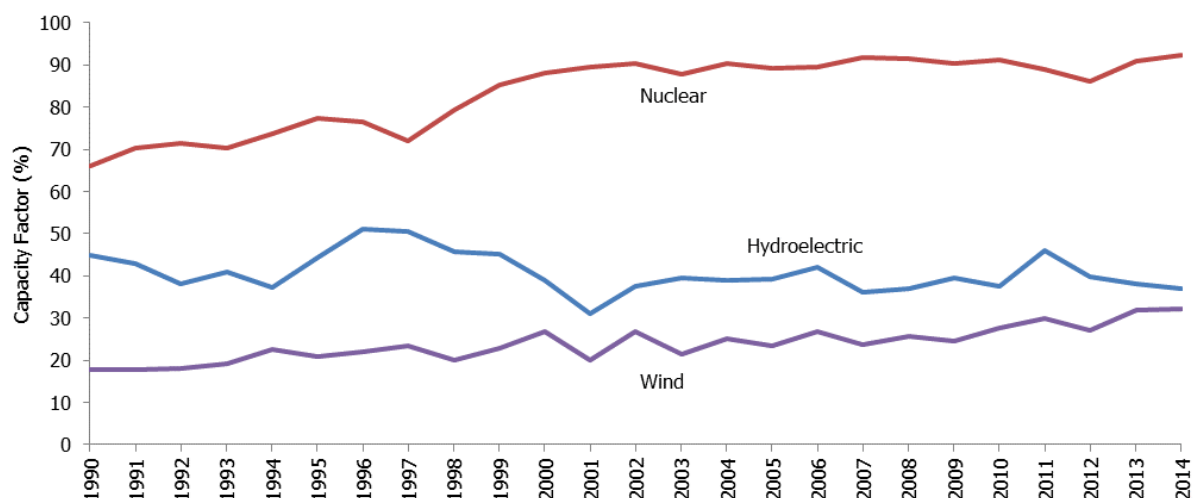
Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2014, Index Normal = 100)



Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors)¹⁰ of existing plants in 2014 remained high at 92 percent. Electricity output by hydroelectric power plants decreased in 2014 by approximately 3 percent. In recent years, the wind power sector has been showing strong growth, such that, on the margin, it is becoming a relatively important electricity source. Electricity generated by nuclear plants in 2014 provided more than 3 times as much of the energy generated in the United States from hydroelectric plants (EIA 2016). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

¹⁰ The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2016).

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2014, Percent)



Fossil Fuel Combustion Emissions by Sector

In addition to the CO₂ emitted from fossil fuel combustion, CH₄ and N₂O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO₂, CH₄, and N₂O emissions from fossil fuel combustion by sector.

Table 3-7: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by Sector (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	1,828.5	2,417.4	2,277.4	2,175.8	2,040.5	2,057.7	2,059.4
CO ₂	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
CH ₄	0.3	0.5	0.5	0.4	0.4	0.4	0.4
N ₂ O	7.4	16.0	18.5	17.6	17.8	19.1	19.6
Transportation	1,540.6	1,924.1	1,754.2	1,732.3	1,718.9	1,733.3	1,756.0
CO ₂	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.6
CH ₄	5.6	2.7	2.3	2.2	2.2	2.1	2.0
N ₂ O	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Industrial	847.4	832.7	779.3	777.3	786.9	816.2	817.2
CO ₂	842.5	828.0	775.5	773.3	782.9	812.2	813.3
CH ₄	1.8	1.7	1.4	1.5	1.5	1.5	1.5
N ₂ O	3.1	2.9	2.4	2.5	2.5	2.4	2.4
Residential	344.6	362.8	339.4	331.7	287.0	335.6	351.1
CO ₂	338.3	357.8	334.6	326.8	282.5	329.7	345.1
CH ₄	5.2	4.1	4.0	4.0	3.7	5.0	5.0
N ₂ O	1.0	0.9	0.8	0.8	0.7	1.0	1.0
Commercial	218.8	224.9	221.5	222.1	197.9	222.4	233.3
CO ₂	217.4	223.5	220.1	220.7	196.7	221.0	231.9
CH ₄	1.0	1.1	1.1	1.0	0.9	1.0	1.1
N ₂ O	0.4	0.3	0.3	0.3	0.3	0.3	0.3

U.S. Territories^a	28.0	50.1	41.6	41.7	43.7	43.7	41.2
Total	4,807.9	5,812.0	5,413.4	5,280.8	5,074.9	5,208.8	5,258.1

^a U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Notes: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O and the indirect greenhouse gases NO_x, CO, and NMVOCs.¹¹ Methane and N₂O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. Nitrous oxide emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO₂, including CH₄, N₂O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N₂O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N₂O from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH₄ content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH₄ and N₂O from transportation.¹² Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data. This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity consumption in that sector. The results of this alternative method are presented in Table 3-8.

Table 3-8: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation	1,543.7	1,928.9	1,758.7	1,736.6	1,722.8	1,737.4	1,760.1
CO ₂	1,496.8	1,891.8	1,732.7	1,711.9	1,700.6	1,717.0	1,741.7
CH ₄	5.6	2.7	2.3	2.2	2.2	2.1	2.0
N ₂ O	41.2	34.4	23.7	22.5	20.1	18.2	16.4
Industrial	1,537.0	1,574.3	1,425.7	1,407.2	1,385.0	1,416.6	1,416.6
CO ₂	1,529.2	1,564.6	1,416.5	1,398.0	1,375.7	1,407.0	1,406.8
CH ₄	2.0	1.9	1.6	1.6	1.6	1.6	1.6
N ₂ O	5.9	7.8	7.6	7.6	7.7	8.0	8.2
Residential	940.2	1,224.9	1,186.5	1,129.0	1,018.8	1,077.6	1,093.6
CO ₂	931.4	1,214.1	1,174.6	1,117.5	1,007.8	1,064.6	1,080.3
CH ₄	5.4	4.2	4.2	4.2	3.9	5.1	5.2
N ₂ O	3.4	6.6	7.7	7.3	7.1	7.9	8.1

¹¹ Sulfur dioxide (SO₂) emissions from stationary combustion are addressed in Annex 6.3.

¹² Separate calculations were performed for transportation-related CH₄ and N₂O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Commercial	759.1	1,033.7	1,000.9	966.3	904.5	933.6	946.7
CO ₂	755.4	1,026.8	993.0	958.8	897.0	925.5	938.4
CH ₄	1.1	1.2	1.2	1.2	1.1	1.2	1.2
N ₂ O	2.5	5.7	6.6	6.3	6.4	6.9	7.1
U.S. Territories^a	28.0	50.1	41.6	41.7	43.7	43.7	41.2
Total	4,807.9	5,812.0	5,413.4	5,280.8	5,074.9	5,208.8	5,258.1

^a U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Notes: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO₂ emissions from fossil fuel combustion by stationary sources. The CO₂ emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section of CO₂ from Fossil Fuel Combustion). Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O. Table 3-10 and Table 3-11 present CH₄ and N₂O emissions from the combustion of fuels in stationary sources.¹³ Methane and N₂O emissions from stationary combustion sources depend upon fuel characteristics, combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. Nitrous oxide emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency. The CH₄ and N₂O emission estimation methodology was revised in 2010 to utilize the facility-specific technology and fuel use data reported to EPA's Acid Rain Program (see Methodology section for CH₄ and N₂O from stationary combustion). Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO₂ Emissions from Stationary Fossil Fuel Combustion (MMT CO₂ Eq.)

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
Coal	1,547.6	1,983.8	1,827.6	1,722.7	1,511.2	1,571.3	1,570.4
Natural Gas	175.3	318.8	399.0	408.8	492.2	444.0	443.2
Fuel Oil	97.5	97.9	31.4	25.8	18.3	22.4	25.3
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	842.5	828.0	775.5	773.3	782.9	812.2	813.3
Coal	155.3	115.3	90.1	82.0	74.1	75.7	75.3
Natural Gas	408.9	388.5	407.2	417.3	434.8	451.9	466.0
Fuel Oil	278.3	324.2	278.2	274.0	274.1	284.6	271.9
Commercial	217.4	223.5	220.1	220.7	196.7	221.0	231.9
Coal	12.0	9.3	6.6	5.8	4.1	3.9	4.5
Natural Gas	142.1	162.9	167.7	170.5	156.9	179.1	189.2
Fuel Oil	63.3	51.3	45.8	44.5	35.7	38.0	38.2
Residential	338.3	357.8	334.6	326.8	282.5	329.7	345.1
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	238.0	262.2	258.6	254.7	224.8	266.2	277.6
Fuel Oil	97.4	94.9	76.0	72.2	57.7	63.4	67.5
U.S. Territories	27.9	49.9	41.4	41.5	43.6	43.5	41.0

¹³ Since emission estimates for U.S. Territories cannot be disaggregated by gas in Table 3-10 and Table 3-11, the values for CH₄ and N₂O exclude U.S. territory emissions.

Coal	0.6		3.0		3.4	3.4	3.4	3.4	3.4
Natural Gas	NO		1.3		1.5	1.4	2.6	3.0	3.0
Fuel Oil	27.2		45.6		36.5	36.7	37.6	37.1	34.6
Total	3,246.9		3,860.1		3,630.0	3,520.1	3,327.9	3,444.6	3,470.6

+ Does not exceed 0.05 MMT CO₂ Eq.

NO - Not occurring

Note: Totals may not sum due to independent rounding.

Table 3-10: CH₄ Emissions from Stationary Combustion (MMT CO₂ Eq.)

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electric Power	0.3	0.5	0.5	0.4	0.4	0.4	0.4
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wood	+	+	+	+	+	+	+
Industrial	1.8	1.7	1.5	1.5	1.5	1.5	1.5
Coal	0.4	0.3	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.2	0.1
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	0.9	0.9	1.0	0.9	0.9
Commercial	1.0	1.1	1.1	1.0	0.9	1.0	1.1
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Natural gas	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Wood	0.5	0.5	0.5	0.5	0.4	0.5	0.5
Residential	5.2	4.1	4.0	4.0	3.7	5.0	5.0
Coal	0.2	0.1	NO	NO	NO	NO	NO
Fuel Oil	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Natural Gas	0.5	0.6	0.6	0.6	0.5	0.6	0.6
Wood	4.1	3.1	3.1	3.2	3.0	4.1	4.1
U.S. Territories	+	0.1	0.1	0.1	0.1	0.1	0.1
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	8.5	7.4	7.1	7.1	6.6	8.0	8.1

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N₂O Emissions from Stationary Combustion (MMT CO₂ Eq.)

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	7.4	16.0	18.5	17.6	17.8	19.1	19.6
Coal	6.3	11.6	12.5	11.5	10.2	12.1	12.4
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	1.0	4.3	5.9	6.1	7.5	7.0	7.2
Wood	+	+	+	+	+	+	+
Industrial	3.1	2.9	2.5	2.4	2.4	2.4	2.4
Coal	0.7	0.5	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.5	0.5	0.4	0.4	0.3	0.4	0.3
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.6	1.6	1.4	1.5	1.5	1.5	1.5
Commercial	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1

Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	1.0	0.9	0.8	0.8	0.7	1.0	1.0
Coal	+	+	NO	NO	NO	NO	NO
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.5	0.5	0.5	0.7	0.7
U.S. Territories	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Coal	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	11.9	20.2	22.2	21.3	21.4	22.9	23.4

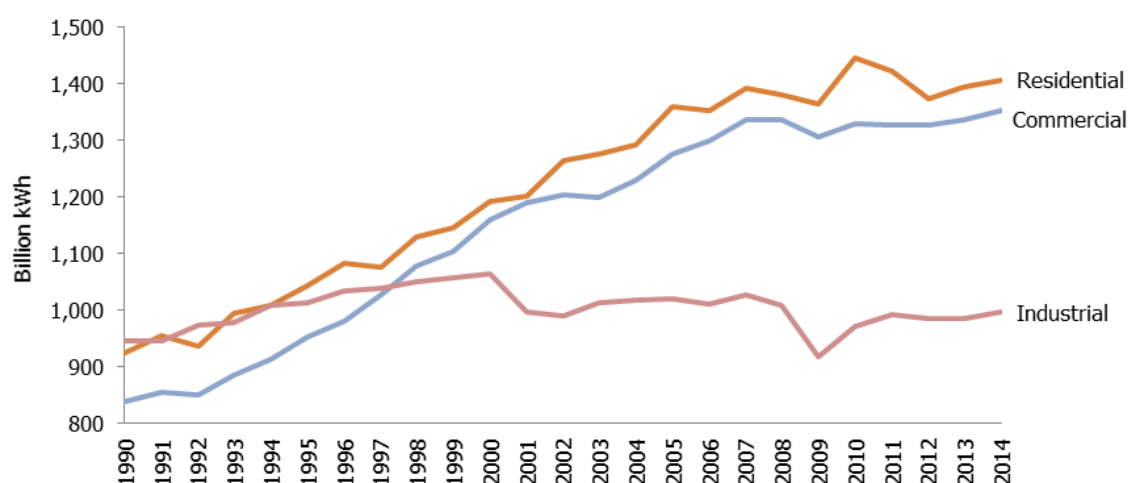
+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO₂ emissions in the United States, representing 37 percent of total CO₂ emissions from all CO₂ emissions sources across the United States. Methane and N₂O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 1.0 percent, respectively. Electricity generation also accounted for the largest share of CO₂ emissions from fossil fuel combustion, approximately 39.2 percent in 2014. Methane and N₂O from electricity generation represented 4.4 and 49.3 percent of total methane and N₂O emissions from fossil fuel combustion in 2014, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9). Electricity generators, including those using low-CO₂ emitting technologies, relied on coal for approximately 39 percent of their total energy requirements in 2014. Recently an increase in the carbon intensity of fuels consumed to generate electricity has occurred due to an increase in coal consumption, and decreased natural gas consumption and other generation sources. Total U.S. electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014 (EIA 2015a).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector (Billion kWh)



The electric power industry includes all power producers, consisting of both regulated utilities and non-utilities (e.g. independent power producers, qualifying co-generators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production

of electricity, while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.¹⁴

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2014 increased approximately 0.9 percent and 1.1 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder, more energy-intensive winter conditions compared to 2013. Electricity sales to the industrial sector in 2014 increased approximately 1.2 percent. Overall, in 2014, the amount of electricity generated (in kWh) increased approximately 1.1 percent relative to the previous year, while CO₂ emissions from the electric power sector increased by 0.1 percent. The increase in CO₂ emissions, despite the relatively larger increase in electricity generation was a result of a slight decrease in the consumption of coal and natural gas for electricity generation by 0.1 percent and 0.2 percent, respectively, in 2014, and an increase in the consumption of petroleum for electricity generation by 15.8 percent.

Industrial Sector

Industrial sector CO₂, CH₄, and N₂O, emissions accounted for 16, 15, and 6 percent of CO₂, CH₄, and N₂O, emissions from fossil fuel combustion, respectively. Carbon dioxide, CH₄, and N₂O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2016 and EIA 2009b).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.¹⁵ In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

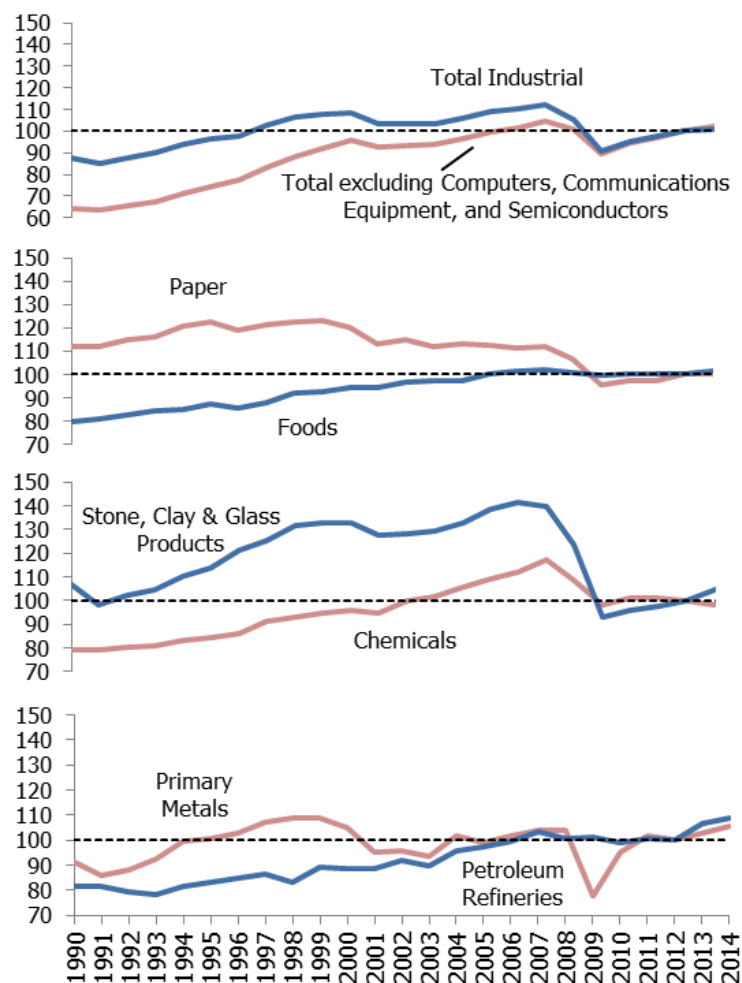
From 2013 to 2014, total industrial production and manufacturing output increased by 3.7 percent (FRB 2015). Over this period, output increased across production indices for Food, Petroleum Refineries, Chemicals, Primary Metals, and Nonmetallic Mineral Products, and decreased slightly for Paper (see Figure 3-10). Through EPA's Greenhouse Gas Reporting Program (GHGRP), industrial trends can be discerned from the overall EIA industrial fuel consumption data used for these calculations. For example, from 2013 to 2014 the underlying EIA data showed increased consumption of natural gas and a decrease in petroleum fuels in the industrial sector. EPA's GHGRP data highlights that chemical manufacturing and nonmetallic mineral products were contributors to these trends.¹⁶

¹⁴ Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

¹⁵ Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

¹⁶ Further details on industrial sector combustion emissions are provided by EPA's GHGRP. See <<http://ghgdata.epa.gov/ghgp/main.do>>.

Figure 3-10: Industrial Production Indices (Index 2007=100)



Despite the growth in industrial output (64 percent) and the overall U.S. economy (78 percent) from 1990 to 2014, CO₂ emissions from fossil fuel combustion in the industrial sector decreased by 3.5 percent over the same time series. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2014, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,416.6 MMT CO₂ Eq., or approximately equal to 2013 emissions.

Residential and Commercial Sectors

Residential and commercial sector CO₂ emissions accounted for 7 and 4 percent of CO₂ emissions from fossil fuel combustion, CH₄ emissions accounted for 49 and 11 percent of CH₄ emissions from fossil fuel combustion, and N₂O emissions accounted for 2 and 1 percent of N₂O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2014, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,093.6 MMT CO₂ Eq. and 946.7 MMT CO₂ Eq., respectively. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 1.5 and 1.4 percent from 2013 to 2014, respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, both sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

In 2014, combustion emissions from natural gas consumption represent 80 and 82 percent of the direct fossil fuel CO₂ emissions from the residential and commercial sectors, respectively. Natural gas combustion CO₂ emissions from the residential and commercial sectors in 2014 increased by 4.3 percent and 5.6 percent from 2013 levels, respectively.

U.S. Territories

Emissions from U.S. Territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described in the Methodology section for CO₂ from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO₂, CH₄, and N₂O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector and Mobile Combustion

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

Transportation End-Use Sector

The transportation end-use sector accounted for 1,760.1 MMT CO₂ Eq. in 2014, which represented 33 percent of CO₂ emissions, 20 percent of CH₄ emissions, and 41 percent of N₂O emissions from fossil fuel combustion, respectively.¹⁷ Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 104.2 MMT CO₂ Eq. in 2014; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

From 1990 to 2014, transportation emissions from fossil fuel combustion rose by 14 percent due, in large part, to increased demand for travel with limited gains in fuel efficiency for much of this time period. The number of vehicle miles traveled (VMT) by light-duty motor vehicles (passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

From 2013 to 2014, CO₂ emissions from the transportation end-use sector increased by 1.4 percent.¹⁸ The increase in emissions can largely be attributed to small increases in VMT and fuel use across many on-road transportation modes. Commercial aircraft emissions have decreased 18 percent since 2007.¹⁹ Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel efficient aircraft.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO₂ from fossil fuel combustion, which increased by 16 percent from 1990 to

¹⁷ Note that these totals include CO₂, CH₄ and N₂O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH₄ and N₂O emissions from transportation rail electricity.

¹⁸ Note that this value does not include lubricants.

¹⁹ Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

2014. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO₂, N₂O, CH₄, and HFCs.

Transportation Fossil Fuel Combustion CO₂ Emissions

Domestic transportation CO₂ emissions increased by 16 percent (244.8 MMT CO₂) between 1990 and 2014, an annualized increase of 0.7 percent. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 60 percent of CO₂ emissions from fossil fuel combustion, medium- and heavy-duty trucks and buses 24 percent, commercial aircraft 7 percent, and other sources 9 percent. See Table 3-12 for a detailed breakdown of transportation CO₂ emissions by mode and fuel type.

Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. Carbon dioxide emissions from the combustion of ethanol and biodiesel for transportation purposes, along with the emissions associated with the agricultural and industrial processes involved in the production of biofuel, are captured in other Inventory sectors.²⁰ Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 12.9 billion gallons in 2014, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.4 billion gallons in 2014. For further information, see the section on biofuel consumption at the end of this chapter and Table A-93 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,046.9 MMT CO₂ in 2014, an increase of 10 percent (96.4 MMT CO₂) from 1990 due, in large part, to increased demand for travel as fleetwide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,181.1 MMT CO₂ in 2004, and since then have declined about 11 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-11) reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, the rate of VMT growth slowed while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 41 percent of new vehicles in model year 2014 (EPA 2015a).

Medium- and heavy-duty truck CO₂ emissions increased by 75 percent from 1990 to 2014. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 94 percent between 1990 and 2014.²¹ Carbon dioxide from the domestic operation of commercial aircraft increased by 5 percent (5.3 MMT CO₂) from 1990 to 2014.²² Across all categories of aviation, excluding international bunkers, CO₂ emissions decreased by 20 percent (37.3 MMT CO₂) between 1990 and 2014.²³ This includes a 56 percent (19.6 MMT CO₂) decrease in CO₂ emissions from domestic military operations.

Transportation sources also produce CH₄ and N₂O; these emissions are included in Table 3-13 and Table 3-14 and in the “Mobile Combustion” Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO₂, CH₄, N₂O, and HFCs.

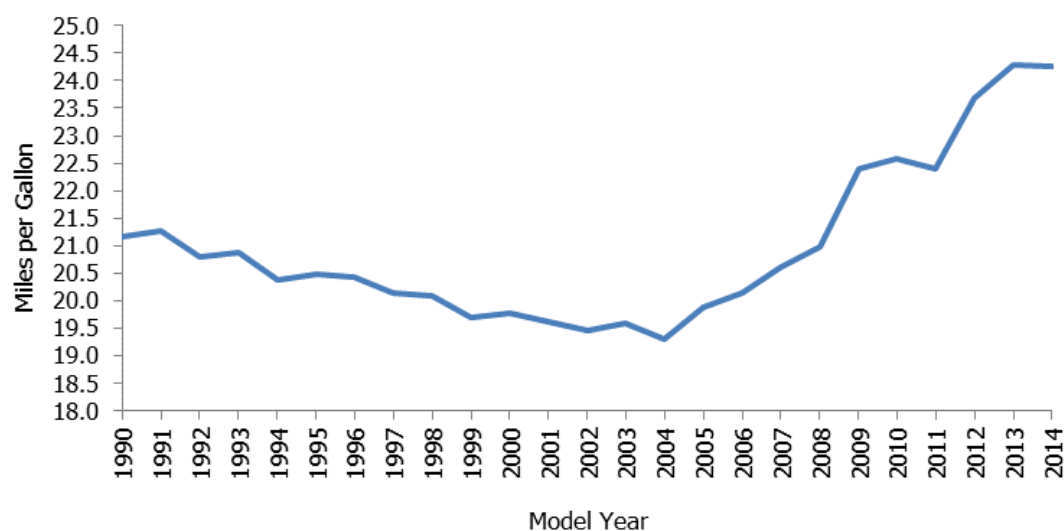
²⁰ Biofuel estimates are presented in the Energy chapter for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 6). More information and additional analyses on biofuels are available at EPA’s “Renewable Fuels: Regulations & Standards;” See <<http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm>>.

²¹ While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2014 time period, part of the growth reflects a method change for estimating VMT starting in 2007. This change in methodology in FHWA’s VM-1 table resulted in large changes in VMT by vehicle class, thus leading to a shift in VMT and emissions among on-road vehicle classes in the 2007 to 2014 time period. During the time period prior to the method change (1990-2006), VMT for medium- and heavy-duty trucks increased by 51 percent.

²² Commercial aircraft, as modeled in FAA’s AEDT, consists of passenger aircraft, cargo, and other chartered flights.

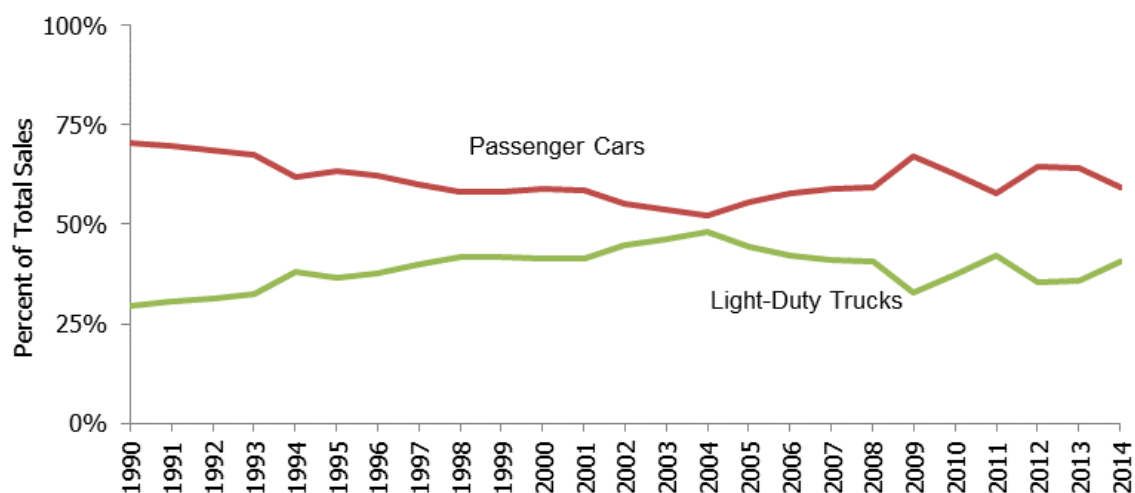
²³ Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2014 (miles/gallon)



Source: EPA (2015)

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2014 (Percent)



Source: EPA (2015)

Table 3-12: CO₂ Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMT CO₂ Eq.)

Fuel/Vehicle Type	1990	2005	2010 ^a	2011	2012	2013	2014
Gasoline^b	983.5	1,183.7	1,092.5	1,068.8	1,064.7	1,065.6	1,083.8
Passenger Cars	621.4	655.9	738.2	732.8	731.4	731.4	733.5
Light-Duty Trucks	309.1	477.2	295.0	280.4	277.4	277.7	293.5

Medium- and Heavy-Duty Trucks ^c	38.7	34.8	42.3	38.9	38.7	39.5	40.0
Buses	0.3	0.4	0.7	0.7	0.8	0.8	0.9
Motorcycles	1.7	1.6	3.6	3.6	4.1	3.9	3.8
Recreational Boats ^d	12.2	13.9	12.6	12.4	12.3	12.3	12.2
Distillate Fuel Oil (Diesel)^{b,e}	262.9	457.5	422.0	430.0	427.5	433.9	447.6
Passenger Cars	7.9	4.2	3.7	4.1	4.1	4.1	4.1
Light-Duty Trucks	11.5	25.8	12.5	13.0	12.9	12.9	13.9
Medium- and Heavy-Duty Trucks ^c	190.5	360.2	342.7	344.4	344.4	350.0	361.3
Buses	8.0	10.6	13.5	14.4	15.4	15.5	16.6
Rail	35.5	45.5	38.6	40.4	39.5	40.1	41.7
Recreational Boats	2.0	3.2	3.6	3.6	3.7	3.7	3.8
Ships and Other Boats ^f	7.5	8.0	7.4	10.1	7.5	7.5	6.2
<i>International Bunker Fuels^g</i>	<i>11.7</i>	<i>9.4</i>	<i>9.5</i>	<i>7.9</i>	<i>6.8</i>	<i>5.6</i>	<i>6.1</i>
Jet Fuel	184.2	189.3	151.5	146.6	143.4	147.1	148.6
Commercial Aircraft ^h	109.9	132.7	113.3	114.6	113.3	114.3	115.2
Military Aircraft	35.0	19.4	13.6	11.6	12.1	11.0	15.4
General Aviation Aircraft	39.4	37.3	24.6	20.4	18.0	21.8	18.0
<i>International Bunker Fuels^g</i>	<i>38.0</i>	<i>60.1</i>	<i>61.0</i>	<i>64.8</i>	<i>64.5</i>	<i>65.7</i>	<i>69.4</i>
<i>International Bunker Fuels from Commercial Aviation</i>	<i>30.0</i>	<i>55.6</i>	<i>57.4</i>	<i>61.7</i>	<i>61.4</i>	<i>62.8</i>	<i>66.3</i>
Aviation Gasoline	3.1	2.4	1.9	1.9	1.7	1.5	1.5
General Aviation Aircraft	3.1	2.4	1.9	1.9	1.7	1.5	1.5
Residual Fuel Oil	22.6	19.3	20.4	19.4	15.8	15.1	5.8
Ships and Other Boats ^f	22.6	19.3	20.4	19.4	15.8	15.1	5.8
<i>International Bunker Fuels^g</i>	<i>53.7</i>	<i>43.6</i>	<i>46.5</i>	<i>38.9</i>	<i>34.5</i>	<i>28.5</i>	<i>27.7</i>
Natural Gas	36.0	33.1	38.1	38.9	41.3	47.0	47.6
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.8	1.1	1.1	1.0	1.1	1.1
Pipeline ⁱ	36.0	32.2	37.1	37.8	40.3	45.9	46.5
LPG	1.4	1.7	1.8	2.1	2.3	2.7	2.7
Light-Duty Trucks	0.6	1.3	1.3	1.5	1.6	1.9	1.9
Medium- and Heavy-Duty Trucks ^c	0.8	0.4	0.6	0.6	0.7	0.8	0.8
Buses	+	+	+	+	+	+	+
Electricity	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Rail	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Ethanol^j	4.1	22.4	71.3	71.5	71.5	73.4	74.8
Total	1,496.8	1,891.8	1,732.7	1,711.9	1,700.6	1,717.0	1,741.7
Total (Including Bunkers)^g	1,600.3	2,004.9	1,849.7	1,823.6	1,806.4	1,816.8	1,844.9

+ Does not exceed 0.05 MMT CO₂ Eq.

^a In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

^b Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27 (FHWA 1996 through 2015). These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c Includes medium- and heavy-duty trucks over 8,500 lbs.

^d In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than two percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^e Updates to the distillate fuel oil heat content data from EIA for years 1993 through 2014 resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

^f Note that large year over year fluctuations in emission estimates partially reflect nature of data collection for these sources.

^g Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

^h Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

ⁱ Pipelines reflect CO₂ emissions from natural gas powered pipelines transporting natural gas.

^j Ethanol estimates are presented for informational purposes only. See Section 3.10 of this chapter and the estimates in Land Use, Land-Use Change, and Forestry (see Chapter 6), in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

Notes: This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation. In addition, this table does not include CO₂ emissions from U.S. Territories, since these are covered in a separate chapter of the Inventory. Totals may not sum due to independent rounding.

Mobile Fossil Fuel Combustion CH₄ and N₂O Emissions

Mobile combustion includes emissions of CH₄ and N₂O from all transportation sources identified in the U.S.

Inventory with the exception of pipelines and electric locomotives;²⁴ mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.).²⁵ Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide mobile fossil fuel CH₄ and N₂O emission estimates in MMT CO₂ Eq.²⁶

Mobile combustion was responsible for a small portion of national CH₄ emissions (0.3 percent) but was the fourth largest source of U.S. N₂O emissions (4.0 percent). From 1990 to 2014, mobile source CH₄ emissions declined by 64 percent, to 2.0 MMT CO₂ Eq. (82 kt CH₄), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH₄ emissions. Mobile source emissions of N₂O decreased by 60 percent, to 16.3 MMT CO₂ Eq. (55 kt N₂O). Earlier generation control technologies initially resulted in higher N₂O emissions, causing a 28 percent increase in N₂O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N₂O output, resulting in a 69 percent decrease in mobile source N₂O emissions from 1997 to 2014 (Figure 3-13). Overall, CH₄ and N₂O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

²⁴ Emissions of CH₄ from natural gas systems are reported separately. More information on the methodology used to calculate these emissions are included in this chapter and Annex 3.4.

²⁵ See the methodology sub-sections of the CO₂ from Fossil Fuel Combustion and CH₄ and N₂O from Mobile Combustion sections of this chapter. Note that N₂O and CH₄ emissions are reported using different categories than CO₂. CO₂ emissions are reported by end-use sector (Transportation, Industrial, Commercial, Residential, U.S. Territories), and generally adhere to a top-down approach to estimating emissions. CO₂ emissions from non-transportation sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective end-use sector (i.e., construction equipment CO₂ emissions are included in the Commercial end-use sector instead of the Transportation end-use sector). CH₄ and N₂O emissions are reported using the "Mobile Combustion" category, which includes non-transportation mobile sources. CH₄ and N₂O emissions estimates are bottom-up estimates, based on total activity (fuel use, VMT) and emissions factors by source and technology type. These reporting schemes are in accordance with IPCC guidance. For informational purposes only, CO₂ emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

²⁶ See Annex 3.2 for a complete time series of emission estimates for 1990 through 2014.

Figure 3-13: Mobile Source CH₄ and N₂O Emissions (MMT CO₂ Eq.)

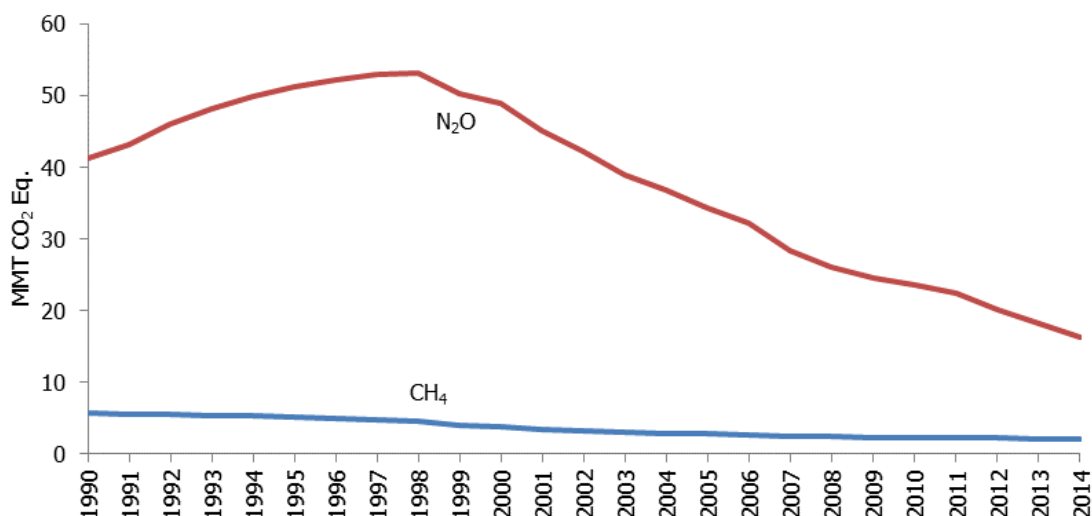


Table 3-13: CH₄ Emissions from Mobile Combustion (MMT CO₂ Eq.)

Fuel Type/Vehicle Type ^a	1990	2005	2010	2011	2012	2013	2014
Gasoline On-Road^b	5.2	2.2	1.7	1.6	1.5	1.5	1.4
Passenger Cars	3.2	1.2	1.2	1.2	1.1	1.0	1.0
Light-Duty Trucks	1.7	0.8	0.4	0.4	0.3	0.3	0.3
Medium- and Heavy-Duty Trucks and Buses	0.3	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road^b	+	+	+	+	+	+	+
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road^c	+	+	+	+	+	+	+
Non-Road^d	0.4	0.5	0.5	0.5	0.6	0.6	0.6
Ships and Boats	+	+	+	+	+	+	+
Rail ^e	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment ^f	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Construction/Mining Equipment ^g	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other ^h	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	5.6	2.7	2.3	2.2	2.2	2.1	2.0

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2 for definitions of on-road vehicle types.

^b Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in the current inventory and apply to the 1990 through 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^dIn 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than 2 percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^eRail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^fIncludes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^gIncludes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^h“Other” includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. Totals may not sum due to independent rounding.

Table 3-14: N₂O Emissions from Mobile Combustion (MMT CO₂ Eq.)

Fuel Type/Vehicle Type ^a	1990	2005	2010	2011	2012	2013	2014
Gasoline On-Road^b	37.5	29.9	19.2	18.0	15.7	13.8	12.1
Passenger Cars	24.1	15.9	12.9	12.3	10.7	9.3	7.9
Light-Duty Trucks	12.8	13.2	5.5	5.0	4.4	3.9	3.6
Medium- and Heavy-Duty Trucks and Buses	0.5	0.8	0.8	0.7	0.6	0.6	0.5
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road^b	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Alternative Fuel On-Road^c	+	+	+	0.1	0.1	0.1	0.1
Non-Road^d	3.5	4.1	4.0	4.0	3.9	3.9	3.8
Ships and Boats	0.6	0.6	0.8	0.8	0.7	0.7	0.5
Rail ^e	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Aircraft	1.7	1.8	1.4	1.4	1.3	1.4	1.4
Agricultural Equipment ^f	0.2	0.4	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment ^g	0.3	0.5	0.6	0.6	0.6	0.6	0.6
Other ^h	0.4	0.6	0.6	0.6	0.6	0.6	0.6
Total	41.2	34.4	23.6	22.4	20.0	18.2	16.3

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2 for definitions of on-road vehicle types.

^b Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in the current Inventory and apply to the 1990 through 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^d In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than two percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^e Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^f Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^g Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^h "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Notes: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. Totals may not sum due to independent rounding.

CO₂ from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO₂ emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).²⁷ The use of the most recently published calculation methodologies by the IPCC, as contained in the *2006 IPCC Guidelines*, is considered to improve the rigor and accuracy of this Inventory and is fully in line with IPCC Good Practice Guidance. A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the EIA of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2016). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).²⁸

For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this Inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every four years). These consumption data sets help inform the annual surveys to arrive at the national total and sectoral breakdowns for that total.²⁹

²⁷ The IPCC Tier 3B methodology is used for estimating emissions from commercial aircraft.

²⁸ Fuel consumption by U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed total emissions of 41.2 MMT CO₂ Eq. in 2014.

²⁹ See IPCC Reference Approach for estimating CO₂ emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

Also, note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).³⁰

2. *Subtract uses accounted for in the Industrial Processes and Product Use chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the Industrial Processes and Product Use chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2013), Coffeyville (2014), U.S. Census Bureau (2011), EIA (2016), USGS (1991 through 2011), USGS (1994 through 2011), USGS (1995, 1998, 2000 through 2002), USGS (2007), USGS (2009), USGS (2010), USGS (2011), USGS (1991 through 2010a), USGS (1991 through 2010b), USGS (2012a) and USGS (2012b).³¹
3. *Adjust for conversion of fuels and exports of CO₂.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO₂.³² Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.³³ Since October 2000, the Dakota Gasification Plant has been exporting CO₂ to Canada by pipeline. Since this CO₂ is not emitted to the atmosphere in the United States, energy used to produce this CO₂ is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2015), data for synthetic natural gas were collected from EIA (2014), and data for CO₂ exports were collected from the Eastman Gasification Services Company (2011), Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2008) and DOE (2012).
4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on data from the Federal Highway Administration that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2015), Benson (2002 through 2004), DOE (1993 through 2015), EIA (2007), EIA (1991 through 2015), EPA (2015c), and FHWA (1996 through 2015).³⁴

³⁰ A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

³¹ See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes and Product Use chapter.

³² Energy statistics from EIA (2015) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

³³ These adjustments are explained in greater detail in Annex 2.1.

³⁴ The source of highway vehicle VMT and fuel consumption is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990 to 2010 Inventory and apply to the 2007 to 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2016).
6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).³⁵ The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2015) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2016); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2014) for 1990 through 2001 and 2007 through 2014, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail in the International Bunker Fuels section of this chapter.
7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO₂. The C content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse Gases in the United States 2008* (EIA 2009a), and an EPA analysis of C content coefficients used in the GHGRP (EPA 2010). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.
8. *Estimate CO₂ Emissions.* Total CO₂ emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).
9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and densities were obtained from EIA (2016) and USAF (1998).³⁶
 - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2014); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2013).
 - For non-road vehicles, activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (2016), Benson (2002 through 2004), DOE (1993 through 2015), DLA Energy (2015), DOC (1991 through 2015), DOT (1991 through 2015), EIA (2009a), EIA (2016), EIA (2013), EIA (1991 through 2015), EPA (2015c), and Gaffney (2007).

³⁵ See International Bunker Fuels section in this chapter for a more detailed discussion.

³⁶ For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO₂) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8.

- For jet fuel used by aircraft, CO₂ emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent IPCC (2006) (see Annex 3.3). Carbon dioxide emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

Box 3-4: Uses of Greenhouse Gas Reporting Program Data and Improvements in Reporting Emissions from Industrial Sector Fossil Fuel Combustion

As described in the calculation methodology, total fossil fuel consumption for each year is based on aggregated end-use sector consumption published by the EIA. The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) has provided an opportunity to better characterize the industrial sector's energy consumption and emissions in the United States, through a disaggregation of EIA's industrial sector fuel consumption data from select industries.

For EPA's GHGRP 2010, 2011, 2012, 2013, and 2014 reporting years, facility-level fossil fuel combustion emissions reported through the GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the Inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.³⁷

This year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the Inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.³⁸ For the current exercise, the efforts in reconciling fuels focused on standard, common fuel types (e.g., natural gas, distillate fuel oil, etc.) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future Inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics. Additionally, this year's analysis expanded this effort through the full time series presented in the CRF tables. Analyses were conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data in order to disaggregate the full 1990 through 2014 time series in the CRF tables. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports.

Additionally, to assist in the disaggregation of industrial fuel consumption, EIA will now synthesize energy consumption data using the same procedure as is used for the last historical (benchmark) year of the Annual Energy Outlook (AEO). This procedure reorganizes the most recent data from the Manufacturing Energy Consumption Survey (MECS) (conducted every four years) into the nominal data submission year using the same energy-economy integrated model used to produce the AEO projections, the National Energy Modeling System (NEMS). EIA believes this "nowcasting" technique provides an appropriate estimate of energy consumption for the CRF.

To address gaps in the time series, EIA performs a NEMS model projection, using the MECS baseline sub-sector energy consumption. The NEMS model accounts for changes in factors that influence industrial sector energy consumption, and has access to data which may be more recent than MECS, such as industrial sub-sector macro industrial output (i.e., shipments) and fuel prices. By evaluating the impact of these factors on industrial subsector

³⁷ See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

³⁸ See <<http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>>.

energy consumption, NEMS can anticipate changes to the energy shares occurring post-MECS and can provide a way to appropriately disaggregate the energy-related emissions data into the CRF.

While the fuel consumption values for the various manufacturing sub-sectors are not directly surveyed for all years, they represent EIA's best estimate of historical consumption values for non-MECS years. Moreover, as an integral part of each AEO publication, this synthetic data series is likely to be maintained consistent with all available EIA and non-EIA data sources even as the underlying data sources evolve for both manufacturing and non-manufacturing industries alike.

Other sectors' fuel consumption (commercial, residential, transportation) will be benchmarked with the latest aggregate values from the Monthly Energy Review.³⁹ EIA will work with EPA to back cast these values to 1990.

Box 3-5: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO₂ is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO₂ emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 MMT CO₂ Eq./QBtu for natural gas to upwards of 95 MMT CO₂ Eq./QBtu for coal and petroleum coke.⁴⁰ In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For the purposes of following reporting guidelines and maintaining the focus of this section, renewable energy and nuclear electricity and consumption are not included in the totals shown in Table 3-15 in order to focus attention on fossil fuel combustion as detailed in this chapter. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT CO₂ Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO₂ Eq./QBtu)

Sector	1990	2005	2010	2011	2012	2013	2014
Residential ^a	57.4	56.6	55.8	55.7	55.5	55.3	55.4
Commercial ^a	59.1	57.5	56.8	56.6	56.1	55.8	55.8
Industrial ^a	64.3	64.3	62.9	62.4	62.0	61.8	61.5
Transportation ^a	71.1	71.4	71.5	71.5	71.5	71.4	71.4
Electricity Generation ^b	87.3	85.8	83.5	82.9	79.9	81.3	81.3
U.S. Territories ^c	73.0	73.4	73.1	73.1	72.4	72.1	71.6
All Sectors^c	73.0	73.5	72.4	72.0	70.9	70.9	70.7

^a Does not include electricity or renewable energy consumption.

³⁹ See <<http://www.eia.gov/totalenergy/data/monthly/>>.

⁴⁰ One exajoule (EJ) is equal to 10¹⁸ joules or 0.9478 QBtu.

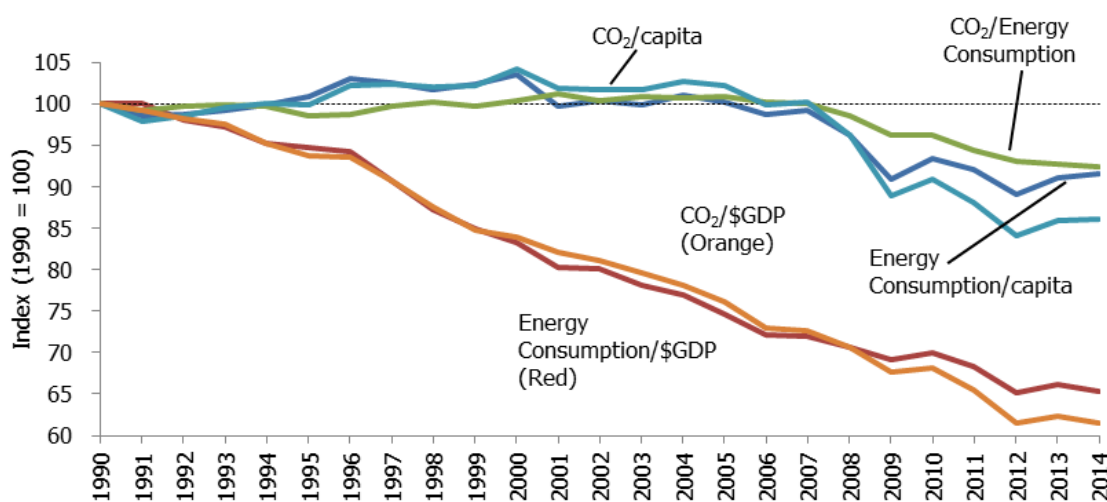
^b Does not include electricity produced using nuclear or renewable energy.

^c Does not include nuclear or renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption.

Over the twenty-five-year period of 1990 through 2014, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2014 was approximately 8.5 percent below levels in 1990 (see Figure 3-14). To differentiate these estimates from those of Table 3-15, the C intensity trend shown in Figure 3-14 and described below includes nuclear and renewable energy EIA data to provide a comprehensive economy-wide picture of energy consumption. Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO₂ emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2016).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO₂ Emissions Per Capita and Per Dollar GDP



C intensity estimates were developed using nuclear and renewable energy data from EIA (2016), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty and Time-Series Consistency

For estimates of CO₂ from fossil fuel combustion, the amount of CO₂ emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO₂ emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO₂ emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the

more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO₂ emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption. The amount of CO₂ emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO₂ estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. Territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO₂ emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO₂ from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO₂ from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.⁴¹ Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.⁴²

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).⁴³ For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO₂ emissions in 2014 were estimated to be between 5,102.4 and 5,457.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2014 emission estimate of 5,208.2 MMT CO₂ Eq.

⁴¹ SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

⁴² In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

⁴³ Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Table 3-16: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq. and Percent)

Fuel/Sector	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
		(MMT CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal^b	1,653.7	1,596.3	1,809.1	-3%	9%
Residential	NE	NE	NE	NE	NE
Commercial	4.5	4.3	5.2	-5%	15%
Industrial	75.3	71.8	87.2	-5%	16%
Transportation	NE	NE	NE	NE	NE
Electricity Generation	1,570.4	1,509.0	1,721.0	-4%	10%
U.S. Territories	3.4	3.0	4.0	-13%	19%
Natural Gas^b	1,426.6	1,411.4	1,492.7	-1%	5%
Residential	277.6	269.7	297.1	-3%	7%
Commercial	189.2	183.8	202.4	-3%	7%
Industrial	466.0	452.1	499.6	-3%	7%
Transportation	47.6	46.3	51.0	-3%	7%
Electricity Generation	443.2	430.4	465.6	-3%	5%
U.S. Territories	3.0	2.6	3.5	-12%	17%
Petroleum^b	2,127.5	1,997.0	2,251.9	-6%	6%
Residential	67.5	63.8	71.0	-5%	5%
Commercial	38.2	36.3	40.0	-5%	5%
Industrial	271.9	219.1	321.2	-19%	18%
Transportation	1,690.0	1,577.3	1,800.7	-7%	7%
Electric Utilities	25.3	24.1	27.3	-5%	8%
U.S. Territories	34.6	31.9	38.5	-8%	11%
Total (excluding Geothermal)^b	5,207.8	5,102.0	5,457.0	-2%	5%
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal)^{b,c}	5,208.2	5,102.4	5,457.4	-2%	5%

NE (Not Estimated)

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

^b The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.

^c Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO₂ emissions from geothermal production.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for CO₂ from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO₂ emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2016) updated energy consumption statistics across the time series relative to the previous Inventory. One such revision is the historical coal and petroleum product consumption in the industrial sector for the entire time series. In addition, EIA revised 2013 natural gas consumption in the

transportation sector and 2013 kerosene and Liquefied Petroleum Gas (LPG) consumption in the residential and commercial sectors.

Kerosene consumption increased in the residential sector by 9 percent in 2013 and decreased by 14 and 25 percent in the commercial and industrial sectors in 2013, respectively. Transportation sector distillate fuel consumption decreased by 0.4 percent across the entire time series.

In early 2015, EIA revised the heat content used to calculate the energy of distillate fuel oil consumption. Previously, a single constant factor (5.825 MMBtu/barrel) from EIA's Monthly Energy Review (MER) Table A1 was applied to the volumetric data. For the January 2015 release, this single constant factor in Table A1 was replaced with heat content factors for distillate fuel oil by sulfur content. Instead of using the factor(s) listed in Table A1, EIA began to use an annually variable quantity-weighted factor (5.774 MMBtu/barrel for 2013) that was added to Table A3. EIA notes that quantity-weighted averages of the sulfur-content categories of distillate fuel oil are calculated by using heat content values shown in Table A1, and that these values exclude renewable diesel fuel (including biodiesel) blended into distillate fuel oil.

Overall, these changes resulted in an average annual decrease of 1.1 MMT CO₂ Eq. (less than 0.1 percent) in CO₂ emissions from fossil fuel combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

To reduce uncertainty of CO₂ from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. Territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO₂ from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

The availability of facility-level combustion emissions through EPA's GHGRP will continue to be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.⁴⁴ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from fossil fuel combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national energy statistics. Additional work will commence to ensure CO₂ emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will continue to be relied upon.⁴⁵

Another planned improvement is to develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates is currently being investigated.

An additional potential improvement is to include CO₂ emissions from natural gas (LNG and CNG) use in medium- and heavy-duty trucks, light trucks and passenger cars. Currently data from the Transportation Energy Data book is

⁴⁴ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

⁴⁵ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

used to allocate CO₂ emissions to vehicle categories. However, this data source only estimates natural gas use in buses. We are currently investigating the use of alternative data sources from the EIA that would allow some of the CO₂ from natural gas consumption to be allocated to these other vehicle categories.

In addition, we are investigating an approach to account for CO₂ emissions from the use of urea-based additives in catalytic converters for on-road vehicles between 2010 and 2014. The approach would utilize the MOVES model to estimate fuel use by diesel vehicles with urea-based catalysts. The *2006 IPCC Guidelines* estimates urea use between one and three percent of diesel fuel used.

CH₄ and N₂O from Stationary Combustion

Methodology

Methane and N₂O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type for industrial, residential, commercial, and U.S. Territories; and by fuel and technology type for the electric power sector). Beginning with the current Inventory report, the electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1 methodology. The activity data and emission factors used are described in the following subsections.

Industrial, Residential, Commercial, and U.S. Territories

National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, and U.S. Territories. For the CH₄ and N₂O estimates, wood consumption data for the United States was obtained from EIA's Monthly Energy Review (EIA 2016). Fuel consumption data for coal, natural gas, and fuel oil for the United States were also obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2016). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).⁴⁶ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.⁴⁷ Construction and agricultural fuel use was obtained from EPA (2014). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA. Tier 1 default emission factors for these three end-use sectors were provided by the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). U.S. Territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

Electric Power Sector

The electric power sector now uses a Tier 2 emission estimation methodology as fuel consumption for the electricity generation sector by control-technology type was obtained from EPA's Acid Rain Program Dataset (EPA 2015a). This combustion technology- and fuel-use data was available by facility from 1996 to 2014. The Tier 2 emission factors used were taken from IPCC (2006), which in turn are based on emission factors published by EPA.

Since there was a difference between the EPA (2015a) and EIA (2016) total energy consumption estimates, the remaining energy consumption from EIA (2016) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2014.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2015a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2016) and the ratio of combustion technology and fuel types from EPA (2015a). The consumption estimates from 1990 to 1995 were estimated by

⁴⁶ U.S. Territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

⁴⁷ Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995. Emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2015a) and EIA (2016) datasets. The higher wood biomass consumption from EIA (2016) in the electric power sector was distributed to the residential, commercial, and industrial sectors according to their percent share of wood biomass energy consumption calculated from EIA (2016).

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty and Time-Series Consistency

Methane emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH₄ and N₂O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH₄ and N₂O stationary source inventory estimation models with the model for CO₂ from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO₂ emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N₂O emission factors, based on the SAIC/EIA (2001) report.⁴⁸ For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).⁴⁹ However, the CH₄ emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH₄ emissions in 2014 (*including* biomass) were estimated to be between 4.8 and 20.6 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 41 percent below to 155 percent above the 2014 emission estimate of 8.1 MMT CO₂ Eq.⁵⁰ Stationary combustion N₂O emissions in 2014 (*including* biomass) were estimated to be between 17.9 and 34.2 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 46 percent above the 2014 emissions estimate of 23.4 MMT CO₂ Eq.

⁴⁸ SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

⁴⁹ In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

⁵⁰ The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Stationary Combustion	CH ₄	8.1	4.8	20.6	-41%	+155%
Stationary Combustion	N ₂ O	23.4	17.9	34.2	-24%	+46%

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH₄ and N₂O are greater than those associated with estimates of CO₂ from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH₄ and N₂O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH₄, N₂O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Methane and N₂O emissions from stationary sources (excluding CO₂) across the entire time series were revised due to revised data from EIA (2016) and EPA (2015a) relative to the previous Inventory. The CH₄ emission estimates were also revised due to a corrected emission factor for Natural Gas Combined Cycle gas turbines that was corrected from 1 g/GJ to 4 g/GJ, per IPCC (2006). The historical data changes resulted in an average annual increase of less than 0.1 MMT CO₂ Eq. (less than 0.1 percent) in CH₄ emissions, and an average annual decrease of less than 0.1 MMT CO₂ Eq. (less than 0.1 percent) in N₂O emissions from stationary combustion for the period 1990 through 2013.

Planned Improvements

Several items are being evaluated to improve the CH₄ and N₂O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. Territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Future improvements to the CH₄ and N₂O from Stationary Combustion category involve research into the availability of CH₄ and N₂O from stationary combustion data, and analyzing data reported under EPA's GHGRP. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for CH₄ and N₂O from Stationary Combustion category, particular attention will be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all Inventory years as reported in this Inventory. In

implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁵¹

CH₄ and N₂O from Mobile Combustion

Methodology

Estimates of CH₄ and N₂O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH₄ and N₂O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH₄ and N₂O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs) are based on VMT and emission factors by vehicle and fuel type.⁵²

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO₂, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.⁵³

Emission factors for AFVs were first developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2014 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2015).⁵⁴ VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories

⁵¹ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

⁵² Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

⁵³ Additional information regarding the model can be found online at <<http://www.epa.gov/OMS/m6.htm>>.

⁵⁴ The source of VMT is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through

using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2015) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2015). VMT for AFVs were estimated based on Browning (2015). The age distributions of the U.S. vehicle fleet were obtained from EPA (2015b, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2015b).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998, 1999a) and IPCC (2006).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N₂O and CH₄ per kilogram of fuel consumed).⁵⁵ Activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DHS (2008), DLA Energy (2015), DOC (1991 through 2015), DOE (1993 through 2015), DOT (1991 through 2015), EIA (2002, 2007, 2015a), EIA (2007 through 2015), EIA (1991 through 2015), EPA (2015b), Esser (2003 through 2004), FAA (2016), FHWA (1996 through 2015), Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2014 estimates of CH₄ and N₂O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) VMT data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see Section 1.7 Uncertainty Analysis of Emission Estimates. However, a much higher level of uncertainty is associated with CH₄ and N₂O emission factors due to limited emission test data, and because, unlike CO₂ emissions, the emission pathways of CH₄ and N₂O are highly complex.

Mobile combustion CH₄ emissions from all mobile sources in 2014 were estimated to be between 1.8 and 2.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 12 percent below to 18 percent above the corresponding 2014 emission estimate of 2.0 MMT CO₂ Eq. Also at a 95 percent confidence level, mobile combustion N₂O emissions from mobile sources in 2014 were estimated to be between 15.7 and 20.7 MMT CO₂ Eq., indicating a range of 4 percent below to 27 percent above the corresponding 2014 emission estimate of 16.3 MMT CO₂ Eq.

2014 time period. This resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

⁵⁵ The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

Table 3-18: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Mobile Sources (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate ^a (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH ₄	2.0	1.8	2.4	-12%	+18%
Mobile Sources	N ₂ O	16.3	15.7	20.7	-4%	+27%

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Approach 2 uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH₄ and N₂O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA/QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

Decreases to CH₄ and N₂O emissions from mobile combustion are largely due to updates made to the Motor Vehicle Emissions Simulator (MOVES 2014a) model that is used to estimate on-road gasoline vehicle distribution and mileage across the time series. These changes are due to the updated MOVES age distributions for years 1999 through 2013 in this year's Inventory. These changes in the age distribution increased the percentage of vehicles and VMT for some vehicle types in newer model years that have better emissions control technology. For aircrafts, a weighted jet fuel heat content was applied to the jet fuel N₂O emissions calculation. The weighted factor accounts for the different heat contents of jet fuels used in commercial aviation, general aviation and the military. This resulted in a 0.4 percent increase in the heat content and a similar increase in N₂O emissions.

Estimates of alternative fuel vehicle mileage were also revised to reflect updates made to Energy Information Administration (EIA) data on alternative fuel use and vehicle counts. The energy economy ratios (EERs) in the alternative fuel vehicle analysis were also updated in this Inventory. EERs are the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles. These were taken from the Argonne National Laboratory's GREET model (ANL 2015). Most of the energy economy ratios were within 10 percent of their previous values. More significant changes occurred with Neighborhood Electric Vehicles (NEVs) (-26 percent), Electric Vehicles (EVs) (17 percent), Hydrogen Fuel Cell Vehicles (-15 percent), Neat Methanol Internal Combustion Engines (ICEs) (12 percent), Neat Ethanol ICEs (25 percent), LPG ICEs (11 percent) and LPG Bi-fuel (11 percent). Increases in EERs increase miles per gallon, estimated VMT, and emissions.

Overall, these changes resulted in an average annual decrease of 0.1 MMT CO₂ Eq. (4 percent) in CH₄ emissions and an average annual decrease of 1.4 MMT CO₂ Eq. (3 percent) in N₂O emissions from mobile combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

While the data used for this report represent the most accurate information available, several areas have been identified that could potentially be improved in the near term given available resources.

- Develop improved estimates of domestic waterborne fuel consumption. The Inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates is currently being investigated. Additionally, the feasibility of including data from a broader range of domestic and international sources for domestic bunker fuels, including data from studies such as the *Third IMO GHG Study 2014*, is being considered.
- Continue to examine the use of EPA's MOVES model in the development of the Inventory estimates, including use for uncertainty analysis. Although the Inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. The use of MOVES will be further explored.

3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO₂ emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 60 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 40 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of this Inventory. For example, some of the NEU products release CO₂ at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO₂ emissions accounted for in the Industrial Processes and Product Use chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations adjust for the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2014 from the non-energy uses of fossil fuels were 114.3 MMT CO₂ Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2014, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,761.2 TBtu, an increase of 6.3 percent since 1990 (see Table 3-20). About 55.9 MMT (205.1 MMT CO₂ Eq.) of the C in these fuels was stored, while the remaining 31.2 MMT C (114.3 MMT CO₂ Eq.) was emitted.

Table 3-19: CO₂ Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO₂ Eq. and percent)

Year	1990	2005	2010	2011	2012	2013	2014
Potential Emissions	312.1	377.5	325.1	316.6	311.9	327.1	319.5
C Stored	194.0	238.6	211.0	208.1	206.2	205.4	205.1
Emissions as a % of Potential	38%	37%	35%	34%	34%	37%	36%
Emissions	118.1	138.9	114.1	108.5	105.6	121.7	114.3

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2013, 2015b) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and Product Use chapter.^{56,57} Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in the Energy sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC (2006), which in turn draws from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (Tbtu)

Year	1990	2005	2010	2011	2012	2013	2014
Industry	4,215.8	5,110.9	4,572.7	4,470.2	4,377.4	4,621.4	4,571.6
Industrial Coking Coal	+	80.4	64.8	60.8	132.5	119.6	23.0
Industrial Other Coal	8.2	11.9	10.3	10.3	10.3	10.3	10.3
Natural Gas to Chemical Plants	281.6	260.9	298.7	297.1	292.7	297.0	305.1

⁵⁶ These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

⁵⁷ Some degree of double counting may occur between these estimates of non-energy use of fuels and process emissions from petrochemical production presented in the Industrial Processes and Product Use sector. Data integration is not feasible at this time as feedstock data from EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries (e.g., petrochemical production) as currently collected through EPA's GHGRP and used for the petrochemical production category.

Asphalt & Road Oil	1,170.2	1,323.2	877.8	859.5	826.7	783.3	792.6
LPG	1,120.5	1,610.1	1,834.0	1,865.7	1,887.3	2,062.9	2,109.4
Lubricants	186.3	160.2	149.5	141.8	130.5	138.1	144.0
Pentanes Plus	117.6	95.5	75.3	26.4	40.3	45.4	43.5
Naphtha (<401 °F)	326.3	679.6	474.5	469.4	432.2	498.8	435.2
Other Oil (>401 °F)	662.1	499.5	433.2	368.2	267.4	209.1	236.2
Still Gas	36.7	67.7	147.8	163.6	160.6	166.7	164.6
Petroleum Coke	27.2	105.2	+	+	+	+	+
Special Naphtha	100.9	60.9	25.3	21.8	14.1	96.6	104.4
Distillate Fuel Oil	7.0	11.7	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	17.1	15.1	15.3	16.5	14.8
Miscellaneous Products	137.8	112.8	158.7	164.7	161.6	171.2	182.7
Transportation	176.0	151.3	141.2	133.9	123.2	130.4	136.0
Lubricants	176.0	151.3	141.2	133.9	123.2	130.4	136.0
U.S. Territories	86.7	121.9	56.4	56.7	58.1	57.4	53.6
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	86.0	117.3	55.4	55.7	57.1	56.4	52.6
Total	4,478.5	5,384.1	4,770.3	4,660.9	4,558.7	4,809.2	4,761.2

+ Does not exceed 0.05 TBtu

NA - Not Applicable

Note: Totals may not sum due to independent rounding.

Table 3-21: 2014 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use ^a (TBtu)	Carbon Content Coefficient (MMT C/QBtu)	Potential Carbon (MMT C)	Storage Factor	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO ₂ Eq.)
Industry	4,571.6	NA	83.3	NA	55.6	27.7	101.6
Industrial Coking Coal	23.0	31.00	0.7	0.04	0.1	0.6	2.4
Industrial Other Coal	10.3	25.82	0.3	0.65	0.2	0.1	0.3
Natural Gas to							
Chemical Plants	305.1	14.46	4.4	0.65	2.9	1.5	5.6
Asphalt & Road Oil	792.6	20.55	16.3	1.00	16.2	0.1	0.3
LPG	2,109.4	17.06	36.0	0.65	23.6	12.4	45.6
Lubricants	144.0	20.20	2.9	0.09	0.3	2.6	9.7
Pentanes Plus	43.5	19.10	0.8	0.65	0.5	0.3	1.1
Naphtha (<401° F)	435.2	18.55	8.1	0.65	5.3	2.8	10.2
Other Oil (>401° F)	236.2	20.17	4.8	0.65	3.1	1.6	6.0
Still Gas	164.6	17.51	2.9	0.65	1.9	1.0	3.6
Petroleum Coke	+	27.85	+	0.04	+	+	+
Special Naphtha	104.4	19.74	2.1	0.65	1.3	0.7	2.6
Distillate Fuel Oil	5.8	20.17	0.1	0.04	0.1	0.1	0.2
Waxes	14.8	19.80	0.3	0.58	0.2	0.1	0.5
Miscellaneous Products	182.7	20.31	3.7	0.04	0.0	3.7	13.6
Transportation	136.0	NA	2.7	NA	0.3	2.5	9.1
Lubricants	136.0	20.20	2.7	0.09	0.3	2.5	9.1
U.S. Territories	53.6	NA	1.1	NA	0.1	1.0	3.5
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	52.6	20.00	1.1	0.04	0.1	0.9	3.5
Total	4,761.2		87.1		55.9	31.2	114.3

+ Does not exceed 0.05 TBtu

NA - Not Applicable

^aTo avoid double counting, net exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2015a), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011), and the Chemical Data Access Tool (EPA 2012); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013b, 2015b); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2012, 2013, 2014); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990-2015); Gosselin, Smith, and Hodge (1984); EPA's Municipal Solid Waste (MSW) Facts and Figures (EPA 2013a; 2014a); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001-2013); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003-2011, 2012, 2013, 2014a, 2014b, 2015); and the *Guide to the Business of Chemistry* (ACC 2015b). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Approach 2 methodology (Monte Carlo Stochastic Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-20 and Table 3-21), the storage factors were taken directly from IPCC (2006), where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2014 was estimated to be between 86.2 and 162.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 42 percent above the 2014 emission estimate of 114.3 MMT CO₂ Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Non-Energy Uses of Fossil Fuels (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	75.1	49.6	125.3	-34%	67%
Asphalt	CO ₂	0.3	0.1	0.6	-57%	117%
Lubricants	CO ₂	18.9	15.5	21.9	-18%	16%
Waxes	CO ₂	0.5	0.3	0.7	-28%	63%
Other	CO ₂	19.6	14.1	21.7	-28%	11%
Total	CO₂	114.3	86.2	162.9	-25%	42%

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: Totals may not sum due to independent rounding.

Table 3-23: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2014 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate ^a			
			(%)		(% , Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	65%	52%	72%	-20%	10%
Asphalt	CO ₂	99.6%	99.1%	99.8%	-0.5%	0.25%
Lubricants	CO ₂	9%	4%	17%	-57%	88%
Waxes	CO ₂	58%	49%	70%	-15%	22%
Other	CO ₂	4%	4%	24%	-3%	479%

^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-23, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses

involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2013 as well as their trends across the time series.

Petrochemical input data reported by EIA will continue to be investigated in an attempt to address an input/output discrepancy in the NEU model. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. Starting in 2001 through 2009, outputs exceeded inputs. In 2010 and 2011, inputs exceeded outputs, and in 2012, outputs slightly exceeded inputs. A portion of this discrepancy has been reduced and two strategies have been developed to address the remaining portion (see Planned Improvements, below).

Recalculations Discussion

A number of updates to historical production values were included in the most recent Monthly Energy Review; these have been populated throughout this document.

Planned Improvements

There are several improvements planned for the future:

- Analyzing the fuel and feedstock data from EPA's GHGRP to better disaggregate CO₂ emissions in NEU model and CO₂ process emissions from petrochemical production.
- More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the C mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued. First, accounting of C in imports and exports will be improved. The import/export adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, reconsider the use of top-down C input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up C output calculation will be considered instead.
- Response to potential changes in NEU input data. In 2013 EIA initiated implementation of new data reporting definitions for Natural Gas Liquids (NGL) and Liquefied Petroleum Gases (LPG); the new definitions may affect the characterization of the input data that EIA provides for the NEU model and may therefore result in the need for changes to the NEU methodology. EIA also obtains and applies proprietary data for LPG inputs that are not directly applied as NEU input data because the data are proprietary. The potential use of the proprietary data (in an aggregated, non-proprietary form) as inputs to the NEU model will be investigated with EIA.
- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses. For example, "miscellaneous

products” category includes miscellaneous products that are not reported elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that are being reported in the “miscellaneous products” category; however, EIA has indicated that recovered sulfur from petroleum and natural gas processing, and potentially also C black feedstock could be reported in this category. Recovered sulfur would not be reported in the NEU calculation or elsewhere in the Inventory.

- Updating the average C content of solvents was researched, since the entire time series depends on one year’s worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive C in solvents. Additional sources of solvents data will be identified in order to update the C content assumptions.
- Updating the average C content of cleansers (soaps and detergents) was researched; although production and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C content) of cleansers has not been recently updated. Recently available composition data sources may facilitate updating the average C content for this category.
- Revising the methodology for consumption, production, and C content of plastics was researched; because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.
- Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal, distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by analyzing C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon black abraded and stored in tires.

Box 3-6: Reporting of Lubricants, Waxes, and Asphalt and Road Oil Product Use in Energy Sector

IPCC (2006) provides methodological guidance to estimate emissions from the first use of fossil fuels as a product for primary purposes other than combustion for energy purposes (including lubricants, paraffin waxes, bitumen/asphalt, and solvents) under the Industrial Processes and Product Use (IPPU) sector.⁵⁸ In this Inventory, C storage and C emissions from product use of lubricants, waxes, and asphalt and road oil are reported under the Energy sector in the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category (IPCC Source Category 1A).⁵⁹

The emissions are reported in the Energy sector, as opposed to the IPPU sector, to reflect national circumstances in its choice of methodology and to increase transparency of this source category’s unique country-specific data sources and methodology. The country-specific methodology used for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category is based on a carbon balance (i.e., C inputs-outputs) calculation of the aggregate amount of fossil fuels used for non-energy uses, including inputs of lubricants, waxes, asphalt and road oil (see Section 3.2, Table 3-21). For those inputs, U.S. country-specific data on C stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the C stored by the fossil fuel non-energy products to the total C content of the fuel consumed, taking into account losses in the production process and during product use.⁶⁰ The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a C balance calculation, breaking out the C emissions from non-energy use of

⁵⁸ See Volume 3: Industrial Processes and Product Use, Chapter 5: Non-Energy Products from Fuels and Solvent Use of the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

⁵⁹ Non-methane volatile organic compound (NMVOC) emissions from solvent use are reported separately in the IPPU sector, following Chapter 5 of the *2006 IPCC Guidelines*.

⁶⁰ Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3: Methodology and Data for Estimating CO₂ Emissions from Fossil Fuel Combustion.

lubricants, waxes, and asphalt and road oil. Due to U.S. national circumstances, reporting these C emissions separately under IPPU would involve making artificial adjustments to both the C inputs and C outputs of the non-energy use C balance. These artificial adjustments would also result in the C emissions for lubricants, waxes, and asphalt and road oil being reported under IPPU, while the C storage for lubricants, waxes, and asphalt and road oil would be reported under Energy. To avoid presenting an incomplete C balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of C storage and C emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the C storage and C emissions for lubricants, waxes, and asphalt and road oil are reported under the Energy sector.

3.3 Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000; Goldstein and Madtes 2001; Kaufman et al. 2004; Simmons et al. 2006; van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as scrap tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, scrap tires are combusted for energy recovery in industrial and utility boilers, pulp and paper mills, and cement kilns. Incineration of waste results in conversion of the organic inputs to CO₂. According to IPCC guidelines, when the CO₂ emitted is of fossil origin, it is counted as a net anthropogenic emission of CO₂ to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black in scrap tires—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. As noted above, scrap tires (which contain synthetic rubber and carbon black) are also considered a “non-hazardous” waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the C mass balance for non-energy uses of fossil fuels.

Approximately 29.6 million metric tons of MSW were incinerated in the United States in 2013 (EPA 2015). Data for the amount of MSW incinerated in 2014 were not available, so data for 2014 was assumed to be equal to data for 2013. CO₂ emissions from incineration of waste rose 18 percent since 1990, to an estimated 9.4 MMT CO₂ Eq. (9,421 kt) in 2014, as the volume of scrap tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of CH₄ and N₂O emissions (De Soete 1993; IPCC 2006). Methane emissions from the incineration of waste were estimated to be less than 0.05 MMT CO₂ Eq. (less than 0.5 kt CH₄) in 2014, and have not changed significantly since 1990. Nitrous oxide emissions from the incineration of waste were estimated to be 0.3 MMT CO₂ Eq. (1 kt N₂O) in 2014, and have not changed significantly since 1990.

Table 3-24: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (MMT CO₂ Eq.)

Gas/Waste Product	1990	2005	2010	2011	2012	2013	2014 ^a
CO ₂	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Plastics	5.6	6.9	6.0	5.8	5.7	4.9	4.9
Synthetic Rubber in Tires	0.3	1.6	1.5	1.4	1.3	1.2	1.2

Carbon Black in Tires	0.4	2.0	1.8	1.7	1.5	1.4	1.4
Synthetic Rubber in MSW	0.9	0.8	0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8	1.2	1.1	1.1	1.1	1.3	1.3
CH₄	+	+	+	+	+	+	+
N₂O	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Total	8.4	12.8	11.4	10.9	10.7	9.7	9.7

^a Set equal to 2013 value.

Table 3-25: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (kt)

Gas/Waste Product	1990	2005	2010	2011	2012	2013	2014 ^a
CO₂	7,972	12,454	11,026	10,550	10,362	9,421	9,421
Plastics	5,588	6,919	5,969	5,757	5,709	4,857	4,857
Synthetic Rubber in Tires	308	1,599	1,461	1,363	1,262	1,158	1,158
Carbon Black in Tires	385	1,958	1,783	1,663	1,537	1,412	1,412
Synthetic Rubber in MSW	854	765	701	712	705	729	729
Synthetic Fibers	838	1,212	1,112	1,056	1,149	1,265	1,265
CH₄	+	+	+	+	+	+	+
N₂O	2	1	1	1	1	1	1

^a Set equal to 2013 value.

Methodology

Emissions of CO₂ from the incineration of waste include CO₂ generated by the incineration of plastics, synthetic fibers, and synthetic rubber in MSW, as well as the incineration of synthetic rubber and carbon black in scrap tires. These emissions were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO₂ were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of scrap tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.7.

For each of the methods used to calculate CO₂ emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers in MSW, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 2000 through 2003, 2005 through 2014), *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2014, the amount of MSW incinerated was assumed to be equal to that in 2013, due to the lack of available data. The proportion of total waste discarded that is incinerated was derived from Shin (2014). Data on total waste incinerated was not available for 2012 through 2014, so these values were assumed to equal to the 2011 value. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Management Summary for 2005 through 2013 data (RMA 2014). Average C contents for the “Other” plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: C content for 1990 through 1998 is based on the 1998 value; C content for 1999 through 2001 is the average of 1998 and 2002 values; and C content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers’ Association internet site (RMA 2012a).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO₂ emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of CH₄ and N₂O. These emissions were calculated as a function of the total estimated mass of waste incinerated and emission factors. As noted above, CH₄ and N₂O emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in *BioCycle* (van Haaren et al. 2010). Data for 2009 and 2010 were interpolated between 2008 and 2011 values. Data for 2011 were derived from Shin (2014). Data on total waste incinerated was not available in the *BioCycle* data set for 2012 through 2014, so these values were assumed to equal the 2011 *Biocycle* data set value.

Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. The emission factors of N₂O and CH₄ emissions per quantity of municipal solid waste combusted are default emission factors for the default continuously-fed stoker unit MSW incineration technology type and were taken from IPCC (2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted (BioCycle data set)

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0%
2005	259,559,787	25,973,520	10.0%
2010	271,592,991	22,714,122	8.0%
2011	273,116,704	20,756,870	7.6%
2012	273,116,704 ^a	20,756,870	7.6%
2013	273,116,704 ^a	20,756,870	7.6%
2014	273,116,704 ^a	20,756,870	7.6%

^a Assumed equal to 2011 value.

Source: van Haaren et al. (2010)

Uncertainty and Time-Series Consistency

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO₂ emissions and N₂O emissions from the incineration of waste (given the very low emissions for CH₄, no uncertainty estimate was derived). IPCC Approach 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N₂O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-27. Waste incineration CO₂ emissions in 2014 were estimated to be between 8.5 and 11.5 MMT CO₂ Eq. at a 95 percent confidence level.

This indicates a range of 10 percent below to 14 percent above the 2014 emission estimate of 9.4 MMT CO₂ Eq. Also at a 95 percent confidence level, waste incineration N₂O emissions in 2014 were estimated to be between 0.1 and 0.8 MMT CO₂ Eq. This indicates a range of 53 percent below to 163 percent above the 2014 emission estimate of 0.3 MMT CO₂ Eq.

Table 3-27: Approach 2 Quantitative Uncertainty Estimates for CO₂ and N₂O from the Incineration of Waste (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO ₂	9.4	8.5	11.5	-10%	+14%
Incineration of Waste	N ₂ O	0.3	0.1	0.8	-53%	+163%

^a Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control plan was implemented for incineration of waste. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

For the current Inventory, emission estimates for 2013 have been updated based on *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015).

The data which calculates the percent incineration was updated in the current Inventory. *Biocycle* has not released a new State of Garbage in America Report since 2010 (with 2008 data), which used to be a semi-annual publication which publishes the results of the nation-wide MSW survey. The results of the survey have been published in Shin 2014. This provided updated incineration data for 2011, so the generation and incineration data for 2012 through 2014 are assumed equivalent to the 2011 values. The data for 2009 and 2010 were based on interpolations between 2008 and 2011.

Planned Improvements

The availability of facility-level waste incineration data through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize waste incineration operations in the United States. This characterization could include future improvements as to the operations involved in waste incineration for energy, whether in the power generation sector or the industrial sector. Additional examinations will be necessary as, unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,⁶¹ some facility-level waste incineration emissions reported under EPA's GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, emissions for waste incineration with energy recovery are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In

⁶¹ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

examining data from EPA's GHGRP that would be useful to improve the emission estimates for the waste incineration category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on ensuring CO₂ emissions from the biomass component of waste are separated in the facility-level reported data, and on maintaining consistency with national waste generation and fate statistics currently used to estimate total, national U.S. greenhouse gas emissions. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁶² GHGRP data is available for MSW combustors, which contains information on the CO₂, CH₄, and N₂O emissions from MSW combustion, plus the fraction of the emissions that are biogenic. To calculate biogenic versus total CO₂ emissions, a default biogenic fraction of 0.6 is used. The biogenic fraction will be calculated using the current input data and assumptions to verify the current MSW emission estimates.

If GHGRP data would not provide a more accurate estimate of the amount of solid waste combusted, new data sources for the total MSW generated will be explored given that the data previously published semi-annually in Biocycle (van Haaren et al. 2010) has ceased to be published, according to the authors. Equivalent data was derived from Shin (2014) for 2011. A new methodology would be developed based on the available data within the annual update of EPA's *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015). In developing the new methodology, appropriate assumptions would need to be made to ensure that the MSW figures included all waste. Additionally, the carbon content of the synthetic fiber will be updated based on each year's production mix.

Additional improvements will be conducted to improve the transparency in the current reporting of waste incineration. Currently, hazardous industrial waste incineration is included within the overall calculations for the Carbon Emitted from Non-Energy Uses of Fossil Fuels category. Waste incineration activities that do not include energy recovery will be examined. Synthetic fibers within scrap tires are not included in this analysis and will be explored for future inventories. The carbon content of fibers within scrap tires would be used to calculate the associated incineration emissions. Updated fiber content data from the Fiber Economics Bureau will also be explored.

3.4 Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining-related activities release CH₄ to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface mines account for the majority of U.S. coal production, underground coal mines contribute the largest share of CH₄ emissions (see Table 3-29 and Table 3-30) due to the higher CH₄ content of coal in the deeper underground coal seams. In 2014, 345 underground coal mines and 613 surface mines were operating in the United States. In recent years the total number of active coal mines in the United States has declined. In 2014, the United States was the second largest coal producer in the world (906 MMT), after China (3,650 MMT) and followed by India (668 MMT) (IEA 2015).

Table 3-28: Coal Production (kt)

Year	Underground		Surface		Total	
	Number of Mines	Production	Number of Mines	Production	Number of Mines	Production
1990	1,683	384,244	1,656	546,808	3,339	931,052
2005	586	334,398	789	691,448	1,398	1,025,846
2010	497	305,862	760	676,177	1,257	982,039
2011	508	313,529	788	684,807	1,296	998,337
2012	488	310,608	719	610,307	1,207	920,915
2013	395	309,546	637	581,270	1,032	890,815
2014	345	321,783	613	583,974	958	905,757

⁶² See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

Underground mines liberate CH₄ from ventilation systems and from degasification systems. Ventilation systems pump air through the mine workings to dilute noxious gases and ensure worker safety; these systems can exhaust significant amounts of CH₄ to the atmosphere in low concentrations. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large, often highly concentrated volumes of CH₄ before, during, or after mining. Some mines recover and use CH₄ generated from ventilation and degasification systems, thereby reducing emissions to the atmosphere.

Surface coal mines liberate CH₄ as the overburden is removed and the coal is exposed to the atmosphere. CH₄ emissions are normally a function of coal rank (a classification related to the percentage of carbon in the coal) and depth. Surface coal mines typically produce lower-rank coals and remove less than 250 feet of overburden, so their level of emissions is much lower than from underground mines.

In addition, CH₄ is released during post-mining activities, as the coal is processed, transported, and stored for use.

Total CH₄ emissions in 2014 were estimated to be 2,703 kt (67.6 MMT CO₂ eq.), a decline of 30 percent since 1990 (see Table 3-29 and Table 3-30). Of this amount, underground mines accounted for approximately 73 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 13 percent.

Table 3-29: CH₄ Emissions from Coal Mining (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Underground (UG) Mining	74.2	42.0	61.6	50.2	47.3	46.2	49.1
Liberated	80.8	59.7	85.2	71.0	65.8	65.8	65.7
Recovered & Used	(6.6)	(17.7)	(23.6)	(20.8)	(18.5)	(19.6)	(16.6)
Surface Mining	10.8	11.9	11.5	11.6	10.3	9.7	9.6
Post-Mining (UG)	9.2	7.6	6.8	6.9	6.7	6.6	6.7
Post-Mining (Surface)	2.3	2.6	2.5	2.5	2.2	2.1	2.1
Total	96.5	64.1	82.3	71.2	66.5	64.6	67.6

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-30: CH₄ Emissions from Coal Mining (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
UG Mining	2,968	1,682	2,463	2,008	1,891	1,849	1,964
Liberated	3,234	2,390	3,406	2,839	2,631	2,633	2,627
Recovered & Used	(266)	(708)	(943)	(831)	(740)	(784)	(662)
Surface Mining	430	475	461	465	410	388	386
Post-Mining (UG)	368	306	270	276	268	263	270
Post-Mining (Surface)	93	103	100	101	89	84	84
Total	3,860	2,565	3,293	2,849	2,658	2,584	2,703

Notes: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH₄ emissions from coal mining consists of two steps:

- Estimate emissions from underground mines. These emissions have two sources: ventilation systems and degasification systems. They are estimated on a mine-by-mine basis, then summed to determine total CH₄ liberated. The CH₄ recovered and used is then subtracted from this total, resulting in an estimate of net emissions to the atmosphere.
- Estimate CH₄ emissions from surface mines and post-mining activities. Unlike the methodology for underground mines, which uses mine-specific data, the methodology for estimating emissions from surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-specific gas content and an emission factor.

Step 1: Estimate CH₄ Liberated and CH₄ Emitted from Underground Mines

Underground mines generate CH₄ from ventilation systems and from degasification systems. Some mines recover and use the generated CH₄, thereby reducing emissions to the atmosphere. Total CH₄ emitted from underground mines equals the CH₄ liberated from ventilation systems, plus the CH₄ liberated from degasification systems, minus the CH₄ recovered and used.

Step 1.1: Estimate CH₄ Liberated from Ventilation Systems

To estimate CH₄ liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting Program (GHGRP) (subpart FF, “Underground Coal Mines”), data provided by the U.S. Mine Safety and Health Administration (MSHA), and occasionally data collected from other sources on a site-specific level (e.g., state data). Since 2011, the nation’s “gassiest” underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH₄ per year (about 14,700 MT CO₂ eq.)—have been required to report to EPA’s GHGRP (EPA 2015).⁶³ Mines that report to the GHGRP must report quarterly measurements of CH₄ emissions from ventilation systems to EPA; they have the option of recording their own measurements, or using the measurements taken by MSHA as part of that agency’s quarterly safety inspections of all mines in the United States with detectable CH₄ concentrations.⁶⁴

Since 2013, ventilation emission estimates have been calculated based on both GHGRP data submitted by underground mines that recorded their own measurements, and on quarterly measurement data obtained directly from MSHA for the remaining mines (not MSHA data reported by the mines to the GHGRP).⁶⁵ The quarterly measurements are used to determine the average daily emissions rate for the reporting year quarter.

Step 1.2: Estimate CH₄ Liberated from Degasification Systems

Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to remove CH₄ before, during, or after mining. This CH₄ can then be collected for use or vented to the atmosphere. Twenty-five mines used degasification systems in 2014, and the CH₄ removed through these systems was reported to EPA’s GHGRP (EPA 2015). Based on the weekly measurements reported to EPA’s GHGRP, degasification data summaries for each mine were added together to estimate the CH₄ liberated from degasification systems. Sixteen of the 25 mines with degasification systems had operational CH₄ recovery and use projects (see step 1.3 below), and GHGRP reports show the remaining nine mines vented CH₄ from degasification systems to the atmosphere.⁶⁶

Degasification volumes for the life of any pre-mining wells are attributed to the mine as emissions in the year in which the well is mined through.⁶⁷ EPA’s GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under subpart FF. Most pre-mining wells drilled from the surface are considered coalbed methane wells and are reported under another subpart of the program (subpart W, “Petroleum and Natural Gas Systems”). As a result, for the 10 mines with degasification systems that include pre-mining wells, GHGRP information was supplemented with historical data from state gas well production databases (GSA 2016, WVGES 2015), as well as with mine-specific information regarding the dates on which the pre-mining wells are mined through (JWR 2010, El Paso 2009).

Degasification information reported to EPA’s GHGRP by underground coal mines was the primary source of data used to develop estimates of CH₄ liberated from degasification systems. Data reported to EPA’s GHGRP were used to estimate CH₄ liberated from degasification systems at 20 of the 25 mines that employed degasification systems in 2014. For the other five mines (all with pre-mining wells from which CH₄ was recovered), GHGRP data—along with supplemental information from state gas production databases (GSA 2016, WVGES 2015)—were used to

⁶³ Underground coal mines report to EPA under Subpart FF of the GHGRP. In 2014, 128 underground coal mines reported to the program.

⁶⁴ MSHA records coal mine CH₄ readings with concentrations of greater than 50 ppm (parts per million) CH₄. Readings below this threshold are considered non-detectable.

⁶⁵ EPA has determined that certain mines are having difficulty interpreting the MSHA data so that they report them correctly to the GHGRP. EPA is working with these mines to correct their GHGRP reports, and in the meantime is relying on data obtained directly from MSHA for purposes of the national inventory.

⁶⁶ Several of the mines venting CH₄ from degasification systems use a small portion the gas to fuel gob well blowers in remote locations where electricity is not available. However, this CH₄ use is not considered to be a formal recovery and use project.

⁶⁷ A well is “mined through” when coal mining development or the working face intersects the borehole or well.

estimate CH₄ liberated from degasification systems. For one mine, due to a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the CH₄ liberated was based on both the reported GHGRP data (for the vented portion of CH₄ recovered) and an estimate from historical mine-provided CH₄ recovery and use rates based on gas sales records (JWR 2010, El Paso 2009).

Step 1.3: Estimate CH₄ Recovered from Ventilation and Degasification Systems, and Utilized or Destroyed (Emissions Avoided)

Sixteen mines had CH₄ recovery and use projects in place in 2014. Fourteen of these mines sold the recovered CH₄ to a pipeline, including one that also used CH₄ to fuel a thermal coal dryer. In addition, one mine used recovered CH₄ for electrical power generation, and one used recovered CH₄ to heat mine ventilation air.

Ten of the 16 mines deployed degasification systems in 2014; for those mines, estimates of CH₄ recovered from the systems were exclusively based on GHGRP data. Based on weekly measurements, the GHGRP degasification destruction data summaries for each mine were added together to estimate the CH₄ recovered and used from degasification systems.

All 10 mines with degasification systems used pre-mining wells as part of those systems, but only four of them intersected pre-mining wells in 2014. GHGRP and supplemental data were used to estimate CH₄ recovered and used at two of these four mines; supplemental data alone (GSA 2016) were used for the other two mines, which reported to EPA's GHGRP as a single entity. Supplemental information was used for these four mines because estimating CH₄ recovery and use from pre-mining wells requires additional data (not reported under subpart FF of EPA's GHGRP, see discussion in step 1.2 above) to account for the emissions avoided. The supplemental data came from state gas production databases, as well as mine-specific information on the timing of mined-through pre-mining wells.

GHGRP information was not used to estimate CH₄ recovered and used at two mines. At one of these mines, a portion (16 percent) of reported CH₄ vented was applied to an ongoing mine air heating project. Because of a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the 2014 CH₄ recovered and used at the other mine was based on an estimate from historical mine-provided CH₄ recovery and use rates (including emissions avoided from pre-mining wells).

In 2014, one mine destroyed a portion of its CH₄ emissions from ventilation systems using thermal oxidation technology. The amount of CH₄ recovered and destroyed by the project was determined through publicly-available emission reduction project information (CAR 2015).

Step 2: Estimate CH₄ Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH₄ emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration's Annual Coal Report (EIA 2015) was multiplied by basin-specific CH₄ contents (EPA 1996, 2005) and a 150 percent emission factor (to account for CH₄ from over- and under-burden) to estimate CH₄ emissions (see King 1994, Saghaifi 2013). For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a mid-range 32.5 percent emission factor for CH₄ desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data were compiled from AAPG (1984) and USBM (1986).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data from EPA's GHGRP or from MSHA, uncertainty is relatively low. A degree of imprecision was introduced because the ventilation air measurements used were not continuous but rather quarterly instantaneous readings that were used to determine the average daily emissions rate for the quarter. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH₄ emissions (Mutmansky & Wang 2000). GHGRP data were used for a significant number of the mines that reported their own measurements to the program beginning in 2013; however, the equipment uncertainty is applied to both GHGRP and MSHA data.

Estimates of CH₄ recovered by degasification systems are relatively certain for utilized CH₄ because of the availability of GHGRP data and gas sales information. Many of the recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than estimated.

EPA's GHGRP requires weekly CH₄ monitoring of mines that report degasification systems, and continuous CH₄ monitoring is required for utilized CH₄ on- or off-site. Since 2012, GHGRP data have been used to estimate CH₄ emissions from vented degasification wells, reducing the uncertainty associated with prior MSHA estimates used for this subsource. Beginning in 2013, GHGRP data were also used for determining CH₄ recovery and use at mines without publicly available gas usage or sales records, which has reduced the uncertainty from previous estimation methods that were based on information from coal industry contacts.

Surface mining and post-mining emissions are associated with considerably more uncertainty than underground mines, because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions constitute the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH₄ emissions in 2014 were estimated to be between 59.9 and 77.4 MMT CO₂ eq. at a 95 percent confidence level. This indicates a range of 11.9 percent below to 15.3 percent above the 2014 emission estimate of 67.6 MMT CO₂ eq.

Table 3-31: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Coal Mining (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal mining	CH ₄	67.6	59.9	77.4	-11.9%	+15.3%

^a Range of emission estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval.

Note: Emissions values are presented in CO₂ equivalent mass units using IPCC AR4 GWP values.

Methodological recalculations were applied to the entire time-series to ensure consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the methodology section.

Recalculations Discussion

For the current Inventory, no recalculations were performed on prior inventory years.

Planned Improvements

Future improvements to the coal mining category will include continued analysis and integration into the national inventory of the degasification quantities and ventilation emissions data reported by underground coal mines to EPA's GHGRP. A higher reliance on EPA's GHGRP will provide greater consistency and accuracy in future inventories. MSHA data will serve as a quality assurance tool for validating GHGRP data. Reconciliation of the GHGRP and Inventory data sets is still in progress. In implementing improvements and integrating data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied on (IPCC 2011).

3.5 Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of coal mine methane (CMM) emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH₄ after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH₄ that may find its way to surface structures through overburden fractures. As work stops within the mines, CH₄ liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH₄ at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH₄ migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH₄ flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Annual gross abandoned mine CH₄ emissions ranged from 7.2 to 10.8 MMT CO₂ Eq. from 1990 through 2014, varying, in general, by less than 1 percent to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (10.8 MMT CO₂ Eq.) due to the large number of gassy mine⁶⁸ closures from 1994 to 1996 (72 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. Since 2002, there have been fewer than twelve gassy mine closures each year. There were seven gassy mine closures in 2014. In 2014, gross abandoned mine emissions decreased slightly to 8.7 MMT CO₂ Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH₄ recovered and used at 37 mines, resulting in net emissions in 2014 of 6.3 MMT CO₂ Eq.

Table 3-32: CH₄ Emissions from Abandoned Coal Mines (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Abandoned Underground Mines	7.2	8.4	9.7	9.3	8.9	8.8	8.7
Recovered & Used	+	1.8	3.2	2.9	2.7	2.6	2.4
Total	7.2	6.6	6.6	6.4	6.2	6.2	6.3

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

⁶⁸ A mine is considered a “gassy” mine if it emits more than 100 thousand cubic feet of CH₄ per day (100 mcf/d).

Table 3-33: CH₄ Emissions from Abandoned Coal Mines (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Abandoned Underground Mines	288	334	389	373	358	353	350
Recovered & Used	+	70	126	116	109	104	97
Total	288	264	263	257	249	249	253

+ Does not exceed 0.5 kt

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH₄ emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH₄ from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH₄ emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH₄ emissions over time for a given abandoned mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH₄ leaves the system, the reservoir pressure (Pr) declines as described by the isotherm's characteristics. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure for a vented mine, and the productivity index (PI), which is expressed as the flow rate per unit of pressure change, is essentially constant at the pressures of interest (atmospheric to 30 psia). The CH₄ flow rate is determined by the laws of gas flow through porous media, such as Darcy's Law. A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i (1 + bD_i t)^{(-1/b)}$$

where,

- q = Gas flow rate at time t in million cubic feet per day (mmcf/d)
- q_i = Initial gas flow rate at time zero (t₀), mmcf/d
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t₀ (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2004).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emissions after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore will no longer have any measurable CH₄ emissions. Based on this assumption, an average decline rate for flooded mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2004).

$$q = q_i e^{(-Dt)}$$

where,

- q = Gas flow rate at time t in mmcf/d
 q_i = Initial gas flow rate at time zero (t_0), mmcf/d
 D = Decline rate, 1/yr
 t = Elapsed time from t_0 (years)

Seals have an inhibiting effect on the rate of flow of CH₄ into the atmosphere compared to the flow rate that would exist if the mine had an open vent. The total volume emitted will be the same, but emissions will occur over a longer period of time. The methodology, therefore, treats the emissions prediction from a sealed mine similarly to the emissions prediction from a vented mine, but uses a lower initial rate depending on the degree of sealing. A computational fluid dynamics simulator was used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 - [\text{initial emissions from sealed mine} / \text{emission rate at abandonment prior to sealing}])$. Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2004).

For active coal mines, those mines producing over 100 thousand cubic feet per day (mcf/d) account for 98 percent of all CH₄ emissions. This same relationship is assumed for abandoned mines. It was determined that the 500 abandoned mines closed after 1972 produced emissions greater than 100 mcf/d when active. Further, the status of 291 of the 500 mines (or 58 percent) is known to be either: 1) vented to the atmosphere; 2) sealed to some degree (either earthen or concrete seals); or, 3) flooded (enough to inhibit CH₄ flow to the atmosphere). The remaining 42 percent of the mines whose status is unknown were placed in one of these three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2004).

Table 3-34: Number of Gassy Abandoned Mines Present in U.S. Basins in 2014, grouped by Class according to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	37	25	51	113	137	250
Illinois	32	3	14	49	27	76
Northern Appl.	43	22	16	81	36	117
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	139	53	99	291	209	500

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1971; however, such data are largely unknown for mines closed before 1972. Information that is readily available, such as coal production by state and county, is helpful but does not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned before 1972. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1971 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH₄ emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to the 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH₄ emissions rates during the 1970s (EPA 2004).

Abandoned mine emission estimates are based on all closed mines known to have active mine CH₄ ventilation emission rates greater than 100 mcf/d at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database (MSHA 2015). Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH₄ degasification amounts were added to the quantity of CH₄ vented to determine the total CH₄ liberation rate for all mines that closed between 1992 and 2014. Since the sample of gassy mines is assumed to

account for 78 percent of the pre-1972 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2014, emission totals were downwardly adjusted to reflect abandoned mine CH₄ emissions avoided from those mines. The Inventory totals were not adjusted for abandoned mine reductions from 1990 through 1992 because no data was reported for abandoned coal mining CH₄ recovery projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH₄ flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but rather values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-35. Annual abandoned coal mine CH₄ emissions in 2014 were estimated to be between 5.2 and 7.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 18 percent below to 24 percent above the 2014 emission estimate of 6.3 MMT CO₂ Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the methodology for mines closed after 1972. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH₄ liberation rates exist.

Table 3-35: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Abandoned Underground Coal Mines (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH ₄	6.3	5.2	7.9	-18%	+24%

^a Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.6 Petroleum Systems (IPCC Source Category 1B2a)

Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil production, transportation, and refining operations. During these activities, CH₄ is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO₂ emissions from petroleum systems are primarily associated with crude oil production and refining

operations but are negligible in transportation operations. Total CH₄ emissions from petroleum systems in 2014 were 68.1 MMT CO₂ Eq. (2,726 kt).

Production Field Operations. Production field operations account for approximately 99 percent of total CH₄ emissions from petroleum systems. Vented CH₄ from field operations account for approximately 92 percent of the net emissions from the production sector, fugitive emissions are approximately 5 percent, uncombusted CH₄ emissions (i.e., unburned fuel) account for approximately 4 percent, and process upset emissions are 0.1 percent. The most dominant sources of emissions from production field operations are pneumatic controllers, oil tanks, chemical injection pumps, offshore oil platforms, hydraulic fractured oil well completions, gas engines, and oil wellheads. These sources alone emit over 95 percent of the production field operations emissions. The remaining 5 percent of the emissions are distributed among around 20 additional activities.

Since 1990, CH₄ emissions from production field operations have increased by nearly 80 percent. Total methane emissions (from all segments) have increased by around 5 percent from 2013 levels.

Vented CO₂ associated with production field operations account for approximately 99 percent of the total CO₂ emissions from production field operations, while fugitive and process upsets together account for approximately 1 percent of the emissions. The most dominant sources of CO₂ emissions are oil tanks, pneumatic controllers, chemical injection pumps, and offshore oil platforms. These five sources together account for slightly over 97 percent of the non-combustion CO₂ emissions from production field operations, while the remaining 3 percent of the emissions is distributed among around 20 additional activities. Note that CO₂ from associated gas flaring is accounted in natural gas systems production emissions. Total CO₂ emissions from flaring for both natural gas and oil were 20.8 MMT CO₂ Eq. in 2014.

Crude Oil Transportation. Crude oil transportation activities account for approximately 0.3 percent of total CH₄ emissions from the oil industry. Venting from tanks, truck loading, rail loading, and marine vessel loading operations account for 84 percent of CH₄ emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for approximately 12 percent of CH₄ emissions from crude oil transportation. The remaining 4 percent is distributed between two additional sources within the vented emissions category (i.e., pump station maintenance and pipeline pigging), and fugitive emissions from pump stations.

Since 1990, CH₄ emissions from transportation have increased by almost 24 percent. However, because emissions from crude oil transportation account for such a small percentage of the total emissions from the petroleum industry, this has had little impact on the overall emissions. Methane emissions from transportation have increased by approximately 13 percent from 2013 levels.

Crude Oil Refining. Crude oil refining processes and systems account for approximately 1 percent of total CH₄ emissions from the oil industry because most of the CH₄ in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH₄ in all refined products. Within refineries, combustion emissions account for slightly over 50 percent of the CH₄ emissions, while vented and fugitive emissions account for approximately 31 and 19 percent, respectively. Flare emissions are the primary combustion emissions contributor, accounting for approximately 79 percent of combustion CH₄ emissions. Refinery system blowdowns for maintenance and process vents are the primary venting contributors (96 percent). Most of the fugitive CH₄ emissions from refineries are from equipment leaks and storage tanks (89 percent).

Methane emissions from refining of crude oil have decreased by approximately 1.4 percent since 1990; however, similar to the transportation subcategory, this decrease has had little effect on the overall emissions of CH₄. Since 1990, CH₄ emissions from crude oil refining have fluctuated between 23 and 28 kt.

Flare emissions from crude oil refining accounts for slightly more than 94 percent of the total CO₂ emissions in petroleum systems. Refinery CO₂ emissions decreased by slightly more than 7 percent from 1990 to 2014.

Table 3-36: CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations							
(Potential)	38.0	48.9	54.8	56.6	58.7	64.7	68.1
Pneumatic controller venting ^a	19.0	30.2	33.2	33.7	33.3	37.7	39.2
Tank venting	6.3	4.7	5.3	5.5	7.0	8.2	9.9
Combustion & process upsets	2.9	2.3	2.5	2.5	2.7	2.9	3.1
Misc. venting & fugitives	8.4	10.5	12.5	13.5	14.3	14.3	14.5

Wellhead fugitives	1.5	1.2	1.4	1.4	1.5	1.5	1.5
Production Voluntary Reductions	(0.0)	(0.9)	(1.5)	(1.1)	(1.1)	(0.8)	(0.8)
Production Field Operations (Net)	38.0	48.0	53.3	55.4	57.5	63.9	67.4
Crude Oil Transportation	0.2	0.1	0.1	0.1	0.2	0.2	0.2
Refining	0.6	0.7	0.6	0.7	0.7	0.6	0.6
Total	38.7	48.8	54.1	56.3	58.4	64.7	68.1

^a Values presented in this table for pneumatic controllers are net emissions. The revised methodology for the 2016 (current) Inventory incorporates GHGRP subpart W activity and emissions data, and is detailed in the Recalculations Discussion section.

Notes: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table 3-37: CH₄ Emissions from Petroleum Systems (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations (Potential)	1,519	1,957	2,193	2,263	2,347	2,586	2,725
Pneumatic controller venting ^a	761	1,209	1,328	1,346	1,332	1,509	1,567
Tank venting	250	188	210	220	278	330	396
Combustion & process upsets	115	91	98	101	108	114	122
Misc. venting & fugitives	334	421	502	540	570	573	578
Wellhead fugitives	59	48	54	56	59	60	62
Production Voluntary Reductions	(0)	(36)	(60)	(45)	(45)	(31)	(31)
Production Field Operations (Net)	1,519	1,921	2,133	2,218	2,302	2,556	2,694
Crude Oil Transportation	7	5	5	5	6	7	8
Refining	24	27	26	28	27	26	23
Total	1,550	1,953	2,163	2,251	2,335	2,588	2,726

^a Values presented in this table for pneumatic controllers are net emissions. The revised methodology for the 2016 (current) Inventory incorporates GHGRP subpart W activity and emissions data, and is detailed in the Recalculations Discussion section.

Notes: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table 3-38: CO₂ Emissions from Petroleum Systems (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations	0.4	0.3	0.4	0.4	0.5	0.6	0.6
Pneumatic controller venting	+	0.1	0.1	0.1	0.1	0.1	0.1
Tank venting	0.3	0.2	0.3	0.3	0.4	0.4	0.5
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Process upsets	+	+	+	+	+	+	+
Crude Refining	3.2	3.6	3.8	3.8	3.4	3.1	2.9
Total	3.6	3.9	4.2	4.2	3.9	3.7	3.6

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-39: CO₂ Emissions from Petroleum Systems (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations	391	338	379	395	473	550	640
Pneumatic controller venting	42	67	74	75	74	84	87
Tank venting	328	246	276	288	365	432	519
Misc. venting & fugitives	17	21	26	28	30	30	30
Wellhead fugitives	3	3	3	3	3	3	3
Process upsets	0.2	0.1	0.2	0.2	0.2	0.2	0.2
Crude Refining	3,162	3,589	3,775	3,797	3,404	3,143	2,927
Total	3,553	3,927	4,154	4,192	3,876	3,693	3,567

Note: Totals may not sum due to independent rounding.

Methodology

The estimates of CH₄ emissions from petroleum systems are largely based on GRI/EPA 1996, EPA 1999, and EPA's GHGRP data (EPA 2015a). Petroleum Systems includes emission estimates for activities occurring in petroleum systems from the oil wellhead through crude oil refining, including activities for crude oil production field operations, crude oil transportation activities, and refining operations. Annex 3.5 provides detail on the emission estimates for these activities. The estimates of CH₄ emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment or per activity) by the corresponding activity data (e.g., equipment count or frequency of activity).

References for emission factors include DrillingInfo (2015), "Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA" (EPA/GRI 1996a-d), "Estimates of Methane Emissions from the U.S. Oil Industry" (EPA 1999), consensus of industry peer review panels, BOEMRE and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), and the GHGRP (2010 through 2014).

Emission factors from EPA 1999 are used for all activities except those related to pneumatic controllers, chemical injection pumps, hydraulic fractured oil well completions, offshore oil production, field storage tanks, and refineries. The emission factors for pneumatic controllers venting and chemical injection pumps were developed using EPA's GHGRP data for reporting year 2014. Emission factors for hydraulically fractured (HF) oil well completions (controlled and uncontrolled) were developed using data analyzed for the 2015 NSPS OOOOa proposal (EPA 2015b). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2011). For offshore oil production, two emission factors were calculated using data collected for all federal offshore platforms (EPA 2015c, BOEM 2014), one for oil platforms in shallow water, and one for oil platforms in deep water. For all sources, emission factors are held constant for the period 1990 through 2014.

References for activity data include DrillingInfo (2015), the Energy Information Administration annual and monthly reports (EIA 1990 through 2015), (EIA 1995 through 2015a, 2015b), "Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA" (EPA/GRI 1996a-d), "Estimates of Methane Emissions from the U.S. Oil Industry" (EPA 1999), consensus of industry peer review panels, BOEMRE and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2015), the Interstate Oil and Gas Compact Commission (IOGCC 2012), the United States Army Corps of Engineers, (1995 through 2015), and the GHGRP (2010 through 2014).

For many sources, complete activity data were not available for all years of the time series. In such cases, one of three approaches was employed. Where appropriate, the activity data were calculated from related statistics using ratios developed based on EPA 1996, and/or GHGRP data. In other cases, the activity data were held constant from 1990 through 2014 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. For offshore production, the number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from Bureau of Ocean Energy Management (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) datasets (BOEM 2011a,b,c).

For petroleum refining activities, 2010 to 2014 emissions were directly obtained from EPA's GHGRP. All refineries have been required to report CH₄ and CO₂ emissions for all major activities since 2010. The national totals of these emissions for each activity were used for the 2010 to 2014 emissions. The national emission totals for each activity were divided by refinery feed rates for those four Inventory years to develop average activity-specific emission factors, which were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for each year (EPA 2015d).

The Inventory estimate for Petroleum Systems takes into account Natural Gas STAR reductions. Voluntary reductions included in the Petroleum Systems calculations were those reported to Natural Gas STAR for the following activities: artificial lift - gas lift; artificial lift - use compression; artificial lift - use pumping unit; consolidate crude oil production and water storage tanks; lower heater-treater temperature; re-inject gas for enhanced oil recovery; re-inject gas into crude; and route casinghead gas to vapor recovery unit or compressor.

The methodology for estimating CO₂ emissions from petroleum systems includes calculation of vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and three activities from petroleum refining. Generally, emissions are estimated for each activity by multiplying CO₂ emission factors by their corresponding activity data. The emission factors for CO₂ are generally estimated by multiplying the CH₄ emission factors by a conversion factor, which is the ratio of CO₂ content and CH₄ content in produced associated gas. One exception to this methodology is the set of emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factors for offshore oil production (shallow and deep water), which were derived using data from BOEM (EPA 2015c, BOEM 2014). Other exceptions to this methodology are the three petroleum refining activities (i.e., flares, asphalt blowing, and process vents); the CO₂ emissions data for 2010 to 2014 were directly obtained from the GHGRP. The 2010 to 2013 CO₂ emissions data from GHGRP along with the refinery feed data for 2010 to 2013 were used to derive CO₂ emission factors (i.e., sum of activity emissions/sum of refinery feed) which were then applied to the annual refinery feed to estimate CO₂ emissions for 1990 to 2009.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is planning an update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information. It is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 24 percent and plus 149 percent). Details on EPA's planned uncertainty analysis are described in the Planned Improvements section.

EPA conducted a quantitative uncertainty analysis for the 2011 Inventory to determine the level of uncertainty surrounding estimates of emissions from petroleum systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emission estimates using the 7 highest-emitting sources ("top 7 sources") for the year 2010. The @RISK analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted for the 2011 Inventory has not yet been updated for the 1990 through 2014 Inventory years; instead, EPA has applied the uncertainty percentage ranges calculated previously to 2014 emission estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. However, as discussed in the Methodology and Recalculations Discussion sections, EPA has revised the methodology and data for many emission sources. Given these revisions, the 2009 uncertainty ranges applied may not reflect the uncertainty associated with the recently revised emission factors and activity data sources.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2014, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH₄ emissions in 2014 were estimated to be between 51.8 and 101.5 MMT CO₂ Eq., while CO₂ emissions were estimated to be between 2.7 and 5.4 MMT CO₂ Eq. at a 95 percent confidence level, based on previously calculated uncertainty. This indicates a range of 24 percent below to 149 percent above the 2014 emission estimates of 68.1 and 3.6 MMT CO₂ Eq. for CH₄ and CO₂, respectively.

Table 3-40: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.) (%)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH ₄	68.1	51.8	101.5	-24%	149%
Petroleum Systems	CO ₂	3.6	2.7	5.4	-24%	149%

^a Range of 2014 relative uncertainty predicted by Monte Carlo Stochastic Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.

^b All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

EPA compared the quantitative uncertainty estimate for CH₄ emissions from petroleum systems to those reported in the recently published study by Lyon et al., (2015) (see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” [EPA 2016a]).⁶⁹ Lyon et al., (2015) used the Monte Carlo simulation technique to examine uncertainty bounds for the estimates developed by that study for the Barnett Shale. The uncertainty range in the study differ from those of EPA. However, it is difficult to extrapolate an uncertainty range from this study that can be applied to the Inventory estimate because the coverage of the Lyon et al. (2015) study is limited to the 25-county Barnett Shale area, the reported estimate encompasses natural gas in addition to petroleum system emissions, and the two estimates use different methodologies and data sources.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The petroleum system emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through the annual expert and public review period. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made revisions to the production segment methodology for the 2016 (current) Inventory including revised equipment activity data, revised pneumatic controller activity and emissions data, and included a separate estimate for hydraulically fractured oil well completions, which previously were not estimated as a distinct subcategory of oil well completions.

In February 2016, the EPA released a draft memorandum, “Revisions under Consideration for Natural Gas and Petroleum Production Emissions,” that discussed the changes under consideration and requested stakeholder

⁶⁹ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

feedback on those changes. Please see <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

The combined impact of revisions to 2013 petroleum production segment emissions, compared to the 1990-2013 Inventory, is an increase in CH₄ emissions from 24.2 to 63.9 MMT CO₂ Eq. (40 MMT CO₂ Eq., or 164 percent).

The recalculations resulted in an average increase in emission estimates across the 1990 to 2013 time series, compared to the previous (2015) Inventory, of 21 MMT CO₂ Eq., or an 85 percent. The largest increases in the estimate occurred in later years of the time series.

Production

This section references the final 2016 (current) Inventory memorandum, “Revisions to Natural Gas and Petroleum Production Emissions” (EPA 2016b).⁷⁰ “Revisions to Natural Gas and Petroleum Production Emissions” contains further details and documentation of recalculations (EPA 2016b).

Updated activity factors for fugitives, pumps and controllers

Using newly available GHGRP activity data, the EPA developed activity factors (i.e., counts per oil well) for separators, headers, heater-treaters, pneumatic pumps, and pneumatic controllers. EPA reviewed this new data source and the previous data, assessed stakeholder feedback, and determined that the previous data source represents activities from the time period in which the data were collected (early 1990s) and the new GHGRP data source represents activities from recent years. The EPA applied the updated activity factors to calculate emissions from these sources for year 2011-on in the 2016 (current) Inventory petroleum production segment, while retaining the previous activity factors for 1990 through 1992. For years 1993 through 2010, the EPA calculated equipment counts by linearly interpolating between the data points of calculated national equipment counts in 1992 (based on GRI/EPA) and calculated national equipment counts in 2011 (based on GHGRP). This reflects an assumed gradual transition from the counts observed in the 1996 study and the counts observed in the recent GHGRP data.

For the year 2013, the CH₄ emissions increase due to use of revised activity factors for major equipment and pneumatic pumps is approximately 4.2 MMT CO₂ Eq.

Table 3-41: CH₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO₂ Eq.)

Type	Source	1990	2005	2010	2013	2014
Venting	Chemical Injection Pumps	1.2	3.4	4.3	4.7	4.8
	<i>Previous-Chemical</i>					
<i>Venting</i>	<i>Injection Pumps</i>	<i>1.4</i>	<i>1.2</i>	<i>1.3</i>	<i>1.4</i>	
Fugitive	Oil Wellheads	1.5	1.2	1.4	1.5	1.5
<i>Fugitive</i>	<i>Previous-Oil Wellheads</i>	<i>1.5</i>	<i>1.2</i>	<i>1.3</i>	<i>1.5</i>	
Fugitive	Separators	0.3	0.6	0.8	0.8	0.9
<i>Fugitive</i>	<i>Previous-Separators</i>	<i>0.3</i>	<i>0.2</i>	<i>0.2</i>	<i>0.3</i>	
Fugitive	Heater/Treaters	0.3	0.3	0.4	0.4	0.4
<i>Fugitive</i>	<i>Previous-Heater/Treaters</i>	<i>0.3</i>	<i>0.2</i>	<i>0.3</i>	<i>0.3</i>	
Fugitive	Headers	0.1	0.2	0.2	0.2	0.2
<i>Fugitive</i>	<i>Previous-Headers</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	
Fugitive	Compressors	0.1	+	+	0.1	0.1
<i>Fugitive</i>	<i>Previous-Compressors</i>	<i>0.1</i>	+	+	+	

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Values in *italics* are from the previous Inventory.

Using the GHGRP data, the EPA has also developed technology-specific activity data and emission factors for pneumatic controllers. Data reported under EPA’s GHGRP allow for development of emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and separation of activity data into these categories. EPA used this separation of pneumatic controller counts by bleed types and emission factors developed from reported GHGRP data. Comparing the updated 2013 estimate to the previous Inventory 2013

⁷⁰ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data is an increase of approximately 26 MMT CO₂ Eq. Over the 1990 through 2013 time series, the average increase due to the recalculation is 16 MMT CO₂ Eq.

Table 3-42: CH₄ Emissions from Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	19.0	30.2	33.2	37.7	39.2
High bleed	17.8	17.5	12.6	5.5	4.7
Low bleed	1.2	1.8	2.0	1.4	1.2
Intermittent bleed	+	10.9	18.6	30.9	33.3
<i>Previous-All</i>	<i>12.2</i>	<i>10.1</i>	<i>10.8</i>	<i>11.9</i>	<i>NA</i>
<i>Previous-High bleed</i>	<i>9.5</i>	<i>7.8</i>	<i>8.4</i>	<i>9.2</i>	<i>NA</i>
<i>Previous-Low bleed</i>	<i>2.8</i>	<i>2.3</i>	<i>2.4</i>	<i>2.7</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA's approach to revising the Inventory methodology by incorporating technology-specific GHGRP data for pneumatic controllers resulted in net emissions being directly calculated for these sources in each time series year. This methodology revision obviates the need to apply Gas STAR reductions data for pneumatic controllers as had been done in previous Inventories. EPA removed the pneumatic controller Gas STAR reductions from its calculations.

Oil Well Completions

The Inventory previously did not distinguish between oil well completions and workovers with hydraulic fracturing (HF) and oil well completions and workovers without hydraulic fracturing. The Inventory emission factors for all oil well completions and workovers were developed using an assumption that all oil well workovers and completions are flared. In the current Inventory, an estimate for the subcategories of oil well completions with hydraulic fracturing with and without controls was included. This estimate was developed using an uncontrolled emission factor developed as part of the analysis supporting the OOOOa NSPS proposal (7.5 tons CH₄/completion)⁷¹, and a controlled emission factor that assumes 95 percent control efficiency (0.4 tons CH₄/completion). For the OOOOa proposal analysis, EPA extracted gas production data from oil well records in DrillingInfo, and developed average daily gas production rates (over the first month of production) for wells that were determined to have been completed with hydraulic fracturing in 2012. The average value for these wells was 255.47 Mcf/day. This was then multiplied by a 3 day completion duration, and a methane content value of 47 percent to develop the uncontrolled factor. Total annual national HF oil well completion data were developed from DrillingInfo data (DrillingInfo 2015). The Inventory uses the NSPS OOOOa proposal information for the percentage of oil well completions that are controlled due to state regulations, 7 percent and applies that value beginning in 2008. It is assumed in the inventory estimate that prior to 2008, all oil well completions with HF are uncontrolled. The inventory continues to use one estimate for workover emissions for completions of all types (i.e. both hydraulically fractured and non-hydraulically fractured). This recalculation results in a 3 MMT CO₂ Eq. increase from the previous 2013 estimate for completions and workovers, and an average increase of 1 MMT CO₂ Eq. over the 1990 through 2013 time series.

Table 3-43: CH₄ Emissions from Oil Well Completions and Workovers (C&W) (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
HF Completions	0.6	0.9	1.7	3.0	3.0
NonHF Completions	+	+	+	+	+
Workovers (HF and nonHF)	+	+	+	+	+
Total C&W	0.6	0.9	1.7	3.0	3.0

⁷¹ The value presented in the NSPS proposal, 9.72 short tons was the average emissions calculated for the subset of HF oil well completions with GOR >300 scf/bbl. The inventory averaged emissions from the same base data set, without the GOR <300 scf/bbl exclusion, so that for the inventory, the emission factor can be applied to all HF oil well completions in the U.S., including those with lower GOR.

<i>Previous Total C&W</i>	+		+		+		+	<i>NA</i>
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+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Values in *italics* are from the previous Inventory.

Planned Improvements

In response to the public review draft and earlier released memorandum outlining potential revisions to the production segment, EPA received feedback from stakeholders that will be further considered to refine future Inventories.

In the production segment, some commenters suggested that the approach taken overestimates equipment counts in the production segment, while others suggested that the approach was appropriate. The EPA will further consider how activity factors developed from GHGRP data may over- or under-represent equipment counts for non-GHGRP facilities (those not meeting the emissions reporting threshold). Preliminary assessment by EPA of this issue by disaggregating GHGRP reporter data by number of wells reported indicated that reporters with fewer wells had higher equipment counts per well than average. EPA will continue to explore other methods to assess whether the non-GHGRP population may have different average equipment counts than the reporting population and how this may be reflected in the Inventory. EPA will continue to assess GHGRP data for additional updates to the inventory. While comments received supported the update to include hydraulically fractured oil well completions as a distinct subcategory category, commenters differed on the recommended data for the update (DI Desktop approach versus GHGRP data). EPA will review the first year of reported GHGRP data on hydraulically fractured oil well completions and workovers and will consider how it may be used to update the inventory. Additionally, EPA received comments suggesting that EPA use associated gas venting and flaring data from GHGRP and apply it to the population of associated gas wells in the Inventory, to address the concern that casinghead gas emissions occur at a wider set of associated gas wells, not only at stripper wells. EPA will investigate the appropriateness of using associated gas venting and flaring data from the GHGRP to replace or supplement current estimates of casinghead gas venting from stripper wells in the 2017 Inventory.

In response to the public review memoranda, EPA also received feedback from stakeholders on aspects of emission sources that were not significantly revised in the 2016 (current) Inventory. Stakeholders noted that data generated by Allen et al. in recent studies of pneumatic controller emissions in the production segment might be used to develop a separate emission factor for malfunctioning devices (in addition to the bleed type-specific factors developed from GHGRP data and used in the 2016 [current] Inventory). EPA will evaluate available data studies on this emission source.

EPA will continue to consider stakeholder feedback on the methodology used to develop counts of active oil wells across the time series.

EPA will continue to consider methods to refine the time series. For many sources with, the time series calculations rely on linear interpolation between 1990's data points and 2011 data points.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category, noted the currently data is limited, and suggested reviewing data that will become available in the future.

Uncertainty

As discussed in the Recalculations Discussion section above, EPA made several revisions to the methodology and data for the 2016 (current) Inventory. As noted in the Uncertainty section above, EPA has not yet updated its uncertainty analysis to reflect this new information. It is difficult to project whether the uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 24 percent and plus 149 percent) given these revisions.

To update its uncertainty analysis, EPA will conduct a formal quantitative uncertainty analysis similar to that conducted for the 2011 Inventory using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique) using new data and taking into account stakeholder input received. For more information, please see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty

Estimates” (EPA 2016a).⁷² As in the 2011 Inventory analysis, EPA will first identify a select number of top-emitting emission sources for each source category. Refer to “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” for more information on planned improvements regarding uncertainty (EPA 2016a).

Box 3-7: Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO₂ is produced from both naturally-occurring CO₂ reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the Inventory, emissions from naturally-produced CO₂ are estimated based on the specific application.

In the Inventory, CO₂ that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO₂ used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO₂ emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO₂ is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC includes methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO₂. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO₂ captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO₂ emissions estimates for geologic storage.

In the United States, facilities that produce CO₂ for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO₂, exporters of CO₂, facilities that conduct geologic sequestration of CO₂, and facilities that inject CO₂ underground (including facilities conducting EOR), are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities conducting geologic sequestration of CO₂ are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO₂ sequestered using a mass balance approach.

Available GHGRP data relevant for this inventory estimate consists of national-level annual quantities of CO₂ captured and extracted for EOR applications for 2010 to 2014. In the current Inventory, the previous estimates for 2010 to 2013 were replaced with GHGRP data for 2010 to 2013, and estimates for 2014 were directly taken from the reported GHGRP data for 2014. For the year 2013, this update has resulted in an increase of approximately 28 percent over the previous estimate. Using the GHGRP data has resulted in an average annual increase of approximately 11 MMT CO₂ Eq., or by approximately 25 percent, over the time series 2010 through 2013.

EPA will continue to evaluate the availability of additional GHGRP data and other opportunities for improving the emission estimates.

These estimates indicate that the amount of CO₂ captured and extracted from industrial and natural sites for EOR applications in 2014 is 59.3 MMT CO₂ Eq. (59,318 kt) (see Table 3-44 and Table 3-45). Site-specific monitoring and reporting data for CO₂ injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO₂ is emitted.

Table 3-44: Potential Emissions from CO₂ Capture and Extraction for EOR Operations (MMT CO₂ Eq.)

Stage	1990	2005	2010	2011	2012	2013	2014
Capture Facilities	4.8	6.5	9.9	9.9	9.3	12.2	13.1
Extraction Facilities	20.8	28.3	44.8	48.4	48.9	47.0	46.2
Total	25.6	34.7	54.7	58.2	58.1	59.2	59.3

⁷² See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

Table 3-45: Potential Emissions from CO₂ Capture and Extraction for EOR Operations (kt)

Stage	1990	2005	2010	2011	2012	2013	2014
Capture Facilities	4,832	6,475	9,900	9,877	9,267	12,205	13,093
Extraction Facilities	20,811	28,267	44,759	48,370	48,869	46,984	46,225
Total	25,643	34,742	54,659	58,247	58,136	59,189	59,318

3.7 Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 176.1 MMT CO₂ Eq. (7,045 kt) of CH₄ in 2014, a 15 percent decrease compared to 1990 emissions, and a slight (i.e., less than 1 percent) increase compared to 2013 emissions (see Table 3-46, Table 3-47, and Table 3-48) and 42.4 MMT CO₂ Eq. (42,351 kt) of non-combustion CO₂ in 2014, a 12 percent increase compared to 1990 emissions.

The 1990 to 2014 trend is not consistent across segments. Overall, the 1990 to 2014 decrease in CH₄ emissions is due primarily to the decrease in emissions from in the transmission/storage and distribution segments. Over the same time period, the production and processing segments saw increased methane emissions, of 31 and 13 percent, respectively. Natural gas systems also emitted 42.4 MMT CO₂ Eq. (42,351 kt) of non-combustion CO₂ in 2014, a 12 percent increase compared to 1990 emissions, and a 10 percent increase from 2013 emissions (see Table 3-49 and Table 3-50). Both the 1990 to 2014 and the 2013 to 2014 increases in CO₂ are due primarily to flaring; the volume of gas flared increased 93 percent from 1990 and 12 percent from 2013.

CH₄ and non-combustion CO₂ emissions from natural gas systems include those resulting from normal operations, routine maintenance, and system upsets. Emissions from normal operations include: natural gas engine and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic controllers, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH₄ and non-combustion CO₂ emissions are discussed.

Production (including gathering and boosting). In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, and well-site gas treatment facilities such as dehydrators and separators. Gathering and boosting emission sources are not reported under a unique segment, but are included within the production sector. The gathering and boosting segment of natural gas systems comprises gathering and boosting stations (with multiple emission sources on site) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer points are typically used to segregate sources between each segment). Emissions from production (including gathering and boosting) account for 62 percent of CH₄ emissions and 44 percent of non-combustion CO₂ emissions from natural gas systems in 2014. Emissions from gathering stations, pneumatic controllers, kimray pumps, liquids unloading, condensate tanks, gathering pipeline leaks, and offshore platforms account for the majority of CH₄ emissions in 2014. Flaring emissions account for the majority of the non-combustion CO₂ emissions. CH₄ emissions from production increased by 31 percent from 1990 to 2014, due primarily to increases in emissions from gathering and boosting stations (due to an increase in the number of stations), increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers), and condensate tanks (due to an increase in condensate produced). CO₂ emissions from production increased 88 percent from 1990 to 2014 due primarily to increases in flaring.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system. Fugitive CH₄ emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO₂ emissions come from acid gas removal (AGR) units, which are designed to remove CO₂ from natural gas.

Processing plants account for 14 percent of CH₄ emissions and 56 percent of non-combustion CO₂ emissions from natural gas systems. CH₄ emissions from processing increased by 13 percent from 1990 to 2014 as emissions from compressors increased along with the quantity of gas produced. CO₂ emissions from processing decreased by 15 percent from 1990 to 2014, as a result of a decrease in acid gas removal emissions.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the U.S. transmission system. Fugitive CH₄ emissions from these compressor stations, and venting from pneumatic controllers account for the majority of the emissions from this stage. Uncombusted engine exhaust and pipeline venting are also sources of CH₄ emissions from transmission. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from storage. CH₄ emissions from the transmission and storage sector account for approximately 18 percent of emissions from natural gas systems, while CO₂ emissions from transmission and storage account for less than 1 percent of the non-combustion CO₂ emissions from natural gas systems. CH₄ emissions from this source decreased by 45 percent from 1990 to 2014 due to reduced compressor station emissions (including emissions from compressors and fugitives). CO₂ emissions from transmission and storage have decreased by 37 percent from 1990 to 2014, also due to reduced compressor station emissions.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were 1,264,340 miles of distribution mains in 2014, an increase of over 320,000 miles since 1990 (PHMSA 2015). Distribution system emissions, which account for 6 percent of CH₄ emissions from natural gas systems and less than 1 percent of non-combustion CO₂ emissions, result mainly from fugitive emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH₄ and CO₂ emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH₄ emissions in 2014 were 74 percent lower than 1990 levels (changed from 43.5 MMT CO₂ Eq. to 11.1 MMT CO₂ Eq.), while distribution CO₂ emissions in 2014 were 72 percent lower than 1990 levels (CO₂ emission from this segment are less than 0.1 MMT CO₂ Eq. across the time series).

Total CH₄ emissions for the four major stages of natural gas systems are shown in MMT CO₂ Eq. (Table 3-46) and kt (Table 3-47). Table 3-48 provides additional information on how the estimates in Table 3-46 were calculated. Table 3-48 shows the calculated CH₄ release (i.e., potential emissions before any controls are applied) from each stage, and the amount of CH₄ that is estimated to have been flared, captured, or otherwise controlled, and therefore not emitted to the atmosphere. Subtracting the value for CH₄ that is controlled, from the value for calculated potential release of CH₄, results in the total emissions values. More disaggregated information on potential emissions and emissions is available in Annex 3.6. See Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems.

Table 3-46: CH₄ Emissions from Natural Gas Systems (MMT CO₂ Eq.)^a

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	83.4	108.1	108.3	108.8	111.1	110.7	109.0
Processing	21.3	16.4	17.9	21.3	22.3	22.6	24.0
Transmission and Storage	58.6	30.7	27.5	28.8	27.9	30.8	32.1
Distribution	43.5	22.1	12.5	11.2	11.4	11.5	11.1
Total	206.8	177.3	166.2	170.1	172.6	175.6	176.1

^a These values represent CH₄ emitted to the atmosphere. CH₄ that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

Note: Totals may not sum due to independent rounding.

Table 3-47: CH₄ Emissions from Natural Gas Systems (kt)^a

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	3,335	4,326	4,330	4,352	4,442	4,429	4,359
Processing	852	655	717	851	890	904	960
Transmission and Storage	2,343	1,230	1,100	1,152	1,116	1,232	1,282
Distribution	1,741	884	500	449	457	458	444
Total	8,270	7,093	6,647	6,803	6,906	7,023	7,045

^a These values represent CH₄ emitted to the atmosphere. CH₄ that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

Note: Totals may not sum due to independent rounding.

Table 3-48: Calculated Potential CH₄ and Captured/Combusted CH₄ from Natural Gas Systems (MMT CO₂ Eq.)

	1990	2005	2010	2011	2012	2013	2014
Calculated Potential^a	206.9	202.7	196.3	196.5	199.6	202.3	203.8
Field Production	83.5	115.7	120.5	121.3	123.6	124.2	123.3
Processing	21.3	20.6	23.6	25.2	26.2	26.5	27.9
Transmission and Storage	58.6	43.1	38.3	37.3	37.3	39.1	40.4
Distribution	43.5	23.3	13.9	12.7	12.5	12.5	12.1
Captured/Combusted^b	0.1	25.4	30.1	26.4	27.0	26.7	27.7
Field Production	0.1	7.6	12.2	12.5	12.5	13.5	14.4
Processing	+	4.2	5.7	3.9	3.9	3.9	4.0
Transmission and Storage	+	12.4	10.8	8.5	9.4	8.3	8.4
Distribution	+	1.2	1.4	1.5	1.1	1.0	1.0
Net Emissions	206.8	177.3	166.2	170.1	172.6	175.6	176.1
Field Production	83.4	108.1	108.3	108.8	111.1	110.7	109.0
Processing	21.3	16.4	17.9	21.3	22.3	22.6	24.0
Transmission and Storage	58.6	30.7	27.5	28.8	27.9	30.8	32.1
Distribution	43.5	22.1	12.5	11.2	11.4	11.5	11.1

+ Does not exceed 0.1 MMT CO₂ Eq.

^a In this context, “potential” means the total emissions calculated before voluntary reductions and regulatory controls are applied.

^b In 2014, over half of the capture and combustion accounted here is in the production segment, while 14 percent is from processing, 30 percent from transmission and storage, and 4 percent from distribution. For additional information, please see Annex 3.6.

Note: Totals may not sum due to independent rounding.

Table 3-49: Non-combustion CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq.)

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	9.9	8.3	11.0	14.1	13.7	16.6	18.6
Processing	27.8	21.7	21.3	21.5	21.5	21.8	23.7
Transmission and Storage	0.1	+	+	+	+	+	+
Distribution	0.1	+	+	+	+	+	+
Total	37.7	30.1	32.4	35.7	35.2	38.5	42.4

+ Does not exceed 0.1 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-50: Non-combustion CO₂ Emissions from Natural Gas Systems (kt)

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	9,857	8,260	11,041	14,146	13,684	16,649	18,585
Processing	27,763	21,746	21,346	21,466	21,469	21,756	23,713

Transmission and Storage	62	43	37	36	35	37	39
Distribution	50	27	16	15	14	14	14
Total	37,732	30,076	32,439	35,662	35,203	38,457	42,351

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for natural gas emissions estimates presented in this Inventory involves the calculation of CH₄ and CO₂ emissions for over 100 emissions sources, and then the summation of emissions for each natural gas segment.

The approach for calculating emissions for natural gas systems generally involves the application of emission factors to activity data. For some sources, the approach uses what are considered “potential methane factors,” and reduction data to calculate net emissions; for other sources, the approach uses technology-specific emission factors or emission factors that vary over time to take into account changes to technologies and practices, and these calculate net emissions directly.

The approach of calculating potential CH₄ and then applying reductions data to calculate net emissions was used to ensure a time series that reflects real emission trends. As noted below, key data on emissions from many sources are from 1996 GRI/EPA report containing data collected in 1992. Since the time of this study, practices and technologies have changed. While this study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would, in many cases, overestimate emissions. As updated emission factors reflecting changing practices are not available for some sources, the 1992 emission factors continue to be used for some sources for all years of the Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time. For the Inventory, the calculated potential emissions are adjusted using data on reductions reported to the Natural Gas STAR program, and data on regulations that result in CH₄ reductions. The revisions in the current inventory (see Recalculations Discussion below) result in net emission approaches being used for many sources in the inventory.

The calculation of emissions from natural gas systems is outlined below:

Step 1. Calculate Potential Methane (or Net Methane) – Collect activity data on production and equipment in use and apply emission factors (i.e., scf gas per unit or activity)

Step 2. Compile Reductions Data – Calculate the amount of the methane that is not emitted, using data on voluntary action and regulations

Step 3. Calculate Net Emissions – Deduct methane that is not emitted from the total methane potential estimates to develop net CH₄ emissions, and calculate CO₂ emissions

Step 1. Calculate Potential Methane (or Net Methane)—Collect activity data on production and equipment in use and apply emission factors

In the first step, potential CH₄ is calculated by multiplying activity data (such as miles of pipeline or number of wells) by factors that relate that activity data to potential CH₄. Potential CH₄ is the amount of CH₄ that would be emitted in the absence of any control technology or mitigation activity. It is important to note that potential CH₄ factors in most cases do not represent emitted CH₄, and must be adjusted for any emissions-reducing technologies, or practices, as appropriate. For more information, please see the Annex.

Potential Methane Factors and Net Emission Factors

A primary basis for estimates of CH₄ and non-combustion-related CO₂ emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute (GRI) and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH₄ emission factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The EPA/GRI study was based on a combination of process engineering studies, collection of activity data, and measurements at representative gas facilities conducted in the early 1990s. Methane compositions from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas

Composition Databases (GTI 2001) are adjusted year to year using gross production for oil and gas supply National Energy Modeling System (NEMS) regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the CH₄ composition for each NEMS oil and gas supply module region. The emission factors used to estimate CH₄ were also used to calculate non-combustion CO₂ emissions. Data from GTI 2001 were used to adapt the CH₄ emission factors into non-combustion related CO₂ emission factors. Additional information about CO₂ content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO₂ emission factors.

Although the Inventory primarily uses EPA/GRI emission factors (especially for early years of the time series), EPA has made revisions to the potential factor methodology in the emissions estimates for several sources in recent Inventories. For gas well completions and workovers (refracturing) with hydraulic fracturing, EPA uses its Greenhouse Gas Reporting Program (GHGRP) Subpart W data to stratify the emission sources into four different categories and developed CH₄ emission factors for each category. For liquids unloading, EPA calculates national emissions through the use of region-specific emission factors developed from well data collected in a survey conducted by API/ANGA (API/ANGA 2012). In the current Inventory, EPA has used data generated by studies and the GHGRP to develop emission factors that are control category-specific (e.g., bleed rate-specific emission factors for pneumatic controllers in the production and transmission and storage segments) and to reflect current practices for activities (e.g., distribution M&R station emission factors for recent years). For these sources, the emission factors are not potential factors, but are instead factors for net emissions.

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH₄ and non-combustion CO₂ emissions from natural gas systems.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc (DrillingInfo 2015); American Gas Association (AGA 1991 through 1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2015a, 2015b, 2015c); the Natural Gas STAR Program annual emissions savings (EPA 2013c); Oil and Gas Journal (OGJ 1997 through 2015); Pipeline and Hazardous Materials Safety Administration (PHMSA 2015a, 2015b); Federal Energy Regulatory Commission (FERC 2015); Greenhouse Gas Reporting Program (EPA 2015); other Energy Information Administration data and publications (EIA 2001, 2004, 2012, 2013, 2014); (EPA 1999); Conservation Commission (Wyoming 2015); and the Alabama State Oil and Gas Board (Alabama 2015).

For a few sources, recent direct activity data are not available. For these sources, either 2013 data was used as a proxy for 2014 data, or a set of industry activity data drivers was developed and used to calculate activity data over the time series. Drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations. More information on activity data and drivers is available in Annex 3.6.

Step 2. Compile Reductions Data—Calculate the amount of the CH₄ that is not emitted, using data on voluntary action and regulations

The emissions calculated in Step 1 above for many sources represent potential emissions from an activity, and do not take into account use of technologies and practices that reduce emissions. To take into account use of such technologies, data, where available, are collected on both regulatory and voluntary reductions. Regulatory actions taken into account using this method include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents and condensate tanks. Voluntary reductions included in the Inventory are those reported to Natural Gas STAR. For more information on these reductions, please see Annex 3.6. The emission estimates presented in Table 3-46 and Table 3-47 are the CH₄ that is emitted to the atmosphere (i.e., net emissions), not potential emissions without capture or flaring.

The Inventory also includes the impacts of the New Source Performance Standards (NSPS) Subpart OOOO, which came into effect in October 2012. By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific CH₄ emission factors for each category, EPA is implicitly accounting for Subpart OOOO reductions from hydraulically fractured gas wells. The method for calculating emissions from pneumatic controllers (by bleed rate category) also implicitly accounts for NSPS reductions in the high bleed pneumatic controller category.

The use of data from the EPA's GHGRP and recent studies to revise certain emission factors as discussed above obviated the need to apply Gas STAR or other reductions data for those sources (i.e., the calculated emissions were already net emissions, instead of potential emissions). More information is in the Recalculations Discussion below.

Step 3. Calculate Net Emissions—Deduct CH₄ that is not emitted from the total CH₄ potential estimates to develop net CH₄ emissions, and calculate CO₂ emissions

In the final step, emission reductions from voluntary and regulatory actions are deducted from the total calculated potential emissions to estimate the net emissions that are presented in Table 3-46, and included in the Inventory totals. As discussed above, for a number of categories (e.g., liquids unloading, condensate tanks, gas well completions and workovers with hydraulic fracturing, gathering stations, centrifugal compressors, pneumatic controllers, transmission and storage station fugitives, M&R stations, and pipeline leaks) emissions are calculated directly using emission factors that vary by technology or over time and account for any control measures in place that reduce CH₄ emissions.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the natural gas and petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory report that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies (e.g., Lamb, et al. 2015; Lyon, et al. 2015; Marchese, et al. 2015; Zimmerle, et al. 2015) and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is planning an update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information. At this time, it is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 19 percent and plus 30 percent) given the extensive nature of these revisions.

Details on EPA's planned uncertainty analysis are described in the Planned Improvements section.

EPA conducted a quantitative uncertainty analysis for the 2011 Inventory to determine the level of uncertainty surrounding estimates of emissions from natural gas systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emissions estimates using the 12 highest-emitting sources ("top 12 sources") for the year 2009. The @RISK analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted for the 2011 Inventory has not yet been updated for this inventory; instead, EPA has applied the uncertainty percentage ranges calculated previously for 2009 to the 2014 emissions estimates. As discussed in the Recalculations Discussion section, EPA has used findings from multiple recently published studies along with GHGRP Subpart W data to revise the emission factors and activity data for many emission sources. Given these substantive revisions, it is unlikely that the 2009 uncertainty ranges applied will reflect the uncertainty associated with the recently revised emission factors and activity data sources. Details on an updated uncertainty analysis to reflect recent recalculations are described in the Planned Improvements section.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2014, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-51. Natural gas systems CH₄ emissions in 2014 were estimated to be between 142.7 and 229.0 MMT CO₂ Eq. at a 95 percent confidence level, based on previously calculated uncertainty. Natural gas systems non-energy CO₂ emissions in 2014 were estimated to be between 34.3 and 55.1 MMT CO₂ Eq. at a 95 percent confidence level.

Table 3-51: Approach 2 Quantitative Uncertainty Estimates for CH₄ and Non-energy CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			(%)		Lower Bound ^b	Upper Bound ^b
			Lower Bound ^b	Upper Bound ^b		
Natural Gas Systems	CH ₄	176.1	142.7	229.0	-19%	+30%
Natural Gas Systems ^c	CO ₂	42.4	34.3	55.1	-19%	+30%

^a Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2009.

^b All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in Table 3-46 and Table 3-47.

^c An uncertainty analysis for the non-energy CO₂ emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH₄ uncertainty analysis was applied to the point estimate of non-energy CO₂ emissions

EPA compared the quantitative uncertainty estimates for CH₄ emissions in recent years from natural gas systems to those reported in recently published studies (see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” [EPA 2016a]).⁷³ All studies reviewed for uncertainty information used the Monte Carlo simulation technique to examine uncertainty bounds for the estimates reported which is in line with the IPCC recommended Approach 2 methodology. The uncertainty ranges in the reported studies differ from those of EPA. However, it is difficult to extrapolate uncertainty ranges from these studies to apply to the Inventory estimates because the Inventory source category level uncertainty analysis is not directly comparable to source- or segment-specific uncertainty analyses in these studies. Further, the methodologies and data sources used in estimating CH₄ emissions in these studies differ significantly from the studies underlying previous Inventory methodologies.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The natural gas emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through annual expert and public review periods. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made several updates, including revisions to production segment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility emissions, transmission and storage station activity and emissions data, distribution segment emissions data for pipelines, distribution segment M&R station activity and emissions data, and distribution segment customer meter emissions data.

⁷³ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

From December 2015 through February 2016, the EPA released four draft memoranda that discussed the changes under consideration and requested stakeholder feedback on those changes. See “Revisions under Consideration for Natural Gas and Petroleum Production Emissions,” “Revisions under Consideration for Gathering and Boosting Emissions,” “Revisions under Consideration for Transmission and Storage Emissions,” and “Revisions under Consideration for Distribution Emissions,” available at <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

The impact of all revisions to natural gas systems is an increase of 18 MMT CO₂ Eq., or 12 percent, comparing the 2013 value from last year’s Inventory to the current Inventory. Over the time series, the average change is an increase of 13 MMT CO₂ Eq., or 7 percent.

Recalculations for the production segment (including gathering and boosting facilities) resulted in a large increase in the 2013 CH₄ emission estimate, from 47.0 MMT CO₂ Eq. in the previous (2015) Inventory, to 110.7 MMT CO₂ Eq. in the current (2016) Inventory, or 136 percent. Over the time series, the average change is an increase of 35 MMT CO₂ Eq., or 57 percent.

Although there were no methodological updates to the processing segment, recalculations due to updated data (specifically data on national dry gas production in 2013, which were revised slightly downwards) impacted emissions estimates, resulting in a decrease of 0.1 MMT CO₂ Eq., or less than 1 percent comparing the 2013 value from last year’s Inventory to the current Inventory. Over the time series, the average change was less than 1 percent.

Recalculations for the transmission and storage segment resulted in a large decrease in the 2013 CH₄ emission estimate, from 54.4 MMT CO₂ Eq. in the previous (2015) Inventory, to 30.8 MMT CO₂ Eq. in the current (2016) Inventory, or 43 percent. Over the time series, the average change is a decrease of 13 MMT CO₂ Eq., or 25 percent.

Recalculations for the distribution segment also resulted in a large decrease in the 2013 CH₄ emission estimate, from 33.3 MMT CO₂ Eq. in the previous (2015) Inventory, to 11.5 MMT CO₂ Eq. in the current (2016) Inventory, or 65 percent. Over the time series, the average change is a decrease of 9 MMT CO₂ Eq., or 27 percent.

Production

This section references the final 2016 (current) Inventory production segment supporting memoranda: “Revisions to Natural Gas and Petroleum Production Emissions” and “Revisions to Natural Gas Gathering and Boosting Emissions” (EPA 2016b and EPA 2016c).⁷⁴ These memoranda contain further details and documentation of recalculations.

Using newly available GHGRP activity data, the EPA developed activity factors (i.e., counts per gas well) for in-line heaters, separators, dehydrators, compressors, meters/piping, pneumatic pumps, and pneumatic controllers. EPA reviewed this new data source and the previous data, assessed stakeholder feedback, and determined that the previous data source represents activities from the time period in which the data were collected (early 1990s) and the new GHGRP data source represents activities from recent years. The EPA applied the updated activity factors to calculate emissions from these sources for the years from 2011 to 2014 in the 2016 (current) Inventory natural gas production segment, while retaining the previous activity factors for 1990 to 1992. For years 1993 through 2010, the EPA calculated equipment counts by linearly interpolating between the data points of per well equipment counts in 1992 (based on GRI/EPA) and per well equipment counts in 2011 (based on GHGRP). This reflects an assumed gradual transition from the counts per well observed in the 1996 study and the counts observed in the recent GHGRP data.

The production segment activity data revisions not only reflect more current information on activity, but also tailor these emission sources to specifically reflect activity occurring at well pad facilities and not at gathering/centralized facilities. As discussed below and in the two supporting memoranda for the production segment, EPA has also implemented revisions to the gathering and boosting sub-segment so that equipment leaks from both types of facilities are fully, but separately, represented. In the public review draft, EPA noted potential issues with ensuring that vented emissions from certain equipment (e.g., pneumatic controllers, chemical injection pumps, dehydrator vents, and Kimray pumps) are not double-counted or inadvertently excluded due to these methodological revisions.

⁷⁴ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

The 2016 (current) Inventory methodology for these sources generally addresses this concern. Please refer to “Revisions to Natural Gas and Petroleum Production Emissions” for more information (EPA 2015b).

The impact of using activity factors developed from GHGRP data is an increase in emissions. This increase is shown in Table 3-52. For the year 2013, compared to the previous Inventory, the calculated CH₄ emissions increase due to use of revised activity factors for heaters, separators, dehydrators, compressors, and meters/piping is approximately 0.4 MMT CO₂ Eq. In addition, as dehydrator counts are an input to the calculation of emissions from the dehydrator vent and Kimray pump source, the revision to activity data impacted those estimates as well, resulting in a decrease of 2 MMT CO₂ Eq. for dehydrator vents, and 7 MMT CO₂ Eq. for Kimray pumps (comparing updated 2013 estimate to previous 2013 estimate). For chemical injection pumps, in addition to updating the activity data, emission factors were also recalculated using GHGRP data. This recalculation resulted in an increase in calculated emissions from chemical pumps for 2013 of 1.7 MMT CO₂ Eq., compared with the previous inventory estimate for 2013.

Table 3-52: CH₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO₂ Eq.)

Type	Source	1990	2005	2010	2013	2014
Venting	Chemical Injection Pumps	0.7	2.4	3.3	3.2	3.2
	<i>Previous-Chemical Injection Pumps</i>	<i>0.7</i>	<i>1.4</i>	<i>1.6</i>	<i>1.5</i>	<i>NA</i>
Fugitive	Dehydrators	0.4	0.3	0.2	0.2	0.2
	<i>Previous-Dehydrators</i>	<i>0.4</i>	<i>0.7</i>	<i>0.8</i>	<i>0.8</i>	<i>NA</i>
Fugitive	Separators	1.1	2.4	3.0	3.0	3.0
	<i>Previous-Separators</i>	<i>1.1</i>	<i>2.1</i>	<i>2.6</i>	<i>2.6</i>	<i>NA</i>
Fugitive	Heaters	0.3	0.5	0.6	0.6	0.6
	<i>Previous- Heaters</i>	<i>0.3</i>	<i>0.7</i>	<i>0.8</i>	<i>0.8</i>	<i>NA</i>
Fugitive	Meters/Piping	1.2	2.3	2.7	2.7	2.7
	<i>Previous-Meters/Piping</i>	<i>1.3</i>	<i>2.2</i>	<i>2.7</i>	<i>2.6</i>	<i>NA</i>
Fugitive	Compressors	0.8	1.9	2.4	2.4	2.4
	<i>Previous-Compressors</i>	<i>0.9</i>	<i>1.5</i>	<i>1.8</i>	<i>1.7</i>	<i>NA</i>

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

Using the GHGRP data, the EPA also developed technology-specific activity data and emission factors for pneumatic controllers. Reported data under the GHGRP allow for the development of pneumatic controller emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and the associated break-out of activity data into these categories. These revised emission factors and bleed type-specific activity data reflect net emissions. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data on pneumatic controller emissions is an increase of approximately 18.0 MMT CO₂ Eq., as shown in Table 3-53.

Table 3-53: CH₄ Emissions from Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	13.9	27.0	31.2	31.5	27.6
High bleed	+	12.1	10.9	4.8	3.3
Low bleed	8.4	0.6	1.1	0.6	1.0
Intermittent bleed	5.5	14.3	19.2	26.0	23.3
Previous-All	13.4	20.2	16.2	13.5	NA

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The 2015 Marchese et al. study assessed CH₄ emissions from an expanded universe of gathering stations compared with what was previously included in the Inventory. The Marchese et al. study analyzed emissions from five different types of gathering stations: compression only; compression and dehydration; compression, dehydration, and acid gas removal; dehydration only; and dehydration and acid gas removal. Previous Inventories estimated emissions from only gathering compression stations. In this Inventory, the EPA has applied a station-level emission factor and national activity estimates developed from the Marchese et al. data. See “Revisions to Natural Gas

Gathering and Boosting Emissions” for more information (EPA 2016c).⁷⁵ The impact of using revised activity data and emission factors for gathering stations cannot be straightforwardly determined based on the structure of previous Inventories (e.g., dehydrator emissions in previous inventories are not differentiated between well pad and gathering facility locations); however, due to the activity data revision alone, production segment emissions greatly increase compared to previous estimates. The station-level emission factor was applied to all years of the time series, and current activity data estimates were replaced with station counts based on the Marchese et al. estimate (scaled for earlier years based on national natural gas marketed production). Methane emissions from gathering and boosting are shown in Table 3-54.

Table 3-54: CH₄ Emissions from Gathering and Boosting (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Gathering and Boosting Stations	23.9	27.7	35.8	43.3	46.6

The EPA’s approach for revising the Inventory methodology to incorporate GHGRP data and Marchese et al. data obviates the need to apply Gas STAR reductions data for certain sources in the production segment. EPA carried forward reported reductions for sources that are not being revised to use a net emission factor approach. There are also significant Gas STAR reductions in the production segment that are not classified as applicable to specific emission sources (“other voluntary reductions” are 18 MMT CO₂ Eq. of CH₄ in year 2014). To address potential double-counting of reductions, a scaling factor was applied to the “other voluntary reductions” to reduce this reported amount based on an estimate of the fraction of those reductions that occur in the sources that are now calculated using net emissions approaches. This fraction was developed by dividing the net emissions from sources with net emissions approaches, by the total production segment emissions (without deducting the Gas STAR reductions). The result for 2014, is that approximately 50 percent of the reductions were estimated to occur in sources for which net emissions are now calculated, which yields an adjusted “other voluntary reduction” number of 9 MMT CO₂ Eq.

Transmission and Storage

This section references the final 2016 (current) Inventory Transmission and Storage supporting memorandum: “Revisions to Natural Gas Transmission and Storage Emissions” (EPA 2016d).⁷⁶ This memorandum contains further details and documentation of recalculations.

For transmission and storage non-compressor fugitive emissions in the 2016 (current) Inventory, EPA used Zimmerle et al. data to develop the activity data for transmission stations (“Alternative” approach) and EIA data on active storage fields, along with the Zimmerle estimate of storage stations per storage field to develop storage station counts. The EPA then applied emission factors from Zimmerle et al. to calculate emissions for fugitives from these sources.

Interpolation was used to create time series consistency between earlier years’ emission factors (1990-1992) that generally rely on data from GRI/EPA 1996 and the Zimmerle et al. emission factors for recent years. However, the station fugitive emission factors in previous Inventories included station fugitives but not compressor fugitives, and separate emission factors were applied for compressor emissions (including compressor fugitive and vented sources). Because Zimmerle et al. grouped compressor fugitives with station fugitives, the two sets of emission factors (GRI/EPA and Zimmerle et al.) cannot be directly compared. Therefore in the 2016 (current) Inventory, the EPA calculated total station-level emission factors for transmission and storage stations that include station and compressor fugitive sources as well as compressor vented sources.

In the 2016 (current) Inventory, the EPA incorporated Zimmerle et al. national population estimates of reciprocating and centrifugal compressor activity data, along with the GHGRP break out between centrifugal compressor seal types (wet versus dry seals), and Zimmerle et al. emission factor data, in development of emission estimates for compressors in transmission and storage.

⁷⁵ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

⁷⁶ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

In order to create time series consistency between earlier years' compressor count estimates (1990 to 1992) and the most recent years' compressor count estimates (2012 to 2014) that were calculated from Zimmerle et al. and GHGRP data, compressor counts for the years 1993 through 2011 were calculated using linear interpolation between the data endpoints of 1992 and 2012.

The overall impact of using revised emissions data and activity data from Zimmerle et al. and GHGRP is a decrease in emissions for station fugitives and compressors. For the year 2013, the CH₄ emissions decrease due to use of revised emission factors and activity data for transmission and storage station fugitives and compressor venting is approximately 18.4 MMT CO₂ Eq. Methane emissions from transmission stations are shown in Table 3-55, while methane emissions from storage stations are shown in Table 3-56.

Table 3-55: CH₄ Emissions from Transmission Stations (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Station Total Emissions	27.5	16.7	13.0	13.4	14.3
Station + Compressor					
Fugitive Emissions	NA	NA	NA	2.7	2.9
Reciprocating Compressor	NA	NA	NA	7.9	8.5
Centrifugal Compressor (wet seals)	NA	NA	NA	1.4	1.5
Centrifugal Compressor (dry seals)	NA	NA	NA	1.3	1.4
<i>Previous-Station Total</i>	<i>27.5</i>	<i>28.1</i>	<i>28.5</i>	<i>28.3</i>	<i>NA</i>
<i>Previous-Station Fugitives^a</i>	<i>2.7</i>	<i>2.8</i>	<i>2.8</i>	<i>2.8</i>	<i>NA</i>
<i>Previous-Reciprocating Compressor^a</i>	<i>18.6</i>	<i>19.2</i>	<i>19.4</i>	<i>19.3</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (wet seals)^a</i>	<i>6.2</i>	<i>5.9</i>	<i>5.9</i>	<i>5.8</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (dry seals)^a</i>	<i>+</i>	<i>0.3</i>	<i>0.4</i>	<i>0.4</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

*These values from the previous inventory cannot be compared to the estimates in this Inventory as the source categories have different definitions in their respective data sources (e.g., one includes certain fugitives, one does not).

Note: Values in *italics* are from the previous Inventory.

Table 3-56: CH₄ Emissions from Storage Stations (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Station Total Emissions	6.1	4.1	3.5	3.3	3.3
Station + Compressor					
Fugitive Emissions	NA	NA	NA	0.6	0.6
Reciprocating Compressor	NA	NA	NA	2.7	2.7
Centrifugal Compressor (wet seals)	NA	NA	NA	NA	NA
Centrifugal Compressor (dry seals)	NA	NA	NA	NA	NA
<i>Previous-Station Total</i>	<i>6.1</i>	<i>6.7</i>	<i>6.6</i>	<i>6.8</i>	<i>NA</i>
<i>Previous-Station Fugitives^a</i>	<i>1.4</i>	<i>1.5</i>	<i>1.5</i>	<i>1.5</i>	<i>NA</i>
<i>Previous-Reciprocating Compressor^a</i>	<i>3.9</i>	<i>4.3</i>	<i>4.3</i>	<i>4.4</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (wet seals)^a</i>	<i>0.8</i>	<i>0.8</i>	<i>0.7</i>	<i>0.6</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (dry seals)^a</i>	<i>+</i>	<i>0.1</i>	<i>0.2</i>	<i>0.3</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

* These values from the previous inventory cannot be compared to the estimates in this Inventory as the source categories have different definitions in their respective data sources (e.g., one includes certain fugitives, one does not).

Note: Values in *italics* are from the previous Inventory.

In the 2016 (current) Inventory, the transmission and storage pneumatic controller emissions have been calculated using the GHGRP data on controllers per station and emission factors. The overall impact of using revised emissions data and activity data from GHGRP was a decrease in emissions from transmission station pneumatic controllers and a slight decrease in emissions from storage station pneumatic controllers for recent time series years. For the year 2013, the CH₄ emissions decrease due to use of revised emission factors and activity data for transmission and storage station pneumatic controllers is 5.0 MMT CO₂ Eq. Methane emissions from transmission segment pneumatic controllers are shown in Table 3-57, while methane emissions from storage segment pneumatic controllers are shown in Table 3-58.

In order to create time series consistency between earlier years' pneumatic controller data (1990 to 1992) and the most recent years' data (2011 to 2014) when populating intermediate years, the EPA retained counts and estimates of weighted average emissions per controller in early years, then linearly interpolated the total count and weighted average emissions per controller in year 2011.

Table 3-57: CH₄ Emissions from Transmission Segment Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	5.3	1.8	0.9	0.7	0.7
High bleed	NA	NA	NA	0.3	0.3
Low bleed	NA	NA	NA	0.3	0.4
Intermittent bleed	NA	NA	NA	+	+
<i>Previous-All</i>	<i>5.3</i>	<i>5.2</i>	<i>5.3</i>	<i>5.2</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

Table 3-58: CH₄ Emissions from Storage Segment Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	1.1	0.9	0.7	0.8	0.7
High bleed	NA	NA	NA	0.6	0.6
Low bleed	NA	NA	NA	0.1	0.1
Intermittent bleed	NA	NA	NA	+	+
<i>Previous-All</i>	<i>1.1</i>	<i>1.2</i>	<i>1.2</i>	<i>1.3</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA's approach for revising the inventory methodology to incorporate Zimmerle et al. and GHGRP data in the transmission and storage segment resulted in net emissions being directly calculated for revised sources in each time series year. This obviated the need to apply Gas STAR reductions data for these sources. Previous Inventories have applied Gas STAR reductions to other specific transmission and storage segment sources including compressor engine and pipeline venting. EPA carried forward reported reductions for these sources since they are not being revised to use a net emission factor approach. There are also Gas STAR reductions in the transmission and storage segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 3.6 MMT CO₂ Eq. CH₄ in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA has revised the methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions," without adjustment, in the 2016 (current) Inventory.

Distribution

This section references the final 2016 (current) Inventory Distribution supporting memorandum: “Revisions to Natural Gas Distribution Emissions” (EPA 2016e).⁷⁷ This memorandum contains further details and documentation of recalculations.

For metering and regulating (M&R) stations, for the years from 2011 to 2014, in the 2016 (current) Inventory, the EPA used GHGRP reported activity data for counts of above ground and below ground stations. The EPA scaled the GHGRP station counts to the national level based on the miles of distribution pipeline main reported by GHGRP reporters, compared to the PHMSA national total miles of distribution pipeline main. The EPA then applied the existing inventory (from GRI) break out of station inlet pressure categories to the scaled counts of above ground and below ground M&R stations, and the station-level emission factors from Lamb et al. For years from 1990 to 2010, EPA used the previous inventory activity data for station counts. EPA used linear interpolation between GRI/EPA emission factors in early years (1990 to 1992) and Lamb et al. emission factors in recent years (2011 to 2014) for M&R stations.

For the year 2013, the M&R stations CH₄ emissions decrease due to use of revised emission factors and activity data is approximately 13.6 MMT CO₂ Eq. Methane emissions from M&R stations are shown in Table 3-59.

Table 3-59: CH₄ Emissions from M&R Stations (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
M&R	10.5	4.9	1.1	0.9	0.7
<i>Previous--M&R</i>	8.2	9.1	9.0	9.3	NA
R-Vault	+	0.1	0.1	+	+
<i>Previous--R-Vault</i>	+	+	+	+	NA
Reg	6.3	2.8	0.6	0.4	0.3
<i>Previous--Reg</i>	4.9	5.4	5.4	5.6	NA

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

For pipeline leaks, in the 2016 (current) Inventory, the EPA used the previous activity data sources for miles of pipeline by material (PHMSA) and for leaks per mile (GRI), and Lamb et al., data on emissions per leak for recent years of the time series. For the year 2013, the pipeline leaks CH₄ emissions decrease due to use of revised emission factors is approximately 9.2 MMT CO₂ Eq. Methane emissions from pipeline leaks are shown in Table 3-60.

EPA used linear interpolation between GRI/EPA emission factors in early years (1990 to 1992) and Lamb et al. emission factors in recent years (2011 to 2014) for pipeline leaks.

Table 3-60: CH₄ Emissions from Pipeline Leaks (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Mains	14.7	6.7	4.5	3.9	3.8
<i>Previous--Mains</i>	14.7	11.8	11.3	10.7	NA
Services	8.2	4.0	2.6	2.2	2.1
<i>Previous--Services</i>	8.2	6.2	5.1	4.6	NA

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

In the 2016 (current) Inventory, the EPA revised the emission factors for residential customer meters and commercial/ industrial customer meters. The EPA recalculated the residential customer meter emission factor by combining data from the 1996 GRI/EPA study (basis for previous Inventory emission factor) with more recent data from a GTI 2009 study and Clearstone 2011 study. The EPA weighted emission factors developed in each study by the number of meters surveyed in each study to develop the revised emission factor. In the 2016 (current) Inventory, the EPA applied the GTI 2009 commercial customer meter emission factor to the total count of commercial and

⁷⁷ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

industrial meters in the GHG Inventory. In addition, the EPA used an updated data source, identified by commenters on the public review Distribution memorandum for national customer meter counts (EIA data); previously, national customer meter counts were scaled from a 1992 base year value, but are now available directly for every year of the time series from EIA. For the year 2013, the customer meters CH₄ emissions increase due to use of revised emission factors and activity data is approximately 0.3 MMT CO₂ Eq. Methane emissions from customer meters are shown in Table 3-61.

For pipeline blowdowns and mishaps/dig-ins, the previous Inventories used base year 1992 distribution main and service miles and scaled the value for non-1992 years using relative residential gas consumption. However, scaling mileage based on residential gas consumption introduced volatility across the time series that does not likely correlate to pipeline mileage trends (as gas consumption is affected by other factors such as equipment efficiency and climate). In the 2016 (current) Inventory, the EPA used PHMSA data directly for the activity data in each time series year. The overall impact of using the revised activity data for pipeline blowdowns and mishaps/dig-ins is an increase in emissions. For the year 2013, the pipeline blowdowns CH₄ emissions increase due to use of revised activity data is approximately 0.04 MMT CO₂ Eq.; and for mishaps/dig-ins is approximately 0.6 MMT CO₂ Eq. Methane emissions from pipeline blowdown and mishaps/dig-ins are shown in Table 3-61.

Table 3-61: CH₄ Emissions for Other Distribution Sources (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Residential Meters	1.5	1.9	1.9	2.0	2.0
<i>Previous--Residential Meters</i>	2.6	2.8	2.8	2.9	NA
Commercial/Industry Meters	1.1	1.3	1.3	1.4	1.4
<i>Previous--Commercial/Industry Meters</i>	0.1	0.1	0.1	0.1	NA
Pressure Relief Valve Releases	+	+	+	+	+
<i>Previous--Pressure Relief Valve Releases</i>	+	+	+	+	NA
Pipeline Blowdowns	0.1	0.1	0.1	0.1	0.1
<i>Previous--Pipeline Blowdown</i>	0.1	0.1	0.1	0.1	NA
Mishaps (Dig-ins)	1.2	1.5	1.6	1.6	1.7
<i>Previous--Mishaps (Dig-ins)</i>	0.9	1.0	1.0	1.0	NA

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA's approach for revising the Inventory methodology to incorporate Lamb et al. and subpart W data in the distribution segment resulted in net emissions being directly calculated for M&R stations, pipeline leaks, and customer meters in each time series year. This obviates the need to apply Gas STAR reductions data for these sources. Previous Inventories have also applied Gas STAR reductions to mishaps/dig-ins. EPA carried forward reported reductions for this source since it is not being revised to use a net emission factor approach. There are also Gas STAR reductions in the distribution segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 1.0 MMT CO₂ Eq. CH₄ in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA has revised methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions" unadjusted in the 2016 (current) Inventory.

Planned Improvements

Production Segment Estimates

In response to the public review draft and earlier released memorandum outlining potential revisions to the production and gathering and boosting segment, EPA received feedback from stakeholders that will be further considered to refine future Inventories.

In the production segment, some commenters suggested that the approach taken overestimates equipment counts in the production segment, while others suggested that the approach was appropriate. The EPA will further consider

how activity factors developed from GHGRP data may over- or under-represent equipment counts for non-GHGRP facilities (those not meeting the emissions reporting threshold). Preliminary assessment by EPA of this issue by disaggregating GHGRP reporter data by number of wells reported indicated that reporters with fewer wells had higher equipment counts per well than average. EPA will continue to explore other methods to assess whether the non-GHGRP population may have different average equipment counts than the reporting population and how this may be reflected in the Inventory. The EPA will also consider calculation of activity factors from GHGRP data (equipment and pneumatic controller counts per well) on a more granular basis, such as by geologic basin. EPA will continue to consider stakeholder feedback on the methodology used to develop counts of active wells (non-associated gas wells and gas wells with hydraulic fracturing) across the time series.

In response to the public review memoranda, EPA also received feedback from stakeholders on aspects of emission sources that were not significantly revised in the 2016 (current) Inventory. Stakeholders noted that data generated by Allen et al. in recent studies of pneumatic controller emissions in the production segment might be used to develop a separate emission factor for malfunctioning devices (in addition to the bleed type-specific factors developed from GHGRP data and used in the 2016 (current) Inventory). Stakeholders also recommended further investigating the emissions estimation methodology for gathering pipeline emissions, as the current factor is based on leak measurements from distribution mains conducted in the early 1990s. EPA will evaluate available data studies on this emission sources, and also take into account material-specific gathering pipeline activity data that will be available through the GHGRP.

EPA is considering updates to its estimates for liquids unloading. Data from a 2012 report published by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) were used to develop regional activity data and regional emission factors for gas well liquids unloading activities for Natural Gas Systems. EPA is considering how data from GHGRP and/or Allen et al. (2014a) can be used to update the Inventory estimates for this source.⁷⁸ Some commenters supported the use of scaled-up GHGRP data to calculate emissions from this source. Using the general scale up approach used for other production sources gives an approximation of a national estimate of 10 MMT CO₂ Eq. for 2013 (4.6 MMT CO₂ Eq. was reported from liquids unloading in 2013, from a total reported 208,991 wellheads estimated to be in the natural gas segment. The Inventory national well count total for 2013 is 454,491), compared with 6.5 MMT CO₂ Eq. in the current inventory.

EPA received mixed feedback on the update for gathering stations, with some commenters supporting the use of the Marchese et al. data, and others not supporting the update and recommending waiting for GHGRP data to update emissions from this source. Additionally, commenters recommended that EPA separate out emissions from gathering and boosting facilities from those from field production sites and noted that upcoming studies and GHGRP data may inform emissions estimates from this source. In the 2016 (current) Inventory, the EPA has presented gathering facility and gathering pipeline emissions as a "Gathering and Boosting" subsegment within the production segment; EPA will continue to consider how these sources may be presented in future Inventories. To address potential double counting, condensate storage tanks might be disaggregated between well pad facilities and gathering facilities in future Inventories. Stakeholder feedback included suggestions on how data from the Marchese et al. study and GHGRP data might be used, which EPA will consider for next year's inventory. One commenter suggested that the potential overlap count be estimated to be 3.4 percent of the emissions from condensate tanks.

Processing Estimates

Commenters recommended consideration of recent data sources (Marchese et al. 2015 and GHGRP) for revisions to gas processing segment estimates. Commenters had mixed feedback on these data sources with some commenters supporting use of Marchese et al. and other supporting use of GHGRP data.

⁷⁸ Please see the memorandum "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Potential Revisions to Liquids Unloading Estimates" (EPA 2015e) available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>

Transmission and Storage Estimates

In response to the public review memorandum outlining potential revisions to the transmission and storage segment, EPA received feedback from stakeholders that will be further considered to refine implementation of the 2016 revisions in future Inventories and to implement additional revisions. The EPA will consider approaches to developing average emission factors that integrate data from both recent studies and subpart W data. The EPA will seek more data to support or replace the Zimmerle et al. study assumption of 0.89 storage stations per field. The EPA will take into account findings emerging from ongoing research efforts by groups such as API (to better characterize emissions from pneumatic controllers) and Pipeline Research Council International (to analyze subpart W data). The EPA will also investigate potential revisions to certain emission sources not addressed in recent revisions but highlighted by commenters, including reciprocating compressor engines and storage tank dump valves.

In fall of 2015, a well in a California storage field began leaking methane at an estimated rate of 50 tons of CH₄ per day. The well was permanently sealed in February of 2016. EPA plans to include 2015 emissions from this source in next year's inventory (2017 report covering 1990 to 2015 emissions). EPA will review and potentially incorporate estimates of emissions from the leak, such as estimates developed by the California Air Resources Board (CARB). For information on CARB estimates, see http://www.arb.ca.gov/research/aliso_canyon_natural_gas_leak.htm.

Distribution Estimates

In response to the public review memorandum outlining potential revisions to the distribution segment, EPA received feedback from stakeholders that will be further considered to refine implementation of the 2016 revisions in future Inventories and to implement additional revisions. The EPA will assess differences between the Lamb et al. study and characteristics of the GHGRP population. The EPA will consider current interpolation approaches to use GRI factors later into the time series (e.g., if information is received indicating a specific time frame for the transition to lower-emitting equipment and practices). The EPA will assess whether available data support methodological revisions to differentiate new versus vintage plastic pipelines in the Inventory. The EPA will assess any new data on commercial or industrial meters to potentially improve the current emission factor. While most commenters supported updates to this segment, several commenters did not, referring to top down (e.g., tall tower) studies indicating the emissions may be higher than previously estimated, not lower. The EPA will continue to assess new top down and bottom up data in this segment.

Upcoming new data

GHGRP

Beginning in March 2016, GHGRP reporters will report data for gathering facilities over the GHGRP reporting threshold. The EPA will consider use of this data to update its estimates in the Inventory.

Commenters on recent Inventory drafts have recommended that EPA analyze and screen GHGRP data and exclude or correct outliers. Commenters have also recommended use of only measured GHGRP data in some cases. The EPA plans to continue reviewing data reported to its GHGRP for potential updates to data and methodology across all segments of natural gas systems.

Methane Challenge

In March 2016, EPA launched the Methane Challenge Program, through which oil and gas companies can make and track ambitious commitments to reduce methane emissions. EPA will assess new data received by the Methane Challenge Program on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions.

Other Updates

EPA is evaluating several other sources for potential updates to future Inventories.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category, noted the currently data is limited, and suggested reviewing data that will become available in the future.

The EPA continues to seek stakeholder feedback on natural gas systems super-emitter sources. The EPA will continue reviewing studies that could support potential revisions to inventory estimates, such as information from the Barnett Shale Campaign (e.g., Zavala et al. 2015). Several commenters noted superemitters detected and modeled in the Zimmerle et al. study but not incorporated into the inventory revision. In Zimmerle et al., superemitters were estimated to contribute 2.5 MMT CO₂ Eq. emissions to the study total estimate of emissions transmission and storage sources. The EPA will consider how unassigned superemitter emissions could be incorporated into the Inventory. EPA received mixed feedback on this issue with some commenters urging EPA to incorporate an estimate for superemitters, and others stating that inclusion of an estimate of unassigned superemitter emissions would be inappropriate and could result in double counting.

Uncertainty

As discussed in the Recalculations Discussion section above, EPA made several revisions in the 2016 (current) Inventory using information provided in recently published studies and the GHGRP Subpart W data, primarily including revisions to: production segment major equipment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility activity and emissions data, transmission and storage station activity and emissions data, distribution pipelines emissions data, distribution M&R station activity and emissions data, and distribution customer meter emissions data. As noted in the Uncertainty section above, EPA has not yet updated its uncertainty analysis to reflect this new information. At the present time, it is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 19 percent and plus 30 percent) given the extensive nature of these revisions.

To update its uncertainty analysis, EPA will conduct a formal quantitative uncertainty analysis similar to that conducted for the 2011 Inventory using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique) using new data and taking into account stakeholder input received. For more information, please see the Uncertainty Memorandum (EPA 2016a). As in the 2011 Inventory analysis, EPA will first identify a select number of top-emitting emission sources for each source category. Note that to compile the top-emitting list of emission sources for natural gas systems, individual emission sources were analyzed at the NEMS region level for the production segment (because certain emission factors vary by region for many production sources), and at the national level for other segments. EPA is considering removing the NEMS region disaggregation in future Inventories, and potentially replacing it with a different level of disaggregation, such as at the sub-basin level. Refer to “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty (EPA 2016a) for more information on planned improvements regarding uncertainty.”⁷⁹

3.8 Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2014 are reported in Table 3-62.

Table 3-62: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
NO _x	21,106	16,602	12,004	11,796	11,051	10,557	9,995

⁷⁹ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

Mobile Combustion	10,862	10,295	7,290	7,294	6,788	6,283	5,777
Stationary Combustion	10,023	5,858	4,092	3,807	3,567	3,579	3,522
Oil and Gas Activities	139	321	545	622	622	622	622
Waste Combustion	82	128	77	73	73	73	73
<i>International Bunker Fuels^a</i>	<i>1,956</i>	<i>1,704</i>	<i>1,790</i>	<i>1,553</i>	<i>1,398</i>	<i>1,139</i>	<i>1,138</i>
CO	125,640	64,985	45,148	44,088	42,273	40,459	38,643
Mobile Combustion	119,360	58,615	39,475	38,305	36,491	34,676	32,861
Stationary Combustion	5,000	4,648	4,103	4,170	4,170	4,170	4,169
Waste Combustion	978	1,403	1,084	1,003	1,003	1,003	1,003
Oil and Gas Activities	302	318	487	610	610	610	610
<i>International Bunker Fuels^a</i>	<i>103</i>	<i>133</i>	<i>136</i>	<i>137</i>	<i>133</i>	<i>129</i>	<i>135</i>
NMVOCs	12,620	7,191	7,464	7,759	7,449	7,139	6,830
Mobile Combustion	10,932	5,724	4,591	4,562	4,252	3,942	3,632
Oil and Gas Activities	554	510	2,205	2,517	2,517	2,517	2,517
Stationary Combustion	912	716	576	599	599	599	599
Waste Combustion	222	241	92	81	81	81	81
<i>International Bunker Fuels^a</i>	<i>57</i>	<i>54</i>	<i>56</i>	<i>51</i>	<i>46</i>	<i>41</i>	<i>42</i>

^a These values are presented for informational purposes only and are not included in totals.

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates for 1990 through 2014 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Emission estimates for 2012, 2013, and 2014 for non-EGU and non-mobile sources are held constant from 2011 in EPA (2015). Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual applications from various agencies.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's *Compilation of Air Pollutant Emission Factors, AP-42* (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9 International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing

the Framework Convention on Climate Change.⁸⁰ These decisions are reflected in the IPCC methodological guidance, including IPCC (2006), in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).⁸¹

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.⁸² Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO₂, CH₄ and N₂O for marine transport modes, and CO₂ and N₂O for aviation transport modes. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.⁸³

Emissions of CO₂ from aircraft are essentially a function of fuel use. Nitrous oxide emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Recent data suggest that little or no CH₄ is emitted by modern engines (Anderson et al. 2011), and as a result, CH₄ emissions from this category are considered zero. In jet engines, N₂O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2014 from the combustion of international bunker fuels from both aviation and marine activities were 104.2 MMT CO₂ Eq., or 0.3 percent below emissions in 1990 (see Table 3-63 and Table 3-64). Emissions from international flights and international shipping voyages departing from the United States have increased by 82.5 percent and decreased by 48.4 percent, respectively, since 1990. The majority of these emissions were in the form of CO₂; however, small amounts of CH₄ (from marine transport modes) and N₂O were also emitted.

Table 3-63: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (MMT CO₂ Eq.)

Gas/Mode	1990	2005	2010	2011	2012	2013	2014
CO₂	103.5	113.1	117.0	111.7	105.8	99.8	103.2
Aviation	38.0	60.1	61.0	64.8	64.5	65.7	69.4
<i>Commercial</i>	30.0	55.6	57.4	61.7	61.4	62.8	66.3
<i>Military</i>	8.1	4.5	3.6	3.1	3.1	2.9	3.1
Marine	65.4	53.0	56.0	46.9	41.3	34.1	33.8
CH₄	0.2	0.1	0.1	0.1	0.1	0.1	0.1

⁸⁰ See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

⁸¹ Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

⁸² Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

⁸³ Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

Aviation ^a	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N₂O	0.9	1.0	1.0	1.0	0.9	0.9	0.9
Aviation	0.4	0.6	0.6	0.6	0.6	0.6	0.7
Marine	0.5	0.4	0.4	0.4	0.3	0.2	0.2
Total	104.5	114.2	118.1	112.8	106.8	100.7	104.2

^a CH₄ emissions from aviation are estimated to be zero.

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-64: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2010	2011	2012	2013	2014
CO₂	103,463	113,139	116,992	111,660	105,805	99,763	103,201
Aviation	38,034	60,125	60,967	64,790	64,524	65,664	69,411
Marine	65,429	53,014	56,025	46,870	41,281	34,099	33,791
CH₄	7	5	6	5	4	3	3
Aviation ^a	0	0	0	0	0	0	0
Marine	7	5	6	5	4	3	3
N₂O	3	3	3	3	3	3	3
Aviation	1	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1

^a CH₄ emissions from aviation are estimated to be zero.

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-65: Aviation CO₂ and N₂O Emissions for International Transport (MMT CO₂ Eq.)

Aviation Mode	1990	2005	2010	2011	2012	2013	2014
Commercial Aircraft	30.0	55.6	57.4	61.7	61.4	62.8	66.3
Military Aircraft	8.1	4.5	3.6	3.1	3.1	2.9	3.1
Total	38.0	60.1	61.0	64.8	64.5	65.7	69.4

Notes: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO₂ were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under Section 3.1 – CO₂ from Fossil Fuel Combustion. Carbon content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2016) and USAF (1998), and heat content for jet fuel was taken from EIA (2016). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.8 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH₄ and N₂O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH₄ and N₂O emissions were obtained from the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.1 for N₂O (IPCC 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH₄ and 0.08 for N₂O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 1990, 2000 through 2014 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the *2006 IPCC Guidelines* (IPCC 2006).

International aviation CO₂ estimates for 1990 and 2000 through 2014 are obtained from FAA's AEDT model (FAA 2016). The radar-informed method that was used to estimate CO₂ emissions for commercial aircraft for 1990, and 2000 through 2014 is not possible for 1991 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. Because fuel consumption and CO₂ emission estimates for years 1991 through 1999 are unavailable, consumption estimates for these years were calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through 2013), adjusted based on 2000 through 2005 data.

Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data from DoD's Defense Logistics Agency Energy (DLA Energy 2015). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-66. See Annex 3.8 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 2015) for 1990 through 2001, 2007 through 2014, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DLA Energy (2015). The total amount of fuel provided to naval vessels was reduced by 21 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-67.

Table 3-66: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	2005	2010	2011	2012	2013	2014
U.S. and Foreign Carriers	3,222	5,983	6,173	6,634	6,604	6,748	7,126
U.S. Military	862	462	367	319	321	294	318
Total	4,084	6,445	6,540	6,953	6,925	7,042	7,445

Note: Totals may not sum due to independent rounding.

Table 3-67: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2010	2011	2012	2013	2014
Residual Fuel Oil	4,781	3,881	4,141	3,463	3,069	2,537	2,466
Distillate Diesel Fuel & Other	617	444	476	393	280	235	261
U.S. Military Naval Fuels	522	471	448	382	381	308	331
Total	5,920	4,796	5,065	4,237	3,730	3,081	3,058

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.⁸⁴ For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO₂ in the *2006 IPCC Guidelines* (IPCC 2006) is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC also

⁸⁴ See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO₂.⁸⁵

There is also concern regarding the reliability of the existing DOC (2015) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO₂, CH₄, and N₂O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Planned Improvements

The feasibility of including data from a broader range of domestic and international sources for bunker fuels, including data from studies such as the Third IMO GHG Study 2014, is being considered.

3.10 Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol generates CO₂ in addition to CH₄ and N₂O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO₂ emissions from biomass combustion have been estimated separately from fossil fuel CO₂ emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 6), which accounts for the contribution of any resulting CO₂ emissions to U.S. totals within the Land Use, Land-Use Change, and Forestry sector's approach.

In 2014, total CO₂ emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 217.7 MMT CO₂ Eq. (217,654 kt) (see Table 3-68 and Table 3-69). As the largest consumer of woody biomass, the industrial sector was responsible for 57.1 percent of the CO₂ emissions from this source. The residential sector was the second largest emitter, constituting 27.5 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

⁸⁵ U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Table 3-68: CO₂ Emissions from Wood Consumption by End-Use Sector (MMT CO₂ Eq.)

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Industrial	135.3		136.3		119.5	122.9	125.7	123.1	124.4
Residential	59.8		44.3		45.4	46.4	43.3	59.8	59.8
Commercial	6.8		7.2		7.4	7.1	6.3	7.2	7.6
Electricity Generation	13.3		19.1		20.2	18.8	19.6	21.4	25.9
Total	215.2		206.9		192.5	195.2	194.9	211.6	217.7

Note: Totals may not sum due to independent rounding.

Table 3-69: CO₂ Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Industrial	135,348		136,269		119,537	122,865	125,724	123,149	124,369
Residential	59,808		44,340		45,371	46,402	43,309	59,808	59,808
Commercial	6,779		7,218		7,385	7,131	6,257	7,235	7,569
Electricity Generation	13,252		19,074		20,169	18,784	19,612	21,389	25,908
Total	215,186		206,901		192,462	195,182	194,903	211,581	217,654

Note: Totals may not sum due to independent rounding.

The transportation sector is responsible for most of the ethanol consumption in the United States. Ethanol is currently produced primarily from corn grown in the Midwest, but it can be produced from a variety of biomass feedstocks. Most ethanol for transportation use is blended with gasoline to create a 90 percent gasoline, 10 percent by volume ethanol blend known as E-10 or gasohol.

In 2014, the United States consumed an estimated 1,111.3 trillion Btu of ethanol, and as a result, produced approximately 76.1 MMT CO₂ Eq. (76,075 kt) (see Table 3-70 and Table 3-71) of CO₂ emissions. Ethanol production and consumption has grown significantly since 1990 due to the favorable economics of blending ethanol into gasoline and federal policies that have encouraged use of renewable fuels.

Table 3-70: CO₂ Emissions from Ethanol Consumption (MMT CO₂ Eq.)

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Transportation ^a	4.1		22.4		71.3	71.5	71.5	73.4	74.8
Industrial	0.1		0.5		1.1	1.1	1.1	1.2	1.0
Commercial	+		0.1		0.2	0.2	0.2	0.2	0.3
Total	4.2		22.9		72.6	72.9	72.8	74.7	76.1

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2, Table A-94 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Table 3-71: CO₂ Emissions from Ethanol Consumption (kt)

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Transportation ^a	4,136		22,414		71,287	71,537	71,510	73,359	74,810
Industrial	56		468		1,134	1,146	1,142	1,202	987
Commercial	34		60		226	198	175	183	277
Total	4,227		22,943		72,647	72,881	72,827	74,743	76,075

^a See Annex 3.2, Table A-94 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2016) (see Table 3-72), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO₂ emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO₂ with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2016) (see Table 3-73).

Table 3-72: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Industrial	1,441.9	1,451.7	1,273.5	1,308.9	1,339.4	1,312.0	1,325.0
Residential	580.0	430.0	440.0	450.0	420.0	580.0	580.0
Commercial	65.7	70.0	71.6	69.2	60.7	70.2	73.4
Electricity Generation	128.5	185.0	195.6	182.2	190.2	207.4	251.3
Total	2,216.2	2,136.7	1,980.7	2,010.2	2,010.3	2,169.5	2,229.6

Note: Totals may not sum due to independent rounding.

Table 3-73: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation	60.4	327.4	1,041.4	1,045.0	1,044.6	1,071.6	1,092.8
Industrial	0.8	6.8	16.6	16.7	16.7	17.6	14.4
Commercial	0.5	0.9	3.3	2.9	2.6	2.7	4.1
Total	61.7	335.1	1,061.2	1,064.6	1,063.8	1,091.8	1,111.3

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values for 2013 were revised relative to the previous Inventory based on updated information from EIA's *Monthly Energy Review* (EIA 2016). These revisions of historical data for wood biomass consumption resulted in an average annual increase in emissions from wood biomass consumption of 0.1 MMT CO₂ Eq. (less than 0.1 percent) from 1990 through 2013. Ethanol consumption values remained constant relative to the previous Inventory throughout the entire time-series.

Planned Improvements

The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.⁸⁶ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from biomass combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO₂ emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁸⁷

⁸⁶ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

⁸⁷ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

Exhibit 2



**AIR EMISSIONS INVENTORY
ESTIMATES
for a REPRESENTATIVE OIL and GAS
WELL in the WESTERN
UNITED STATES**

March 25, 2013

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PREPARED.**



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**AIR EMISSIONS INVENTORY ESTIMATES
for a REPRESENTATIVE OIL and
GAS WELL in the WESTERN
UNITED STATES**

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March 25, 2013

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APPENDICES

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- Appendix B: Emission Inventory for the Uinta/Piceance Basin Gas Well
- Appendix C: Emission Inventory for the Upper Green River Basin Gas Well
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1 EXECUTIVE SUMMARY

The Bureau of Land Management National Operations Center (BLM NOC) retained the Kleinfelder Team (which consists of staff from Kleinfelder, Inc. and ENVIRON International Corporation) to prepare an emissions inventory estimate of criteria pollutants, greenhouse gases (GHG), and key hazardous air pollutants (HAPs) for a representative oil and gas well in the western United States (US). The emissions inventory is designed to be used by BLM staff, such as NEPA planners, air resource specialists, and natural resource specialists, to evaluate emissions from small, which for purposes of this inventory is approximately five wells or less, oil and gas projects.

Defining a “representative” oil and gas well for the entire western US is extremely challenging as there are numerous variables, even within a single basin and sub basin that can materially affect the emissions. Such variables include oil and gas composition, difficulty drilling the geologic formation, oil and gas production rate, equipment at the well site, emission controls, produced water that may be associated with oil and gas production, among many others. Accordingly, to develop such an inventory, five different well types (three natural gas wells and two oil wells) representative of five different major oil and gas basins in the western US were evaluated. Figure 1-1, located at the end of this section, shows the major oil and gas producing basins in the western US. In order to develop the emission inventories, information that is not proprietary, not draft, and not pre-decisional was reviewed for the five selected basins plus other oil and gas developments in the western US. The information sources are discussed in Section 2 of this report. The characteristics of the five basins selected are similar to a large portion of the oil and gas produced in the western United States. The five well types and key characteristics are shown Table 1-1 on the next page.

An Excel workbook that provides the detailed and summary of the emission estimates was prepared. The Workbook is interactive, allowing the user to choose one of the five well types based on basin characteristics for the project of interest. Once the well type is selected, the Excel Workbook is automatically populated with the key variables. The electronic version of the Excel Workbook is included as Appendix A. Appendices B through F include printouts of the Excel Workbook for each of the five well types. Table 1-2 presents the summary emission inventory estimate results. Except for sulfur dioxide (SO₂), ethylbenzene, and nitrous oxide

(N₂O), the values in Table 1-2 are rounded to one decimal place. Global warming potential (GWP) is rounded to a whole number. The number of significant figures shown in Table 1-2 varies as the quantity of individual pollutants is highly variable. For example, SO₂ emissions are reported to only one significant figure because the emissions are on the order of one ten thousandth of a ton per year. But GWP is reported to 5 significant figures because emissions are in the thousands of tons per year.

**TABLE 1-1
CHARACTERISTICS OF SELECTED REPRESENTATIVE BASINS**

Product	Basin	Key Characteristics
Gas well	Uinta/Piceance	Deep wells which may include shale, dry gas, moderate condensate production
Gas well	Upper Green River	Deep wells, multiple devices per well, high condensate production, wet gas
Gas well	San Juan	Shallow wells, low amounts of condensate production, dry gas
Oil well	Williston	Shale formation, very deep wells, long horizontal drilling, high amounts of associated gas, associated gas flared
Oil well	Denver	Shallow wells, lower amounts of associated gas, associated gas sent to a sales line

**TABLE 1-2
SUMMARY OF EMISSION ESTIMATES FOR A SINGLE OIL OR GAS WELL**

Well Type:	Gas	Gas	Gas	Oil	Oil
Pollutant	Uinta/ Piceance (tpy)	Upper Green River (tpy)	San Juan (tpy)	Williston (tpy)	Denver (tpy)
NO _x	15.6	14.6	5.6	15.6	6.3
CO	3.8	3.9	3.1	8.0	3.4
VOC	3.4	5.2	5.3	17.6	6.7
SO ₂	0.0004	0.0004	0.001	0.001	0.001
PM ₁₀	6.9	6.7	6.8	6.9	6.6
PM _{2.5}	0.8	0.8	0.5	0.8	0.5
CO ₂	2,552.1	2,882.1	651.9	3,156.4	1,049.0
CH ₄	12.2	14.1	6.1	16.6	1.8
N ₂ O	0.05	0.05	0.04	0.6	0.04
GWP	2,825	3,194	791	3,682	1,099
Benzene	1.4	1.5	1.4	1.5	1.4
Toluene	1.0	1.2	1.0	1.0	1.0
Ethylbenzene	0.00003	0.01	0.0008	0.0008	0.0006
Xylene	0.6	0.7	0.6	0.6	0.6
n-Hexane	7.5	7.5	7.5	7.9	7.5
Total HAPs	10.4	10.9	10.5	11.0	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported. Greenhouse gas emissions are in terms of short tons CO₂, CH₄, and N₂O. Global Warming Potential (GWP) is in terms of short tons of CO₂ equivalent (CO₂e), using a GWP of 1 for CO₂, 21 for CH₄, and 310 for N₂O.

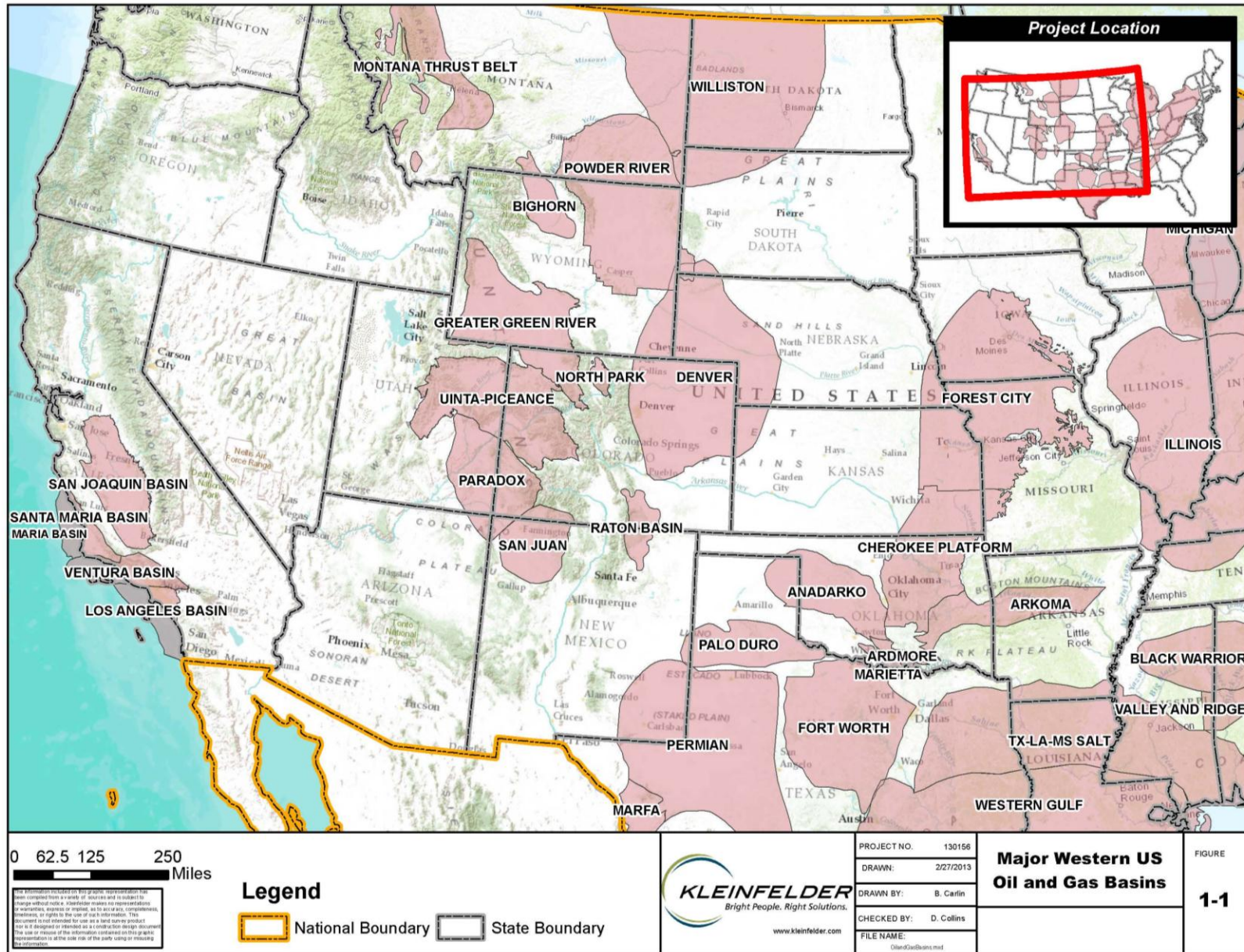
Emission estimates can be calculated as annual average emissions, worst-case single year emissions, or some other scenario. The various methods of representing emissions are problematic since a project could involve simultaneous construction and development (drilling and fracturing) and operation (production) in the same location, which is further complicated since well production is not a constant. Therefore, the worst-case emission estimate is to assume that construction, development, and operation occur simultaneously as shown in Table 1-2. If the user is interested in maximum operation-only emissions, then the tables in Section 3.3 of this report can be consulted where emissions from the three activities are reported separately.

As discussed in Sections 3.2.5 and 3.2.6 of this report, the emission calculations do not account for the fact that over time oil and gas well production rates decrease, i.e., the decline curve or decline factor. If one wanted a life-time average emission rate for production operations, a decline factor would have to be applied to the emission estimates in the tables of this report. To estimate lifetime average emissions, one can assume that operational emissions are linearly related to production and thus a linear application of the decline factor to the emissions can be used (i.e., if the decline factor is 50 percent, the lifetime average emissions would be 50 percent of those presented herein for operation). Note that the decline factor is not applied to construction or drilling emissions.

The electronic version of the Excel Workbook in Appendix A allows the user to enter project-specific variables that will over-ride the default values incorporated into the Workbook. Project variables are entered into a single “Constants and References” tab in the Workbook, and the changes automatically populate the remaining tabs and calculations. (The user should not enter the over-ridden value directly into the individual emission calculation sheets, but rather into the “Constants and References” sheet.)

In this document, the emission estimates are reported as a single value for each pollutant and well type rather than a range of values. However, Section 3 presents the range of key parameters evaluated and the basis for the selected single parameter. If the user wants to consider a range of emission estimates for a specific project, the range of key parameters shown in Section 3 or any other range of parameters can be entered into the Excel Workbook and a range of emission estimates easily generated.

The remaining sections of this report describe the methodology, references, and regulatory analyses used to develop the emission estimates in Section 2. Section 3 presents the parameters selected and results of the emission inventories. Sections 4 and 5 present conclusions and limitations. Section 6 provides a list of references used in the study.



2 EMISSION INVENTORY ESTIMATING METHODOLOGY AND REFERENCES

In order to develop the emission inventory estimates for representative oil and gas wells, an eight step process was used. The steps are as follows:

1. Identify active oil and gas basins in the western US.
2. In concert with BLM (Mr. Dave Maxwell of the National Operations Center), select those basins within which there are significant BLM lands and BLM interest in developing emissions inventories.
3. Identify basins that have significant oil and gas development and are representative of the BLM basins of interest.
4. Obtain National Environmental Protection Act (NEPA) Environmental Impact Statements (EISs) and Environmental Analyses (EAs), Resource Management Plans (RMPs), site-specific air permit applications, and other information that provide parameters and emission inventories for the basins selected, including reviewing the literature related to emission estimating techniques, such as United States Environmental Protection Agency (USEPA) publications.
5. From the literature and experience with development in the selected basins, select a representative collection of parameters necessary for estimating emissions for each basin.
6. Select appropriate emission estimating techniques and develop an Excel Workbook of emission estimates.
7. Evaluate the uncontrolled emission estimates against current federal and state regulations that could affect the emissions, and incorporate those emission controls required by regulations into the Excel Workbook as applicable.
8. Perform quality control/quality assurance checks on the Excel Workbook.

These steps will be further discussed in the following subsections.

2.1. SELECTION OF BASINS OF INTEREST AND REPRESENTATIVE BASINS

Most of the active oil and gas development in the western US occurs in the states of Alaska, California, Montana, North Dakota, Wyoming, Utah, Colorado, Nebraska, New Mexico, Texas,

Oklahoma, and Kansas. In concert with BLM (Mr. Dave Maxwell of the National Operations Center), it was decided that neither California nor Alaska would be included in the project and that the focus would be only on conventional and shale oil and gas (e.g., coal bed methane was excluded). There is relatively little active oil and gas BLM land in California and Alaska has its own program for developing emission inventories and thus were excluded. It was also decided that Texas, Oklahoma, and Kansas would be excluded as well-specific information for wells in these basins tends to be proprietary to the operators. Although some information is available from state permit applications for wells, many of the activities that occur do not need a state permit or do not need a complete emissions inventory. Thus complete information for emissions inventories is not readily available. In addition, there is relatively less BLM controlled oil and gas lands in these Basins. Although the inventory can probably be used with relative confidence in Texas, Oklahoma, Kansas, or California if needed, it should not be used in Alaska because of the unique environment in that area.

For the remaining states, the major producing basins within which there is a relatively large amount of public land are the Williston, Upper Green River, Uinta, Piceance, Denver, San Juan, and Permian basins. These basins are responsible for a large portion of the oil and gas production in the western US that occurs on public lands. The Uinta and Piceance Basins are next to each other and have similar oil and gas geologic formation and production characteristics. Therefore, for purposes of the emission inventories, the Uinta and Piceance Basins were combined. The Permian Basin is also a major producing basin in southeast New Mexico and west Texas. Although this is a major basin, most of the development in Texas is on non-BLM land, and in New Mexico, BLM has already developed an emissions calculator for the Permian Basin. Therefore, the Permian basin was also excluded from this study. A map of the key oil and gas basins is shown in Figure 1-1 and a more detailed map is available from the US Energy Information Administration (EIA, 2013).

Therefore, the basins that were evaluated for this study are the Williston, Upper Green River, Uinta/Piceance, Denver, and San Juan. The Williston and Denver Basins are primarily oil plays, while the Upper Green River, Uinta/Piceance, and San Juan Basins are primarily natural gas plays. This does not mean that there could not be oil wells in the Upper Green River, Uinta/Piceance, or San Juan Basins or gas wells in the Williston and Denver Basins. But for purposes of the emission inventories, the representative wells were selected based on the primary play of that basin.

The key characteristics of the basins that are relevant for purposes of the emissions inventory are as follows. These characteristics are extremely generalized and actual conditions vary widely even within the same basin.

- Uinta/Piceance. Gas wells in this basin may or may not be drilled into a shale formation, but tend to be deep wells (on the order of 15,000 feet), are difficult to drill, and drill rigs are on a single well pad for a relatively long duration. There is not much water present in the gas, so no dehydrators are normally required at the well site. The gas wells produce a moderate amount of condensate (light oil). Equipment at the well site tends to be simple, with a single separator and a condensate tank. Although there are compressors used in the Basin to move gas to market, the compressors are not at well sites and are not included in the emission inventories.
- Upper Green River. Gas wells in the Upper Green River Basin also tend to be deep (on the order of 15,000 feet) but are drilled into non-shale formations. The gas tends to have more condensate (oil) present than either the San Juan or Uinta/Piceance Basins. There is more water vapor present in the gas from this Basin than others, so there normally is a dehydrator at each well site. The well sites also usually contain a separator and line heater. Wells are drilled at a relatively high density. There are gas compressors in the Basin used to move the gas to market. However, these compressors are not located at a well site.
- San Juan. Some gas wells in the San Juan basin may contain relatively high volumes of liquid water and thus pumpjack engines may be present (to remove the water) even though the wells are gas wells. San Juan gas wells produce relatively little condensate, thus there may not be any condensate tanks present. The wells tend to be shallow (on the order of 5,000 feet) and there is a minimal amount of equipment on site. For purposes of this study, the emission inventory includes a pumpjack engine and a condensate tank, even though they may not be present at all San Juan well types. As is the case for the Upper Green River Basin, gas compressors are used in the Basin, but are not generally located at a well site.
- Williston. Oil wells in the Williston Basin tend to be very deep (on the order of 15,000 to 18,000 feet), and are drilled into a shale formation that is difficult to drill, thus drill rigs are

on site for a relatively long time. Horizontal drilling in the Williston Basin can be very long, on the order of a mile or more away from the well pad. The Williston formation is relatively very thin, and thus precise drilling is required. There is a relatively large amount of gas associated with the oil wells, and the gas may be flared in a flare pit for a period of time before it can be sent to a sales line.

- Denver. The Denver Basin is the easiest to drill, with relatively shallow wells (on the order of 5,000 feet deep) in non-shale formations. There are relatively low amounts of gas associated with the oil wells and that gas is sent to a sales line. The Denver Basin oil tends to be lighter than the Williston Basin.

Note that the oil and gas wells in these basins tend to be sweet wells (i.e., there is no or very little hydrogen sulfide associated with the wells). However, any of the wells in any of the basins could be sour wells with relatively large amounts of hydrogen sulfide (H_2S). For purposes of the emissions inventory, it was assumed that the wells were all sweet wells with no H_2S . However, if it is known that the project-specific wells are not sweet wells, then a project-specific H_2S concentration can be input in the Excel Workbook and the Workbook will calculate potential H_2S emissions. If the amount of H_2S is significant, the project may be required to install H_2S emission controls (e.g., a sweetening unit). The effectiveness of a sweetening unit and emissions from it are beyond the scope of this study, but would have to be accounted for in an emissions inventory if present. Since H_2S can be an important issue, the Excel Workbook will calculate emissions of it, even though it is not a criteria pollutant or a HAP. The Excel Workbook also accounts for emissions of SO_2 from combustion of gas if the gas contains H_2S .

2.2. LITERATURE AND REFERENCES

Once the basins were selected, several sources of information were consulted in order to determine representative emission calculation parameters. Generally accepted emission estimating techniques published by the USEPA were used for the emission calculations. However, those techniques require a number of parameters in order to yield emissions. The parameters were obtained from NEPA documents, RMPs, air permits to construct, and professional judgment. USEPA publications are peer reviewed and generally accepted for emission estimating techniques. On the other hand, individual parameters needed to calculate the emissions are not generally available in peer reviewed literature, but are detailed in the NEPA documents, RMPs, and permits to construct. Those major documents used for this

study, although not from scientific peer reviewed journals, were subjected to extensive stakeholder, state, and cooperating agency reviews. Therefore, those publications are suitable as the source of key oil and gas parameters needed for calculating emissions. Section 3 of this report discusses the key parameters and the source of the parameters selected, and Section 6 presents a list of references. The key sources of information for each of the basins are summarized below:

- Uinta/Piceance: Greater Natural Buttes EIS (BLM, 2012a), GASCO EIS (BLM, 2011b), White River RMP (BLM, 2012b), and the Colorado River Valley RMP (BLM, 2011a).
- Upper Green River: Jonah Infill EIS (BLM, 2006), Supplemental FEIS for the Pinedale Anticline (BLM, 2008), Wyoming air permits to construct
- San Juan: Farmington RMP (BLM, 2003)
- Williston. North Dakota air permits to construct and experience with the basin.
- Denver: Colorado air permits to construct and experience with the basin

As indicated, the above references are not the only literature sources used to select representative parameters, and the parameters in these sources were not used without judgment. In other words, the parameters contained in the above publications were evaluated and a representative value chosen based on professional judgment. No attempt was made to perform a statistical analysis of the parameters or choose an average or median from the references. The focus was on selecting representative parameters typical for the well type, not an average, or a conservative “worst case” value. The results of the parameter selection and the basis for the selection are discussed in Section 3 of this report. The equations and emission models used to estimate emissions are shown in the Appendices. The equations and models are those promulgated by the USEPA in such publications as AP-42, *Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* (USEPA, 2013).

The specific references examined and the source of those references is listed below. Each of the key references has been assigned an abbreviation which is shown below in quotes, and which is used throughout the remainder of this report. The specific information obtained and used from each reference is discussed in Section 3 of this report.

- “NDDEQ”: Well site air quality permit to construct applications filed and approved for Helis Oil and Gas Company, LLC (3 sites), Prima Exploration, Inc. (2 sites), Samuel Gary Jr. and Associates, Inc. (2 sites) and G3 Operating, Inc. (3 sites). Available through a public records request to the North Dakota Department of Environmental Quality.
- “CDPHE”: Ten well site air quality permits to construct applications filed and approved for Bayswater Exploration and Production, LLC. Available through a public records request to the Colorado Department of Health and Environment Air Pollution Control Division.
- “WYDEQ”: Well site air quality permit to construct applications filed and approved for Helis Oil and Gas Company, LLC (4 sites), Enduro Operating, LLC (2 sites), and Samson Oil and Gas Ltd. (6 sites) Available through a public records request to the Wyoming Department of Environmental Quality Air Quality Division.
- “Farmington RMP”: Farmington Resource Management Plan and Final Environmental Impact Statement, March 2003 (BLM, 2003).
- “White River”: White River Field Office Oil and Gas Resource Management Plan Amendment / Environmental Impact Statement Air Resources Technical Support Document, June 2012 (BLM, 2012b).
- “Jonah”: Final Air Quality Technical Support Document for the Jonah Infill Drilling Project Environmental Impact Statement, January, 2006 (BLM, 2006).
- “Pinedale”: Supplemental Final Environmental Impact Statement for the Pinedale Anticline Project Area, June, 2008 (BLM, 2008).
- “CRV”: Final Colorado River Valley Field Office Resource Management Plan Revision, Air Resources Technical Support Document, Revised August 2011 (BLM, 2011a).
- “GNB”. Greater Natural Buttes Final Environmental Impact Statement, FES 12-8, March 2012 (BLM, 2012a).
- “GASCO”: Final Environmental Impact Statement (EIS) for the GASCO Uinta Basin Natural Gas Development Project, 2011 (BLM, 2011b).

Note that the above documents are mostly BLM publications. Although other publications were also evaluated, such as EISs published by the Bureau of Indian Affairs (BIA 2012a, BIA 2012b), because most of the public lands with oil and gas resources are in the western US and are controlled by BLM, the BLM EIS and RMP publications tend to be the most detailed and useful for this study.

The above publications and references provided project-specific detail and calculations for individual well activities, and thus were the most useful. There are other publications and information sources that were also reviewed, such as the Western Regional Air Partnership (WRAP) emissions databases (WRAP, 2013), the West-wide Jumpstart Air Quality Modeling Study (WRAP, 2013), the USEPA National Emissions Inventory (USEPA, 2013), and the USEPA Greenhouse Gas Reporting Program (GHGRP) emissions inventories (USEPA, 2011). However, these databases and information sources provide emissions on a facility-wide, company-wide, or regional basis and do not provide individual well-specific information suitable for use in the emissions inventories which are the subject of this study. On the other hand, the information in those databases were evaluated and compared to the emission estimating techniques and parameters used in this study as an overall confirmation that the individual well inventories are consistent with the facility and company-wide data and that consistent emission estimating techniques were used.

In addition to the above publications and permit applications, state regulations for the western US that could affect the emission inventories were also reviewed. This review is discussed in Section 2.5 of this report.

2.3. EMISSION CALCULATIONS

The parameters selected from the above references and professional judgment were then input into an Excel Workbook in order to calculate the emissions for each of the five representative basins. The Excel Workbook is contained in Appendix A, hard copies for each basin are shown in Appendices B through F, and a discussion of the key parameters and reason for selection is presented in Section 3 of this report. The Appendices also present the equations, emission models, and emission factors used to calculate the emissions and details for each of the individual emitting activities.

2.4. QUALITY CONTROL/QUALITY ASSURANCE OF THE EMISSION CALCULATIONS

As the Appendices show, the emission calculations involve a large number of activities, a large number of emission estimating techniques and parameters, and the parameters vary by well type. Quality Control/Quality Assurance (QC/QA) of the spreadsheets was conducted through

independent (i.e., Kleinfelder Team staff who were not involved in the initial calculations) review of the estimating techniques, the parameters chosen, application of the parameters, and the emission calculations. The equations in the Excel Workbook were subjected to hand-calculation to confirm the value calculated electronically. Visual inspection was used to confirm population of the variables from the “Constants and References” tab of the Workbook throughout the appropriate equations. Selection of emission parameters for each well type was reviewed by engineers familiar with oil and gas operations but who were not involved in the initial selection. Finally, the emission totals were compared to other emission totals from other publications and projects to confirm representativeness.

2.5. STATE AND FEDERAL REGULATIONS

The final step was to evaluate state and federal regulations that could affect the emission calculations for isolated wells which are the subject of this study. For example, the new New Source Performance Standard (NSPS) for oil and gas production (40 CFR Part 60 Subpart OOOO) requires emission controls on condensate/oil tanks if the uncontrolled emissions are greater than 6 tons per year. In parallel with the NSPS, there are also National Emission Standards for Hazardous Air Pollutants (NESHAPs) that could apply to oil and gas wells, e.g., 40 CFR 63 Subpart HH.

The regulations evaluated and how they affect the emission calculations are summarized below. Only those portions of the regulations that could change the emissions inventory for the situation where there are a few isolated wells are noted. There are numerous federal and state regulatory requirements that could apply to large stationary and mobile sources or groups of sources, but it is beyond the scope of this study to present all of those regulatory requirements.

2.5.1. Federal NSPS

The primary federal regulation that affects individual wells is the NSPS for the Oil and Gas Sector (40 CFR 60 Subpart OOOO). Subpart OOOO (and 40 CFR 60 Subpart VVa which is referenced by Subpart OOOO as a requirement) could affect well emissions through the following requirements:

- The NSPS requires control of flowback emissions (associated natural gas) that could occur during the hydraulic fracturing process. Therefore, in this study it was assumed

that hydraulic fracturing flowback emissions during well development would be controlled to the 95 percent level. However Subpart OOOO does not require control of flowback emissions during workovers, and thus no control during workovers was assumed.

- All storage tanks for oil or condensate are required to be controlled with a minimum of 95 percent efficiency if the uncontrolled VOC emissions are more than 6 tons per year. For the wells evaluated in this study, the storage tank VOC emissions from wells in all of the Basins except the San Juan were assumed to have uncontrolled emissions greater than 6 tons per year, and were controlled. (As discussed in Section 2.4.3, storage tanks in the Denver Basin are required to be controlled with a minimum of 70 percent efficiency even if uncontrolled emissions are less than 6 tons per year. However, in this study, uncontrolled VOC emissions for the Denver Basin oil well are greater than 6 tons per year, and the Subpart OOOO requirement of 95 percent control was applied to the Denver Basin well type).
- The NSPS requires, beginning October 15, 2013, that all pneumatic controllers on new wells emit less than 6 standard cubic feet per hour (scf/hr) of natural gas (generally termed “low bleed” pneumatics) unless high bleed pneumatic controllers are required for safety or other justifiable operational requirements. Accordingly, for purposes of the emission inventory, it was assumed that all pneumatic controllers were low-bleed. Other pneumatic devices (e.g. dump valves and pumps) do not have the low bleed requirement.

The second NSPS affecting emissions from single well sites is the NSPS for stationary spark ignition reciprocating engines, 40 CFR 60 Subpart JJJJ. This NSPS only applies to the pumpjack engines in the emissions inventory as the other engines are either not stationary or are diesel-fueled compression ignition engines. (Subpart JJJJ also applies to reciprocating compressor engines, but as discussed, the emissions inventories do not include compressors since compressors are not located at individual well sites). The NSPS requires engines manufactured after July 1, 2008 to meet emission limits of 2.8 grams per horsepower hour (g/bhp-hr) NO_x and 4.8 g/bhp-hr CO for engines less than 100 horsepower (the pumpjack engines are smaller than 100 horsepower). For purposes of this study, it was assumed that the pumpjack engines would be model year 2008 or later and thus will meet the Subpart JJJJ emission limits.

In addition to the NSPS, there are federal regulations (40 CFR 89 and 40 CFR 1039) that require manufacturers of diesel-fueled engines used on the drill rig and drill platform to meet certain emission limits. The emission limits differ according to the size and year of manufacturer of the engine, with the most stringent limits being for engines manufactured after 2015 (i.e., large Tier 4 engines). However, older model year engines can continue to be used after 2015. For purposes of the emission inventories, it was assumed that drill rig engines would meet Tier 2 emission limits, i.e., limits for engines manufactured after 2001 for the smaller engines and after 2006 for the large drill rig engines over 750 horsepower. It was assumed that the remainder of the engines would not meet any specific emission limits (i.e., so-called Tier 0 engines). The emission limits on engines are complex and a complete description of the limits and alternatives is beyond the scope of this study. The engine emission limits also affect construction equipment and other tailpipe emissions; however, those emission limits are built into the USEPA NONROAD emission model used to select emission factors for that type of equipment.

2.5.2. Federal NESHAP

Federal NESHAPs can apply to major and non-major sources of hazardous air pollutants (HAPs). The individual wells in this study are not major sources of HAPs, and thus only the non-major provisions of the NESHAP apply (non-major sources of HAPs are termed “area sources”). There are two NESHAP provisions that apply to single well site area sources: Subpart HH and Subpart ZZZZ. For area sources, Subpart HH only applies to dehydrators that process more than 3 million cubic feet per day of natural gas or have benzene emissions greater than 1 ton per year. It was assumed that all of the gas wells in this study produce 4 million cubic feet per day of natural gas, and thus it was assumed that dehydrators, if present, would be controlled to a minimum of 95 percent efficiency.

40 CFR 63 Subpart ZZZZ applies to both stationary spark ignition and stationary compression ignition engines, called reciprocating internal combustion engines (RICE). For this study, the only stationary RICE is the pumpjack engine, (because compressors are not included in the inventory), and in that case, for the small pumpjack engines, compliance with Subpart ZZZZ is met by complying with Subpart JJJJ as discussed previously.

2.5.3. State Regulations

The key state regulations that could affect the emission inventory are summarized below. As in the case with the federal regulations, the following is not a complete list of all of the compliance obligations that individual well sites may have to meet, but rather only a brief summary of those regulations that could meaningfully affect the emission calculations. State requirements must be at least as stringent as Federal requirements, and in some cases are more stringent. For completeness, even when the state requirements are not more stringent than the federal requirements, the requirements are summarized below. Section 6 of this report identifies where the regulations discussed for each state can be obtained.

Montana

Montana requires sites where uncontrolled emissions from oil or condensate tanks or loading operations have the potential to emit VOCs greater than 15 tons per year to be controlled. The Federal 40 CFR 60 Subpart OOOO requires controls at 6 tons per year. For purposes of this emissions inventory, all of the oil or condensate tanks in all of the basins except for the San Juan Basin were assumed to have uncontrolled emissions greater than 6 tons per year, and thus emission controls were included in the emissions inventory for the Williston Basin well type. Montana regulations require submerged filling during loading operations, but this type of emission control has been included in all of the emission inventories because it is standard practice.

Montana requires stationary internal combustion engines over 85 horsepower to install oxidation catalytic reduction (or similar controls) to reduce emissions of NO_x and CO (Montana Regulation ARM Title 17, Chapter 8, Subchapter 16, Section 1603(e) and (f)). However, the stationary engines at the well sites, i.e., the pump jack engines, are smaller than 85 horsepower, so no additional controls were included in the emission inventory.

North Dakota

North Dakota requires all sites with the potential to emit 20 tons per year or greater of VOCs from the storage tanks, including produced water tanks, to control vapors from the tanks by at least 98 percent control efficiency. For those sites where the vapors from storage tanks have the potential to emit less than 20 tons per year of VOCs, the tanks at those sites need to be

controlled by at least 90 percent control efficiency. However, the Federal 40 CFR 60 Subpart OOOO requires 95 percent control at 6 tons per year, and thus 95 percent emission controls for wells in the Williston Basin were included in the emissions inventory.

North Dakota also requires vapors from dehydrator still vents that exceed the following emission levels to be routed to a control device: greater than or equal to 5.0 tons per year of any combination of HAPs or greater than or equal to 15.0 tons per year of VOCs. The dehydrators in this study do not have that level of emissions, thus no controls were included in the emission inventories.

As is the case in Montana, splash loading is not permitted in North Dakota, and submerged filling was assumed in the emission inventories.

South Dakota

No specific regulations are currently established that affect the emission inventories for well sites in South Dakota.

Wyoming

Due to the extensive oil and gas development in Wyoming over a number of years, there are a number of Wyoming state regulations that could affect the emission inventories. The requirements vary by location within the oil and gas basins.

For the Jonah-Pinedale Anticline Development (JPAD) Area, the following are required:

- Tank flashing: 98 percent control on all new and modified tanks if uncontrolled emissions are greater than 8 tons per year. Because this level of control is only for the JPAD, which is a subset of the Upper Green River Basin, it was assumed that only 95 percent control would apply to the Upper Green River Basin well type as that yields an upper bound emission estimate.
- Dehydration units: 98 percent control on all new and modified dehydrators. This level of control was included in the emissions inventory for the Upper Green River well type.
- Pneumatic pumps: 98 percent control requirement or closed loop system on all new natural gas operated pumps (heat trace or other pumps) or existing pumps at modified facilities. Pneumatic pumps (as opposed to pneumatic controllers) are not always

required for wells in the Upper Green River Basin, and more modern wells are using solar-powered pumps. However, for purposes of the emissions inventory, because control on pneumatic pumps is for the JPAD, which is a subset of the Upper Green River Basin, it was assumed that pneumatic pumps would be controlled. The San Juan and Uinta/Piceance gas well types also have pneumatic pumps, but no controls are required nor included in the emissions inventory.

- Pneumatic controllers: All new (post 2010) natural gas operated pneumatic controllers must be low or no bleed. Low bleed pneumatic controllers were assumed for the emissions inventory for the Upper Green River well type as well as the other two gas-well basins. Note that there are other pneumatic devices (e.g., dump valves) which are not required to be low bleed.
- Completions: Green completion permits required for all completions with goal of achieving 98 percent control of venting emissions or use of Best Management Practices (BMPs) where feasible. It was assumed for the emission inventory that there would be no BMP feasible for single well sites in a small project (i.e., less than 5 wells, which is the focus of this study), and, therefore, no controls were included.
- Well blowdowns: Well blowdowns are associated with non-routine maintenance activities (e.g., depressurization of a well to affect repair) and are not included in the emissions inventory. However, Wyoming regulations require the use of BMPs (e.g., limiting the duration of venting) to minimize emissions to the extent practical.
- Produced water tanks: 98 percent control requirement on all new and modified tanks in the JPAD area (a Wyoming specific requirement only for the JPAD area) if the VOC emissions are over 8 tons per year. However, when the potential emissions from the produced water tanks are calculated, none of the single well sites have this level of emissions and no control is included in the emissions inventory.

For the Concentrated Development Area (Carbon, Fremont, Lincoln, Natrona, Sublette (non-JPAD), Sweetwater, and Uinta Counties) the requirements are essentially the same as the JPAD area except that the controls must be in place for one year and then can be removed if emissions are less than 8 tons per year. However, the Subpart OOOO NSPS requires control at 6 tons per year. Therefore, for purposes of the emission inventory, none of the controls were removed.

The Wyoming statewide requirements, i.e., counties not in the JPAD or Concentrated Development Area, are similar to the JPAD requirements, although the thresholds are less stringent and there are no requirements on well completions or produced water tanks. The JPAD requirements on completions and produced water tanks did not affect the emissions inventories; therefore, there is no difference between statewide requirements and JPAD requirements with regard to the emission inventories in this study.

Colorado

The Colorado Department of Public Health, Air Pollution Control Division, also has extensive regulatory requirements for oil and gas wells, depending on the area within which the well is located.

In the Front Range, Denver-Julesburg Basin (i.e., the North Front Range 8-hour ozone non-attainment area), the following are required:

- Tanks at the well site must achieve a minimum of 70 percent control during the non-ozone season and 90 percent control during the ozone season. However, for purposes of the emission inventory, uncontrolled VOC emissions were assumed greater than 6 tons per year. Thus 40 CFR 60 Subpart OOOO requires 95 percent control, and that level of control was applied.
- Pneumatic controllers installed after Feb. 1 2009 are required to meet the definition of a low-bleed controller. Subpart OOOO also requires low bleed controllers. However, for purposes of this study, it was assumed that there were no pneumatic controllers (low bleed or otherwise) present at the Denver Basin wells, as such devices are not normally present for oil wells. (No pneumatic devices were included for the Williston oil well type either).

The following are statewide requirements in Colorado:

- New and existing condensate tanks emitting 20 tons VOC per year or more are required to control emissions by 95 percent. Although none of the well sites in this study exceed that threshold, the federal threshold is 6 tons per year and 95 percent control was assumed.

- New and existing glycol dehydrators emitting more than 15 tons VOC per year or more are required to control, but none of the well sites in this study exceed that threshold.

In addition to the Air Pollution Control Division, the Colorado Oil and Gas Conservation Commission (COGCC) also has regulations that require emission controls on tanks and dehydrators with uncontrolled emissions over 5 tons per year, no or low-bleed pneumatics where feasible, and BMPs or green completions. As noted, tank controls and low-bleed pneumatic controllers are included in the emission inventories, but no BMPs that affect emissions were included, and it was assumed that associated gas entered the sales line.

Utah

There are no specific requirements for single well-site sources that would affect the emission inventories.

New Mexico

There are no specific requirements for single well-site sources that would affect the emission inventories.

Arizona

There are no specific requirements for single well-site sources that would affect the emission inventories, other than dust control requirements. Dust control has been included in the emissions inventories of this study.

Nevada

There are no specific requirements for single well-site sources that would affect the emission inventories.

Idaho

There are no specific requirements for single well-site sources that would affect the emission inventories.

Washington

There are no specific requirements for single well-site sources that would affect the emission inventories.

Oregon

There are no specific requirements for single well-site sources that would affect the emission inventories.

3 EMISSION INVENTORY ESTIMATE RESULTS

The emission inventories for the five representative basins are presented in Appendices A through F. The following sub-sections of this report discuss the activities included and excluded from the emission inventories and the results of the inventories by activity and pollutant.

3.1. EMISSION ACTIVITIES

The emission inventories include the following general activities. The specific detailed activities and equations for calculating emissions are shown in the Appendices. The general activities are as follows:

Construction (access road, pipeline, well pad)

- Fugitive dust from access road and well pad construction, interim and final reclamation, and construction heavy equipment
- Fugitive dust from pipeline construction
- Tailpipe and fugitive dust emissions from light duty vehicles (e.g., pickup trucks for construction workers), construction heavy equipment, and heavy duty trucks such as tanker trucks
- Wind erosion from disturbed surfaces

Development (drilling/completion/workovers)

- Tailpipe emission from engines used on the drill rig platform to install the conductor pipe
- Tailpipe emissions from engines associated with drilling the well, including drill rig, air compressors, electrical generators, and dozer and other heavy equipment engines
- Tailpipe emissions from hydraulic fracturing pump and associated engines (i.e., well completions)
- Well cementing emissions
- Well workover emissions
- Hydraulic fracturing flowback emissions
- Tailpipe and fugitive dust emissions from worker and delivery/transport vehicles

Operation (production of natural gas and oil)

- Well production emissions from heaters, pneumatic controllers, pumpjack engines, plus fugitive emissions (i.e., leaks from valves, flanges, open ended lines, etc.) at the well site
- Storage tank and loading emissions, including tailpipe and fugitive dust emissions from tanker trucks and other vehicles servicing the well
- Well-site dehydrators
- Tailpipe and fugitive dust emissions from worker and delivery/transport vehicles

Reclamation (included as part of Construction)

- Interim reclamation fugitive dust and tailpipe emissions, which are included as part of the well pad construction by adding vehicles and the duration of activities
- Final reclamation fugitive dust and tailpipe emissions, which are included as part of the well pad construction by adding vehicles and the duration of activities

No emission estimates were included for pipeline natural gas compressors and dehydrators not located at the well site, although pipeline compression and possibly pipeline dehydration will be required somewhere along a pipeline leading to a central gathering station and for moving the gas to market. But these emissions are not at a single well site.

Combustion emissions from flares that may be used to control potential emissions from storage tanks or dehydrators were included in the emissions inventory (as well as un-combusted VOCs and GHGs were included). If there is H_2S present in the flared gas, flare combustion can create SO_2 . For purposes of this study it was assumed that the wells did not contain meaningful amounts of H_2S , so no SO_2 emissions from flares were included. However, if the user of the inventory has information that there is meaningful amounts of H_2S present at a project, the user can enter the H_2S content of the gas and the Excel Workbook will calculate both the H_2S and SO_2 emissions resulting from combustion of gas containing H_2S . On the other hand, oil wells in the Williston Basin produce a large amount of associated gas, and that gas is flared in flare pits or other flare devices. The amount of associated gas can be considerable in the Williston Basin, thus the emissions inventory for the Williston Basin well type includes combustion emissions from flared associated gas.

Road maintenance emissions were not included in the emissions inventory, because this study focuses on projects that contain a small number of wells, typically wildcat or delineation wells.

In that that case, there may or may not be road maintenance activities and such activities are not at individual wells.

Some of the well sites in the San Juan Basin will have compressors located at the well head, but these compressors typically serve a group of gas wells even when located at a well site. However, for the wells which are the focus of this study (i.e., approximately five or fewer isolated wells), it is not likely that there would be well site compressor engines utilized. Therefore, no such engines were included in the emissions inventory, although field compression for a large group of wells somewhere in a large well field will be required in order to move the gas to market.

Two potential sources of VOC emissions are associated with liquids unloading (blowdowns) and working/breathing losses from storage tanks or mobile tanks. Working/breathing losses are much smaller than flashing emissions. The emissions inventory of this study was developed as a stand-alone document (and Excel Workbook) that could be used without additional emission estimating techniques. In order to calculate working and breathing losses, the USEPA TANKS emissions model would need to be used on a case by case basis. Working and breathing emissions are much smaller than flashing emissions and working and breathing losses could not be included without the user having to separately run the TANKS model (USEPA, 2012) on a case by case basis; therefore they have not been included in the inventory. Liquid unloading blowdowns are associated with a central facility. For the isolated few well scenario of this study, liquid unloading blowdowns would not likely be present and have thus not been included. Although unloading and working/breathing emissions can be meaningful when emissions from a large well field with thousands of wells are considered, in the case of the isolated wells which are the subject of this study, they are de minimis.

There may also be VOC emissions from drilling mud pits caused by hydrocarbons that may come up from the well during drilling. No emission factors were found in the references evaluated for this study, including no USEPA emission factors for this source. Accordingly, potential emissions from mud pits have not been included in the emission inventory.

The main activities producing meaningful amounts of HAPs typically associated with oil and gas drilling and production have been included in the emissions inventory. These HAPs are benzene, toluene, ethylbenzene, xylene (BTEX) and n-hexane. Tailpipe emissions of hazardous air pollutants from drill rig, hydraulic pump and similar engines and tailpipe emissions

of HAPs from on-road and off-road equipment have not been included as those emissions tend to be much smaller than HAPs associated with the oil and gas products. Some of the HAPs associated with tailpipe emissions are acetaldehyde, acrolein, benzene, 1,3-butadiene, and formaldehyde. These tailpipe emissions combined would constitute less than 0.3% of CO emissions, or on the order of 0.0008 tons per year in this emissions inventory. The percentage of tailpipe HAPs was derived from the I-15 Corridor Utah County to Salt Lake County FEIS, Table 3.8-8 (USDOT FHWA, 2008). Note that ethylbenzene emissions from oil and gas activities included in the emissions inventory are also relatively small, but ethylbenzene is one of the BTEX compounds associated with oil and gas production and it has been included in the emission inventory. Furthermore, some gas can contain larger amounts of benzene than the gas profiles used for the inventories in this study. If it is known that larger amounts of benzene are present, the project-specific gas composition can be entered into the Excel Workbook of Appendix A and the emissions will be automatically calculated.

In the Appendices, where a value of 0.00 appears, that indicates that there were no or de minimis emissions of that specific pollutant for that well type. If there are non-zero emissions, then at least one significant figure was reported. The number of significant figures shown in the Appendices varies as the quantity of individual pollutants is highly variable. For example, SO₂ emissions are reported to only one significant figure because the emissions are on the order of one ten thousandth of a ton per year. In the spreadsheets, the emission summaries are reported to two decimal places because in order to show a 0.00 value, two decimal places must appear in the Excel Workbook.

3.2. SELECTION OF PARAMETERS FOR EMISSION CALCULATIONS

The equations used to calculate the emissions for each of the above activities are shown on the spreadsheets in the Appendices. The equations use a combination of physical constants (e.g., conversion from meters to feet), variables required by the emission equations (e.g., moisture content of soil being moved), and well-specific parameters. The well-specific parameters are those parameters that were chosen to represent the five different well types that are the focus of this study. The basis for the physical constants, variables, and well-specific parameters are contained in the spreadsheets. The basis for most of the parameters are typical values based on professional judgment (e.g., 4 days to construct a well pad) and are generally used in all of the references discussed in Section 2.2 of this report. However, some of the well-specific parameters are more critical to the emissions estimates and required additional investigation

and judgment for selection. The critical well-specific parameters and the basis for selection are as follows. The terminology used for the references (e.g., "NDDEQ") is that presented in Section 2.2.

3.2.1. Vehicle Tailpipe and Fugitive Dust Emissions

Emissions associated with vehicle travel are a function of the emission factors (e.g., pounds per vehicle mile traveled, lb/VMT) and the number of miles traveled. The VMT is a function of the location and spacing of the wells, number and type of equipment and supply deliveries, number of workers, duration and magnitude of hydraulic fracturing, size of trucks bringing supplies (especially water) to the well, oil and condensate production rate of the well, size of the tanker trucks pumping the stock tanks, and numerous other variables. For purposes of the emission inventory, typical vehicle traffic counts and distances were used for wells drilled where there is relatively little hydraulic fracturing fluid needed. If project specific information is available for calculating project specific VMT (e.g., it is known that very large amounts of water will be needed for hydraulic fracturing), that information can be entered into the Workbook.

3.2.2. Drill Rig Engine Size

Drill rig and hydraulic fracturing pump engine horsepower vary widely among various inventories and studies, depending on the specific engines used by the drilling and production company and how quickly the drilling company intends to complete a well. GNB uses a drill rig engine of 1,476 horsepower (hp) and a completion rig of 475 hp. Jonah used 2,100 hp total for three engines when vertical drilling and 2,600 hp when horizontal drilling. Pinedale drill rig engines range from 3,640 to 4,040 hp. CRV used 2,952 hp for drill rig engines. For purposes of this emission inventory, the following drill rig engine sizes were assumed:

- Uinta/Piceance Drill Rig Engine 2,950 hp (i.e., the CRV value)
- Upper Green River Drill Rig Engine 2,100 hp (i.e., the Jonah value)
- San Juan Drill Rig Engine 2,100 hp (i.e., the Jonah value)
- Williston Drill Rig Engine 2,100 hp (i.e., the Jonah value)
- Denver Drill Rig Engine 2,950 hp (i.e., the CRV value)

The horsepower for other engines involved in drilling, hydraulic fracturing, and workovers (e.g., electrical generators, pump engines) are detailed in the Appendices. As shown in the

Appendices, hydraulic fracturing pump engines can also be relatively large, on the order of 1,500 horsepower.

The various reference documents either assume no load factor or variable load factors. For example, GNB used 65 percent load and 65 percent utilization for an overall load factor of 42 percent. For purposes of the emission inventory, two different load factors were used, depending on the operation and the engine. The 42 percent overall load factor was used for all engines except horizontal drilling and hydraulic fracturing pump engines. For those engines, a load factor of 59 percent was used, (90 percent load and 65 percent utilization), based on professional judgment, to reflect the fact that horizontal drilling and hydraulic fracturing are more power-intensive activities.

3.2.3. Drill Rig Engine Emission Limits

As discussed in Section 2.4.1, there are federal requirements for engine manufacturers to meet certain emission limits based on the “Tier” of the engine and date of manufacture. Various agency and EIS Records of Decision require more modern engines than federally required. For example, GNB required a minimum of Tier 2 engines, one of the alternatives evaluated in White River required Tier 4 engines, and Jonah required Tier 4 engines to be phased in between 2008 and 2015. Engines greater than 750 horsepower manufactured between 2011 and 2014 are required to meet interim Tier 4 emission limits while engines manufactured from 2015 and later are required to meet final Tier 4 emission limits. Turnover of the drill rig engine fleet to Tier 4 engines is dependent on individual rig operators; however, for purposes of the emissions inventory, Tier 2 engines were assumed. This provides a reasonable upper bound for the emissions from drill rig engines.

3.2.4. Hydraulic Fracturing Flowback Emissions

During hydraulic fracturing of the formation, the fracturing fluid is returned to the surface. This is termed “frac flowback.” The flowback can contain a meaningful amount of associated natural gas from the formation. In some cases, all of the associated gas is captured and either flared or sent to a sales line. When the flowback gas is completely captured and sent to a sales line, it is called a “green completion”. In other cases the associated gas is either flared or simply released to the atmosphere.

GNB assumed that all wells would be green completions with no flowback emissions. Jonah assumed that the flowback gas would be vented uncontrolled for 4 hours and flared for 80 hours with a total gas flowback amount of 35 thousand standard cubic feet (scf). CRV assumed that one-half the flowback gas would be vented uncontrolled and one-half flared, with a total flow of 1 million scf per well. Based on these references, for purposes of the emission inventory the CRV value of 1 million scf was used. The amount of flowback gas is highly variable and a function of the individual well, although for this study a constant value of 1 million scf was used. But as is the case with all variables, a different value can be input into the Excel Workbook if project-specific information is known. Consistent with 40 CFR Subpart OOOO and other regulations, it was assumed that all of the flowback gas was flared with 95 percent control.

3.2.5. Gas Production Rate, Decline Factor, and Dehydrator Emissions for Gas Wells

The gas production rate (standard cubic per day or scfd) of natural gas from an individual gas well is used to calculate potential dehydrator emissions. The anticipated production rate may be known, but the actual rate often varies greatly from the expected rate. For purposes of the emissions inventory, only the Upper Green River Basin well type has a dehydrator present.

Farmington RMP used an initial gas production rate of 55,584 Mscfd (55.6 MMscfd) per well but then applies a decline factor of 50 percent for the average life of the well (i.e., average production of 27.8 MMscfd). Pinedale used a gas production rate of 4,000 Mscfd (4.0 MMscfd) per well.

Both gas and oil wells initially produce much more on a daily basis than later in the life of the well. This is the decline factor or decline curve. Many of the reference documents do not specify a decline curve, either assuming that the initial production rate would remain constant or specifying an average production rate for the "life of the well", basically an average production rate over a period of 10 to 20 years. For purposes of the emission inventory in this study, no decline factor was built in to the emission estimates because the project-specific production rate is not known, and thus a decline factor is meaningless. Thus, the emission inventories provide an upper bound estimate of emissions based on the production rate specified.

Accordingly, a 4.0 MMscfd gas production rate was used for the Upper Green River Basin well type dehydrator emission calculation.

Depending upon the size of the dehydrator and the potential uncontrolled emission rate, emission controls on the dehydrator potential VOC emissions may be required. Pinedale assumed that all well site dehydrators were controlled at 95 percent. White River assumed dehydrator control for one of the alternatives. For purposes of this study, only wells in the Upper Green River Basin will have well-site dehydrators. Pinedale assumed 95 percent control; therefore the emission inventory also assumes 95 percent control on well-site dehydrators.

3.2.6. Oil and Condensate Production Rate and Decline Factor at Gas and Oil Wells

One of the key variables in determining emissions from storage tanks is the oil production rate for oil wells, the condensate production rate for gas wells, and the decline factor. Natural gas wells often have hydrocarbon liquids associated with the produced gas, and these liquids are termed condensate. Likewise, oil wells can have associated natural gas produced with the oil. For this study, the term “produced gas” is used for the natural gas produced from gas wells, the term “associated gas” is used for the natural gas associated (or produced) with oil wells, and the term “flash gas” is used for the vapor that is released from oil or condensate in storage tanks.

NDDEQ assumes an oil production rate of 250 barrels per day (bbl/d) for the first 30 days of production at oil wells. GNB assumed 10 bbl/d of condensate production for the first year, 3 bbl/d condensate production for the second and following years for gas wells. Jonah used a constant 25.3 bbl/d condensate production rate for gas wells. Pinedale used 30 bbl/d condensate for gas wells. San Juan Basin gas wells have relatively little to no condensate. Therefore, for purposes of this emissions inventory, the following oil and condensate production rates were assumed:

- Uinta/Piceance Gas Well ... 10 bbl condensate per day
- Upper Green River Gas Well ... 30 bbl condensate per day
- San Juan Gas Well ... 5 bbl condensate per day
- Williston Oil ... 150 bbl oil per day
- Denver Oil ... 125 bbl oil per day

NDDEQ uses an assumed decline factor of 0.6 (i.e., the average annual production rate in terms of bbl/d after the first 30 days will be 60 percent of the daily production during the first 30 days). GNB used a decline factor of 0.7 after the first year, Farmington RMP uses a 0.5 decline factor, Jonah used a factor of 0.7, and Pinedale used a factor of 0.335. For purposes of the

emission inventory, no decline factor was built in to the emission estimates because the project-specific production rate is not known, and thus a decline factor is meaningless. Thus, the emission inventories provide an upper bound estimate of emissions based on the production rate specified. If a project-specific production rate and/or decline factor is known, that data can be entered in to the spreadsheets to change the emission estimates.

3.2.7. Flash Gas to Oil Ratio for Gas and Oil Wells

The amount of vapor released in oil or condensate storage tanks is a function of the flash gas to oil ratio (Flash GOR). Flash GOR is also highly variable, even among different wells in the same basin. For purposes of the emissions inventory, the following Flash GORs were used for the gas and oil wells based on professional judgment:

- Uinta/Piceance Gas Well Flash GOR ...100 standard cubic foot of gas per barrel of condensate (scf/bbl)
- Upper Green River Gas Well Flash GOR ...98 scf/bbl of condensate
- San Juan Gas Well Flash GOR ... 75 scf/bbl of condensate
- Williston Oil Well Flash GOR ... 98 scf/bbl of oil
- Denver Oil Well Flash GOR ... 45 scf/bbl of oil

3.2.8. Well Gas-to-Oil Ratio for Oil Wells

Even though oil wells are developed to produce oil, they also have natural gas associated with them that comes from the geologic formation. This gas is termed “casing gas,” “associated gas,” or “produced gas.” The amount of associated gas is determined by the Well Gas-to-Oil Ratio (Well GOR).

In the Denver Basin, there is sufficient pipeline infrastructure that associated gas produced with Denver oil wells is normally either used on-site or piped to a sales line essentially as soon as the well is completed. Therefore, in the Denver Basin, it was assumed that there are no emissions from the associated gas.

On the other hand, in the Williston Basin, there is insufficient natural gas infrastructure available, and the associated gas can be vented, flared, used at the well site, sent to a sales line, or a combination. For purposes of this study, it was assumed that all of the associated gas from

Williston Basin oil wells was flared for a period of 3 months, after which it was assumed that the associated gas would be sent to a sales line. Accordingly, there are emissions from associated gas for a period of 3 months. The emissions result from combustion of the associated gas plus un-combusted associated gas (95 percent of the gas was assumed to be combusted with 5 percent passing through the flare un-combusted). The amount of associated gas flared was calculated from the assumed oil production rate of 150 bbl/day and a Well GOR of 1,100 scf/bbl of oil produced, or 165 Mscf of associated gas per day. The Well GOR value assumed for this study is based on professional judgment, and the Excel Workbook allows the user to enter a different value if known.

3.2.9. Produced Gas, Associated Gas, and Flash Gas Composition

As discussed previously, it was assumed that all five well types have oil/condensate storage tanks on site. The largest source of emissions from the storage tanks is the flash gas. The flash gas composition determines potential VOC, GHG and HAPs emissions. For this study, the flash gas composition was varied for each basin. The source of the flash gas compositions used in the study is as follows:

- Uinta/Piceance gas well ... liquids analysis of the condensate used in filed and approved Utah permit applications and the E&P Tanks emissions model
- Upper Green River gas well ... liquids analysis of the condensate used in the Wyoming Pinedale Tri-Annual Emissions Reporting default values and the E&P Tanks emissions model.
- San Juan gas well ... liquids analysis of the condensate used in filed and approved permit applications for Colorado and the E&P Tanks emissions model (same as the Denver Basin oil well)
- Williston oil well ... liquids analysis of oil used in filed and approved emission reporting efforts in North Dakota
- Denver oil well ... liquids analysis of the condensate used in filed and approved permit applications for Colorado and the E&P Tanks emissions model

For produced and associated gas composition, the CRV provided a detailed gas composition table, and that composition was used for all five basins. If project specific gas composition data are available, they can be entered into the Excel Workbook and the composition will flow through the calculations. The associated/produced gas composition data are used in the

emission calculations for fugitive emissions, pneumatic device emissions, venting, workover, and frac flowback emissions, plus emissions from flaring of associated gas in the Williston Basin.

3.2.10. Emissions from Produced Water

Some oil and gas wells have a meaningful amount of water associated with them. The produced water, which is stored in tanks, can contain VOCs that are emitted to the atmosphere. In order to calculate emissions from produced water, a produced water production rate needs to be known and then a known emission factor, or the USEPA TANKS emissions model could be used. For purposes of the emission inventories the TANKS model was not run because of the goal to have a stand-alone spreadsheet as discussed earlier with respect to working/breathing losses. Rather than running the TANKS model on a case by case basis, CDPHE published an emission factor (lb VOC per bbl of produced water) for produced water, which is 0.262 lb VOC per bbl for the Denver Basin and 0.178 lb VOC per bbl for some of the Colorado counties in the Piceance Basin. Due to the lack of other emission rates for produced water tanks, and to provide a reasonable upper bound estimate of emissions, each of the produced water tank emissions from each basin were calculated using the single CDPHE emission factor of 0.262 lb VOC per bbl.

To determine the amount of produced water, the PI/Dwights oil and gas production database was accessed through IHS Enerdeq (IHS, 2013) and an average produced water rate per well per year (rounded to the nearest thousand barrels) was calculated for all wells in the basin. The resulting produced water rates are as follows:

- Uinta/Piceance ...4,000 bbl water per well per year (bbl/well/yr)
- Upper Green River ...3,000 bbl/well/yr
- San Juan ... 800 bbl/well/yr
- Williston ... 36,000 bbl/well/yr
- Denver ... 11,000 bbl/well/yr

The amount of produced water is highly variable within a basin and depends on the specific well. For example, the range of produced water values for gas wells in the San Juan Basin is from zero to over 160,000 bbl/well/yr according to the PI/Dwights database.

3.2.11. Pneumatic Controllers

Pneumatic controllers are used at the well sites to open and close valves, operate pumps, and other purposes. Pneumatic controllers can emit natural gas containing VOCs as part of the operation. Pneumatic controllers are classified as high bleed, intermittent bleed, low bleed, and no bleed. High and low bleed controllers emit a small stream of gas continuously. Intermittent bleed controllers emit on an occasional basis, however the frequency of bleeding is generally not known. Accordingly, emission inventories usually assume either high, low, or no bleed controllers.

The number and type of pneumatic controllers varies depending on the needs of the well field and the operating company's standard practices. For purposes of the emission inventories it was assumed that all gas wells have pneumatic controllers (in addition to pneumatic pumps and other pneumatic devices) and the pneumatic controllers are all low bleed. This is consistent with the 40 CFR Subpart OOOO regulatory requirements discussed previously. No pneumatic controllers, pumps, or other pneumatic devices were assumed present for the oil wells in the Williston or Denver Basins.

3.2.12. Pumpjack Engines

Pumpjack engines are generally natural gas fueled and are relatively small, on the order of 65 to 95 horsepower. The Farmington RMP assumed a 95 hp engine; other EISs assume smaller engines and/or a 95 hp engine but use a load factor that results in an effective continuous horsepower that is much lower than the engine rating. For purposes of the emission inventory, it was assumed that all of the pumpjack engines would be 65 hp, with a load factor of 0.54, or an effective continuous hp of 35. These values were chosen based on professional judgment.

3.2.13. Fugitive Emissions (Equipment Leaks)

Well site equipment processes and transfers gases and light oils with meaningful amounts of VOCs. Therefore, fugitive emissions from equipment leaks must be accounted for and were included in the emission inventories. USEPA emission factors for leaks from valves, connectors (flanges), open ended lines, and pressure relief valves as published in 40 CFR 98 Subpart W were used. Although 40 CFR 98 Subpart W is for greenhouse gas (GHG) emissions, it includes emission factors for the amount of fugitive gas emissions at oil and gas well sites; and these

emission factors can be used to estimate not only GHG emissions but also HAPs and VOC emissions based on the gas composition. Thus the Subpart W emission factors were used. Typical counts for each type of leaking device at the well sites were input based on professional judgment. If other project specific information is available, equipment counts can be over-ridden in the spreadsheets. The emission factors assume no leak detection and repair (LDAR) program is implemented. If some sort of LDAR or inspection program is implemented, the emission factors should be adjusted accordingly. (LDAR may be required by 40 CFR 60 Subpart OOOO at some well sites on some of the equipment).

3.3. EMISSION INVENTORY RESULTS

Tables 3-1 through 3-5 show the emissions totals for each well type by activity. Except for sulfur dioxide, ethylbenzene, and nitrous oxide, the values in the Tables are rounded to one decimal place. Global warming potential (GWP) is rounded to a whole number.

Note that the tables report “total HAPs”; however, the total is based on only the five HAPs listed. There are trace amounts of other HAPs associated with oil and gas well development and production, but the amounts of those other HAPs are much, much smaller than the five key HAPs listed (the trace HAPs add less than a tenth of a percent to the total HAPs). There are three other HAPs emitted in meaningful quantities that are often associated with oil and gas production: formaldehyde, acetaldehyde, and acrolein. However, the main source of these HAPs are large natural gas compression engines at central gathering stations or field compression stations, which are not included in this study.

The Global Warming Potential (GWP) shown in the tables is calculated using a GWP of 1.0 for carbon dioxide, 21 for methane, and 310 for nitrous oxide. The individual greenhouse gas emissions are in terms of short tons for the individual greenhouse gas. The GWP is in terms of short tons of carbon dioxide equivalent (CO₂e).

As noted in Section 3.1, Construction emissions include emissions from interim and final reclamation of the well pad. Tables 3-1 through 3-5 are on the following pages.

Table 3-1
Emission Estimates by Activity for a Natural Gas Well in the Uinta/Piceance Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO _x	0.5	14.8	0.4	15.6
CO	0.3	3.2	0.4	3.8
VOC	0.04	0.7	2.6	3.4
SO ₂	0.0001	0.0002	0.0001	0.0004
PM ₁₀	2.0	4.9	0.04	6.9
PM _{2.5}	0.06	0.5	0.2	0.8
CO ₂	33.8	2,127.7	390.6	2,552.1
CH ₄	0.001	1.1	11.1	12.2
N ₂ O	0.0003	0.05	0.0008	0.05
GWP	34	2,165	624	2,825
Benzene	0.00	1.4	0.04	1.4
Toluene	0.00	1.0	0.02	1.0
Ethylbenzene	0.00	0.00	0.00003	0.00003
Xylene	0.00	0.6	0.01	0.6
n-Hexane	0.00	7.3	0.19	7.5
Total HAPs	0.00	10.2	0.25	10.4

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

Table 3-2
Emission Estimates by Activity for a Natural Gas Well in the Upper Green River Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO _x	0.5	13.2	0.9	14.6
CO	0.3	2.9	0.8	3.9
VOC	0.04	0.7	4.4	5.2
SO ₂	0.0001	0.0002	0.0001	0.0004
PM ₁₀	1.9	4.7	0.08	6.7
PM _{2.5}	0.06	0.4	0.3	0.8
CO ₂	33.8	1,900.3	948.0	2,882.1
CH ₄	0.001	1.1	13.0	14.1
N ₂ O	0.0003	0.05	0.002	0.05
GWP	34	1,937	1,222	3,194
Benzene	0.00	1.4	0.1	1.5
Toluene	0.00	1.0	0.2	1.2
Ethylbenzene	0.00	0.00	0.01	0.01
Xylene	0.00	0.6	0.2	0.7
n-Hexane	0.00	7.3	0.2	7.5
Total HAPs	0.00	10.2	0.7	10.9

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

Table 3-3
Emission Estimates by Activity for a Natural Gas Well in the San Juan Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO _x	0.5	4.0	1.1	5.6
CO	0.3	1.1	1.8	3.1
VOC	0.04	0.3	5.0	5.3
SO ₂	0.0001	0.0002	0.0008	0.001
PM ₁₀	2.1	4.7	0.08	6.8
PM _{2.5}	0.06	0.1	0.3	0.5
CO ₂	33.8	561.6	56.4	651.9
CH ₄	0.001	1.1	5.0	6.1
N ₂ O	0.0003	0.04	0.0004	0.04
GWP	34	595	161	791
Benzene	0.00	1.4	0.03	1.4
Toluene	0.00	1.0	0.02	1.0
Ethylbenzene	0.00	0.00	0.0008	0.0008
Xylene	0.00	0.6	0.01	0.6
n-Hexane	0.00	7.3	0.2	7.5
Total HAPs	0.00	10.2	0.3	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

Table 3-4
Emission Estimates by Activity for an Oil Well in the Williston Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO _x	0.5	13.2	1.8	15.6
CO	0.3	2.9	4.9	8.0
VOC	0.04	0.7	16.8	17.6
SO ₂	0.0001	0.0002	0.0008	0.001
PM ₁₀	2.0	4.8	0.1	6.9
PM _{2.5}	0.06	0.4	0.3	0.8
CO ₂	33.8	1,900.3	1,222.3	3,156.4
CH ₄	0.001	1.1	15.4	16.6
N ₂ O	0.0003	0.05	0.5	0.6
GWP	34	1,922	1,700	3,682
Benzene	0.00	1.4	0.2	1.5
Toluene	0.00	1.0	0.02	1.0
Ethylbenzene	0.00	0.00	0.0008	0.0008
Xylene	0.00	0.6	0.01	0.6
n-Hexane	0.00	7.3	0.6	7.9
Total HAPs	0.00	10.2	0.9	11.0

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

Table 3-5
Emission Estimates by Activity for an Oil Well in the Denver Basin

Pollutant	Construction (tpy)	Development (tpy)	Operation (tpy)	Total (tpy)
NO _x	0.5	4.5	1.3	6.3
CO	0.3	1.2	2.0	3.4
VOC	0.04	0.3	6.4	6.7
SO ₂	0.0001	0.0002	0.008	0.001
PM ₁₀	2.0	4.5	0.1	6.6
PM _{2.5}	0.06	0.2	0.3	0.5
CO ₂	33.8	623.7	391.5	1,050.0
CH ₄	0.001	1.1	0.7	1.8
N ₂ O	0.0003	0.04	0.001	0.04
GWP	34	657	406	1,099
Benzene	0.00	1.4	0.06	1.4
Toluene	0.00	1.0	0.01	1.0
Ethylbenzene	0.00	0.00	0.0006	0.0006
Xylene	0.00	0.6	0.004	0.6
n-Hexane	0.00	7.3	0.2	7.5
Total HAPs	0.00	10.2	0.4	10.5

Note: Sums may not precisely total due to round off differences. A value of 0.00 indicates that pollutant is not emitted or emitted in de minimis amounts. If there is a non-zero value, at least one significant figure is reported.

4 CONCLUSION

Five different emission estimate inventories were developed to represent typical oil and gas well emissions in the western US. California, Texas, Oklahoma, Kansas, and Alaska were not included in the study due to relatively little BLM land with oil and gas development in those states, those states have their own program for estimating emissions, and/or the unique environment of Alaska. The five well types chosen for analysis were natural gas wells from the Uinta/Piceance, Upper Green River, and San Juan Basins and oil wells from the Williston and Denver Basins. These Basins are responsible for a large portion of the oil and gas produced in the western United States. Characteristics of these basins as they affect emission estimates were described so that a user of the emission inventory can select a representative well type for development in other basins or sub-basins in the western US. The emission inventories focus on projects where there are a small number of wells, generally termed wildcat or delineation wells.

The emission estimates are suitable for use to estimate emissions from a small number of wells, and should not normally be extrapolated to large well fields with multiple wells. The inventories are based on generally accepted emission estimating techniques published by the USEPA. However, these techniques require a large number of case-specific parameters in order to estimate emissions. Typical parameters for each of the Basins studied were used to calculate the emissions, but there is a wide range of possible values, and project-specific information should be used whenever available.

Electronic and hard copy emission inventories were created. The electronic version of the emission spreadsheets can be modified by the user by overriding key parameters with project-specific data if available. Emissions were calculated for the criteria pollutants associated with oil and gas development, greenhouse gases (including calculation of global warming potential), and the five hazardous air pollutants that are emitted in meaningful amounts and traditionally associated with emissions from a single oil or gas well: hexane, benzene, toluene, ethylbenzene, and xylene.

The emission inventories can be easily modified to account for project-specific information that may be available. If no project-specific information is available, the emission inventories provide typical values for the selected basins and the inventories can be extrapolated to other basins in

the western US as needed. If project-specific variables are entered into the Excel Workbook, the variables should be entered in the “Constants and References” tab and the entered variables will be automatically populated into the emission estimating equations in the Workbook. If a range of emission estimates are needed instead of a single value, a range of emission estimates can be created by entering a range of parameters in the Excel Workbook.

5 LIMITATIONS

This work was performed in a manner consistent with that level of care and skill ordinarily exercised by other members of Kleinfelder's profession practicing in the same locality, under similar conditions and at the date the services are provided. Our conclusions, opinions, and recommendations are based on a limited number of observations and data. It is possible that conditions could vary between or beyond the data evaluated. Kleinfelder makes no other representation, guarantee, or warranty, express or implied, regarding the services, communication (oral or written), report, opinion, or instrument of service provided. This report may be used only by the client and only for the purposes stated for this specific engagement within a reasonable time from its issuance.

The work performed was based on the scope of work requested by the client. Kleinfelder offers various levels of investigative and engineering services to suit the varying needs of different clients. It should be recognized that definition and evaluation of environmental conditions are a difficult and inexact science. Judgments leading to conclusions and recommendations are generally made with incomplete knowledge of the facility and conditions present due to the limitations of data. Although risk can never be eliminated, more detailed and extensive studies yield more information, which may help understand and manage the level of risk. Since detailed study and analysis involves greater expense, our clients participate in determining levels of service that provide adequate information for their purposes at acceptable levels of risk. More extensive studies should be performed to reduce uncertainties. Acceptance of this report will indicate that the client has reviewed the document and determined that it does not need or want a greater level of service than provided.

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APPENDIX A
ELECTRONIC VERSION OF EMISSIONS INVENTORIES

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Location Selection:

Geography: **Well Type:**
 Uinta/Piceance Basin Natural Gas

- Choose geography/basin, and well type will automatically fill
- < Choose Uinta/Piceance Basin for deep gas wells with little condensate
- < Choose Upper Green River Basin for deep gas wells with dehydrators and higher condensate
- < Choose San Juan Basin for shallow gas wells with little to no condensate
- < Choose Williston Basin for deep oil wells with high gas
- < Choose Denver Basin for shallow oil wells with low gas

If the user wants to change any specifications, do so within the "Constants and References" tab, as all other tabs connect to it.

Pollutant:	Total Emissions (Tons per Year)								
	NO _x	CO	VOC	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O
Construction Phase:	0.47	0.29	0.04	0.0001	1.99	0.06	33.84	0.001	0.0003
Development Phase:	14.77	3.15	0.74	0.0002	4.89	0.49	2127.69	1.12	0.0516
Operation Phase:	0.39	0.36	2.62	0.0001	0.04	0.23	390.55	11.09	0.0008
Total:	15.63	3.80	3.40	0.0004	6.93	0.78	2552.08	12.21	0.0526

Pollutant:	Total Emissions (Tons per Year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	HAPs
Construction Phase:	0.00	0.00	0.00	0.00	0.00	0.00
Development Phase:	1.36	0.95	0.0000	0.55	7.31	10.18
Operation Phase:	0.03	0.01	0.00003	0.009	0.16	0.21
Total:	1.39	0.97	0.00003	0.56	7.46	10.39

CO ₂ equivalent (Global Warming Potential)	
Total TPY:	2824.87
CO ₂ equivalent conversions:	
CO ₂	1.00
CH ₄	21.00
N ₂ O	310.00

H ₂ S Emissions	
Total TPY:	0.00

* If H₂S in gas, input value in "Gas Stream Molar Ratios" tab, and potential emissions will calculate here. Current assumption is no H₂S in gas stream.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Road Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	4	Days/Location	(Typical Value)
	48.0	Dozer Hours/Location	(Typical Value)
	48.0	Backhoe Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅ (AP-42 Table 11.9-1, 7/98)		
PM _{2.5} Multiplier:	0.105 * TSP (AP-42 Table 11.9-1, 7/98)		

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98 & 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0473	1.97	0.0473	0.0946
PM₁₅	0.50	0.0120	0.50	0.0120	0.0241
PM₁₀	0.38	0.0090	0.38	0.0090	0.0181
PM_{2.5}	0.21	0.0050	0.05	0.0013	0.0062

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase
Road Grader Particulate Matter

Assumptions:

Grading Length:	6.00	miles	(Typical Value)
Construction Schedule:	3	Days/Location	(Typical Value)
	12	Hours/Day	(Typical Value)
	36	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	
Average Grader Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 16.12 lbs TSP/Location

Emissions = 7.71 lbs PM₁₅/Location

Grader Construction Emissions			
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	16.12	0.45	8.06E-03
PM₁₅	7.71	0.21	3.86E-03
PM₁₀	4.63	0.13	2.31E-03
PM_{2.5}	0.50	0.01	2.50E-04

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Well Pad Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7	Days/Location		(Typical Value)
	10	Hours/Day		(Typical Value)
	70	Hours/Location	(Dozer)	(Typical Value)
	70	Hours/Location	(Back Hoe)	(Typical Value)
Watering Control Efficiency:	50	Percent (%)		(Typical Value)
Soil Moisture Content:	7.9	Percent (%)		AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)		AP-42 Table 11.9-3, 7/98

PM₁₀ Multiplier: 0.75 * PM₁₅ (AP-42 Table 11.9-1, 7/98)

PM_{2.5} Multiplier: 0.105 * TSP (AP-42 Table 11.9-1, 7/98)

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

Emissions (TSP lbs/hr) = $5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs/hr) = $1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Well Pad Grader Particulate Matter

Assumptions:

Construction Schedule:	4.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	40	Hours/Location	(Typical Value)
Watering Control Efficiency	50	Percent (%)	(Typical Value)
Average Grader Speed	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
Distance Graded	2.84	Miles/Location	(Typical Value)
PM ₁₀ Multiplier	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 7.63 lbs TSP/well pad

Emissions = 3.65 lbs PM₁₅/well pad

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	7.63	0.19	0.0038
PM₁₅	3.65	0.09	0.0018
PM₁₀	2.19	0.05	0.0011
PM_{2.5}	0.24	0.01	0.0001

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Pipeline Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase
Pipeline Grader Particulate Matter

Assumptions:

Distance Graded:	12.50	Miles/Location	(Typical Value)
Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Mean Vehicle Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs) = $0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs) = $0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions = 33.58 lbs TSP/well

Emissions = 16.07 lbs PM₁₅/well

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	33.58	0.48	0.0168
PM₁₅	16.07	0.23	0.0080
PM₁₀	9.64	0.14	0.0048
PM_{2.5}	1.04	0.01	0.0005

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Heavy Diesel Truck Trips:

Road Construction:	7	Trips			
Well Pad Construction:	8	Trips	Total Trips:	21	Trips
Pipeline Construction:	6	Trips			

Light Duty Pickup Truck Trips:

Road Construction:	16	Trips			
Well Pad Construction:	28	Trips	Total Trips:	100	Trips
Pipeline Construction:	56	Trips			

* All assumptions above are based on typical industry values

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a	Emissions	E. Factor ^b	Emissions	Emissions
	(lb/mile)	(Tons/Location)	(lb/mile)	(Tons/Location)	(Tons/Location)
NOx	7.44E-02	3.12E-02	7.39E-03	1.48E-02	4.60E-02
CO	1.98E-02	8.32E-03	7.26E-02	1.45E-01	1.54E-01
VOC	3.16E-03	1.33E-03	3.54E-03	7.08E-03	8.41E-03
SO2	4.57E-05	1.92E-05	2.83E-05	5.66E-05	7.58E-05
PM10	4.22E-03	1.77E-03	1.94E-04	3.88E-04	2.16E-03
PM2.5	4.09E-03	1.72E-03	1.79E-04	3.58E-04	2.08E-03
CO2	1.88	0.79	1.13	2.25	3.04
CH4	7.61E-05	3.19E-05	4.56E-05	9.13E-05	1.23E-04
N2O	1.52E-05	6.39E-06	9.13E-06	1.83E-05	2.46E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Construction Heavy Equipment Tailpipe Emissions

Assumptions:

Fuel and Engine:

Brake Specific Fuel Consumption, Avg. (BSFC) 8250 btu/hp-hr (Typical Value)
Diesel Higher Heating Value (HHV) 0.138 mmBtu/Gallon (Typical Value)

Trackhoe:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 100 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Tractors/Loaders/Backhoes)

Dozer:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 140 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Crawler Tractor/Dozers)

Grader:

Working Hours 130 Total Hours (Typical Value)
Rated Horsepower 250 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Graders)

Total Horsepower Hours: 45795.8 Hp-hrs (Sum of all horsepower above)
Total Fuel Usage: 2737.79 Gallons Diesel Fuel

Equations:

Total Fuel Usage: ((btu-hp-hr * hp-hrs) / Mmbtu-gal) / 1,000,000
Emissions (tons/year/pad) = $\frac{\text{Emission Factor (g/mile)} * \text{Trip Distance (miles)} * \text{Load Factor}}{453.6 \text{ (g/lb)} * 2000 \text{ (lb/tons)}}$

Heavy Const. Vehicles	Backhoe			Dozer			Grader		
	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
NOx	8.38	1.09E+00	1.02E-01	8.38	1.53E+00	1.43E-01	8.38	2.72E+00	1.77E-01
CO	2.7	3.51E-01	3.30E-02	2.7	4.92E-01	4.62E-02	2.7	8.78E-01	5.71E-02
VOC ^b	0.68	8.84E-02	8.31E-03	0.68	1.24E-01	1.16E-02	0.68	2.21E-01	1.44E-02
PM₁₀	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03
PM_{2.5}	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03

Heavy Const. Vehicles	Total
	Emissions ^c (tons/yr)
NOx	0.42
CO	0.14
VOC	0.03
PM₁₀	0.02
PM_{2.5}	0.02

Greenhouse Gas Emissions:

	Diesel EF kg/mmbtu	Emissions lbs	Emissions Tons
CO ₂	73.96	61604.19	30.80
CH ₄	0.003	2.50	0.0012
N ₂ O	0.0006	0.50	0.0002

a From Table A-4 of Exhaust and Crankcase Emission Factors for NONROAD Engine Modeling - Compression Ignition, EPA-420-R-10-018, July 2010.

b Emission Factor represents total Hydrocarbon Emissions

c Converted from emission factor for Distillate Fuel Oil #2 (diesel) as listed in Table C-1 to Subpart C of Part 98 - Default Emission Factors and High Heat Values for Various Types of Fuel.

Listed Factor:

73.96 kg CO₂/mmBtu
393 hp-hr = mmBtu
188.2 g CO₂/hp-hr

Kleinfelder, Inc. Wellsite Emissions		Base Location: Uinta/Piceance Basin Well Type: Natural Gas													
Construction Phase Wind Erosion Fugitive Dust															
Assumptions:															
Threshold Friction Velocity (U _t)	1.02	m/s (2.28 mph) for well pads (AP-42 Table 13.2.5-2 Overburden - Western Surface Coal Mine)													
	1.33	m/s (2.97 mph) for roads (AP-42 Table 13.2.5-2 Roadbed material)													
Initial Disturbance Area															
Total Access Road/ROW Area Per Location:	976,800	Square Meters	(Typical Value)												
Total Well Pad Area Disturbed Per Location:	50,000	Square Meters	(Typical Value)												
Total Area Disturbed Per Location:	1,026,800	Square Meters	(Typical Value)												
Exposed Surface Type	Flat														
Meteorological Data	2002 Grand Junction (obtained from NCDC website)														
Fastest Mile Wind Speed:	45	miles/hour	(Typical Value)												
Fastest Mile Wind Speed (U ₁₀ ⁺)	20.12	meters/sec (45 mph) reported as fastest 2-minute wind speed for Grand Junction (2002)													
Number soil of disturbances	1.00	for well pads (Assumption, disturbance at construction and reclamation) constant for dirt roads													
Equations (AP-42 13.2.5.2 Industrial Wind Erosion)															
Friction Velocity U* = 0.053 U ₁₀ ⁺															
Erosion Potential P (g/m ² /period) = 58*(U*-U _t *) ² + 25*(U*-U _t *) for U*>U _t *, P = 0 for U*< U _t *															
Emissions (tons/year) = Erosion Potential(g/m ² /period)*Disturbed Area(m ²)*Disturbances/year*(k)/(453.6 g/lb)/2000 lbs/ton/Develop Period															
<table><tr><th colspan="3">Particle Size Multiplier (k)</th></tr><tr><th>30 μm</th><th><10 μm</th><th><2.5 μm</th></tr><tr><td>1.0</td><td>0.5</td><td>0.075</td></tr></table>				Particle Size Multiplier (k)			30 μm	<10 μm	<2.5 μm	1.0	0.5	0.075			
Particle Size Multiplier (k)															
30 μm	<10 μm	<2.5 μm													
1.0	0.5	0.075													
<table><tr><th>Maxium U₁₀⁺ Wind Speed (m/s)</th><th>Maximum U* Friction Velocity m/s</th><th>Well U_t* Threshold Velocity^a m/s</th><th>Well Pad Erosion Potential g/m²</th><th>Road U_t* Threshold Velocity^a m/s</th><th>Road Erosion Potential g/m²</th></tr><tr><td>20.12</td><td>1.07</td><td>1.02</td><td>1.28</td><td>1.33</td><td>0.00</td></tr></table>				Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²	20.12	1.07	1.02	1.28	1.33	0.00
Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²										
20.12	1.07	1.02	1.28	1.33	0.00										
Wind Erosion Emissions															
<table><tr><th>Particulate Species</th><th>Well Pad (tons/year)</th><th>Roads/Pipelines (tons/year)</th></tr><tr><td>TSP</td><td>7.05E-02</td><td>0.00E+00</td></tr><tr><td>PM₁₀</td><td>3.52E-02</td><td>0.00E+00</td></tr><tr><td>PM_{2.5}</td><td>5.28E-03</td><td>0.00E+00</td></tr></table>				Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)	TSP	7.05E-02	0.00E+00	PM ₁₀	3.52E-02	0.00E+00	PM _{2.5}	5.28E-03	0.00E+00
Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)													
TSP	7.05E-02	0.00E+00													
PM ₁₀	3.52E-02	0.00E+00													
PM _{2.5}	5.28E-03	0.00E+00													

Kleinfelder, Inc.				Base Location: Uinta/Piceance Basin					
Wellsite Emissions				Well Type: Natural Gas					
Construction, Development, and Production Phase									
Construction, Development, and Operations Traffic Fugitive Dust Emissions									
Assumptions:									
				Round Trip Miles	40				
				Round Trip (Paved) Miles	16				
				Round Trip (Un-Paved) Miles	24				
				Precipitation Days (P)	45				
Unpaved Calculation AP-42, Chapter 13.2.2				E (PM ₁₀) / VMT = 1.5 * (S/12) ^{0.9} * (W/3) ^{0.45} * (365-p)/365)					
November 2006				E (PM _{2.5}) / VMT = 0.15 * (S/12) ^{0.9} + (W/3) ^{0.45} * (365-p)/365)					
				Silt Content (S)	8.5			AP 42 13.2.2-1 Mean Silt Content Construction Sites	
Paved Calculation AP-42, Chapter 13.2.1				E (PM ₁₀) / VMT = 0.0022 * (d _L) ^{0.91} * (W) ^{1.02} * (1-(P/(365*4)))					
January 2011				E (PM _{2.5}) / VMT = 0.00054 * (d _L) ^{0.91} * (W) ^{1.02} * (1-(P/(365*4)))					
				Silt Loading (d _L)	0.6			AP-42 Table 13.2.1-2 baseline low volume roads	
Unpaved Calculations:									
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	3.09	1558.9	0.8	0.3	155.9	0.1
	Light Duty Pickup Trucks	5,000	100	0.89	2131.8	1.1	0.1	213.2	0.1
	Total:				3690.67	1.85		369.07	0.18
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	0.0576	19.4	0.0097	0.014	4.8	0.0024
	Light Duty Pickup Trucks	5,000	100	0.0034	5.5	0.0027	0.001	1.3	0.0007
	Total:				24.8	0.0		6.1	0.0
Unpaved Calculations:									
Development Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	84	0.89	1790.7	0.9	0.1	179.1	0.1
	Light Duty Haul Trucks	7,500	11	1.07	281.4	0.1	0.1	28.1	0.0
	Heavy Duty Haul Trucks	80,000	67	3.09	4973.6	2.5	0.3	497.4	0.2
	Water Trucks	70,000	24	2.91	1677.7	0.8	0.3	167.8	0.1
	Total:				8723.41	4.36		872.34	0.44
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips						
	Light Duty Pickup Trucks:	5000	84	0.00	4.6	0.0	0.0	1.1	0.0006
	Light Duty Haul Trucks	7500	11	0.01	0.9	0.0	0.0	0.2	0.0001
	Heavy Duty Haul Trucks	80000	67	0.06	61.8	0.0	0.0	15.2	0.0076
	Water Trucks	70000	24	0.05	19.3	0.0	0.0	4.7	0.0024
	Total:				86.6	0.0		21.2	0.0
Unpaved Calculations:									
Production Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	50	0.89	1065.89	0.53	0.0888	106.59	0.0533
	Light Duty Haul Trucks	7,500	0	1.07	0.00	0.00	0.1066	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	3.09	148.47	0.07	0.3093	14.85	0.0074
	Water Trucks	70,000	40	2.91	2796.14	1.40	0.2913	279.61	0.1398
	Total:				4010.50	2.01		401.05	0.20
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	50	0.00	2.73	0.0014	0.0008	0.67	0.0003
	Light Duty Haul Trucks	7,500	0	0.01	0.00	0.0000	0.0013	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	0.06	1.84	0.0009	0.0141	0.45	0.0002
	Water Trucks	70,000	40	0.05	32.18	0.0161	0.0123	7.90	0.0039
	Total:				36.75	0.02		9.02	0.00
Annual Total					Unpaved Roads			Unpaved Roads	
					PM ₁₀		PM _{2.5}		PM _{2.5}
					(tons)		(tons)		(tons)
					8.21		0.8		0.8
					Paved Roads			Paved Roads	
					PM ₁₀		PM _{2.5}		PM _{2.5}
					0.1		0.0		0.0
					Total:			8.3	
								0.8	

Kleinfelder, Inc. Wellsite Emissions					Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																			
Development Phase Conductor Pipe Set Emissions																																								
Assumptions:																																								
<table><tr><th>Parameter</th><th>Value</th></tr><tr><td>Days of Operation</td><td>2</td></tr><tr><td>Hours of Operation</td><td>24</td></tr><tr><td>Diesel Fuel Sulfur Content</td><td>0.000015</td></tr></table>					Parameter	Value	Days of Operation	2	Hours of Operation	24	Diesel Fuel Sulfur Content	0.000015	<table><tr><th>Parameter</th><th>Value</th><th>Units</th></tr><tr><td>BSFC (Avg.)</td><td>8250</td><td>btu/hp-hr (Typical Value)</td></tr><tr><td>Diesel HHV</td><td>0.138</td><td>mmbtu/gal (Typical Value)</td></tr></table>					Parameter	Value	Units	BSFC (Avg.)	8250	btu/hp-hr (Typical Value)	Diesel HHV	0.138	mmbtu/gal (Typical Value)														
Parameter	Value																																							
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Workovers:					Greenhouse Gases:																																			
<table><tr><th>Engine</th><th>HP</th><th>Load Factor</th><th>Run time (hrs)</th><th>Total Hp-hrs</th></tr><tr><td>Rig Engine</td><td>350</td><td>0.42</td><td>24</td><td>3528</td></tr><tr><td>Rig Generator</td><td>50</td><td>0.42</td><td>24</td><td>504</td></tr></table>					Engine	HP	Load Factor	Run time (hrs)	Total Hp-hrs	Rig Engine	350	0.42	24	3528	Rig Generator	50	0.42	24	504	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>5423.82</td><td>2.71</td></tr><tr><td>CH4</td><td>0.003</td><td>0.22</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.04</td><td>0.00</td></tr></table>						Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	5423.82	2.71	CH4	0.003	0.22	0.00	N2O	0.0006	0.04	0.00
Engine	HP	Load Factor	Run time (hrs)	Total Hp-hrs																																				
Rig Engine	350	0.42	24	3528																																				
Rig Generator	50	0.42	24	504																																				
	Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location																																					
CO2	73.96	5423.82	2.71																																					
CH4	0.003	0.22	0.00																																					
N2O	0.0006	0.04	0.00																																					
Total Horsepower: 400					Greenhouse gas emission factors from Subpart C, Table C-1 and C-2																																			
Total: 4,032 Hp-hrs					Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu																																			
Fuel Usage: 241 Gallons of Diesel																																								
Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)																														
Rig Engine	3528	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	0.0008	0.0003	0.0002																														
Rig Generator	504	5.0000	6.9000	0.8000	0.7760	1.27E-05	1.8000	0.0008	0.0003	0.0002																														
Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																														
Rig Engine		0.00328	0.01686	0.00051	0.00050	0.00000	0.00064	0.00001	0.00000	0.00000																														
Rig Generator		0.00278	0.00383	0.00044	0.00043	0.00000	0.00100	0.00000	0.00000	0.00000																														
Total:		0.00605	0.02069	0.00096	0.00093	0.00000	0.00164	0.00001	0.00000	0.00000																														
Calculations:																																								
ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																								
* Rig engine emission rates are based on a Tier II engine and rig generator emission rates are based on a Tier 0 engine.																																								
* All days, hours, and HP values above are based on typical industry values																																								

$$\text{ton/year: } (\text{Total hp-hr} * \text{g-hp-hr}) * \text{lb-gram} / \text{lb-ton}$$

Kleinfelder, Inc. Wellsite Emissions			Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																																																																																																																														
Development Phase																																																																																																																																																																	
Hydraulic Fracturing Flowback Emissions																																																																																																																																																																	
Assumptions:																																																																																																																																																																	
Estimated Frac flowback Rate:		10,000	Scf/hr																																																																																																																																																														
Combustion Efficiency:		95.00	Percent (%)																																																																																																																																																														
Event Duration:		100.00	Hours																																																																																																																																																														
		379.49	Scf/lb-mol	- Typical/Constant Conversion Value																																																																																																																																																													
* Venting duration based on research and industry knowledge; please see report for additional information.																																																																																																																																																																	
* Venting control based on Subpart OOOO requirements of 95% minimum control.																																																																																																																																																																	
Control efficiency can be deleted if applicable.																																																																																																																																																																	
Equations:																																																																																																																																																																	
Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr																																																																																																																																																																	
** Multiply above equation by 0.02 if including 98% control efficiency																																																																																																																																																																	
Un-combusted Componet Emissions:																																																																																																																																																																	
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^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.																																																																																																																																																																	
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	Molar Ratio (%)	Scf/hr	lbs/hr	Tons/Year																																																																																																																																																													
C1	88.97	8452.34	980.23	49.01																																																																																																																																																													
C2	5.79	550.24	63.81	3.19																																																																																																																																																													
C3	1.37	129.68	15.04	0.75																																																																																																																																																													
C4	0.63	59.95	6.95	0.35																																																																																																																																																													
C5+	0.76	72.58	8.42	0.42																																																																																																																																																													
		CO ₂ Total Emissions:	53.72	Tons/Event																																																																																																																																																													
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	CO	0.37	3.80	0.19	AP-42 CH13.5-1																																																																																																																																																												
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	SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight																																																																																																																																																												

Kleinfelder, Inc. Wellsite Emissions				Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																		
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Development Phase

Well Venting During Workover Events

Assumptions:

Significant gas venting only occurs on natural gas wells.

Estimated Venting Rate: 5,000 Scf/Event (Typical Value)
Combustion Efficiency: 0.00 Percent (%)
Event Quantity: 1.00 Event - Assumed one event
379.49 Scf/lb-mol - Typical/Constant Conversion Value
* Vented quantity based on research and industry knowledge; please see report for additional information.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf-lb-mol)
** Multiply above equation by 0.02 if including 98% control efficiency

Component	Mole %	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Event
Methane	88.9720	16.0	4448.60	188.07	0.0940
Ethane	5.7920	30.1	289.60	22.95	0.0115
Propane	1.3650	44.1	68.25	7.93	0.0040
i-Butane	0.3700	58.1	18.50	2.83	0.0014
n-Butane	0.2610	58.1	13.05	2.00	0.0010
i-Pentane	0.1550	72.2	7.75	1.47	0.0007
n-Pentane	0.1020	72.2	5.10	0.97	0.0005
Other Pentanes	0.0000	70.1	0.00	0.00	0.0000
Hexanes	0.1460	86.2	7.30	1.66	0.0008
Heptanes	0.0930	100.2	4.65	1.23	0.0006
Octanes	0.0440	114.2	2.20	0.66	0.0003
Nonanes	0.0160	128.3	0.80	0.27	0.0001
Decanes +	0.0050	142.3	0.25	0.09	0.0000
Benzene	0.0270	78.1	1.35	0.28	0.0001
Toluene	0.0190	92.1	0.95	0.23	0.0001
Ethylbenzene	0.0000	106.2	0.00	0.00	0.0000
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.0000
Xylenes	0.0110	106.2	0.55	0.15	0.0001
n-Hexane	0.1460	86.2	7.30	1.66	0.0008
Nitrogen	0.0940	28.0	4.70	0.35	0.0002
Carbon Dioxide	2.5280	44.0	126.40	14.66	0.0073
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.0000

VOC Subtotal	2.7600	1492.8	138.00	21.44	0.0107
HAPS Subtotal	0.2030	546.9	10.15	2.32	0.0012
Total	100.1460	1645.0	5007.30	247.46	0.1237

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP. was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year	
C1	88.97	0.00	0.00	0.00	
C2	5.79	0.00	0.00	0.00	
C3	1.37	0.00	0.00	0.00	
C4	0.63	0.00	0.00	0.00	
C5+	0.76	0.00	0.00	0.00	
		CO₂ Total Emissions:	0.00	Tons/Event	
		N₂O Emissions:	5.67E-07	Tons/Event	

Flare Combustion Emissions:

Fuel Heating Value:	1028.00	btu/scf		
	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NOx	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.000	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin

Well Type: Natural Gas

Development Phase

Wellsite Development Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks:	84	Trips/Location			
Light Duty Haul Trucks	11	Trips/Location	Total Trips:	95	Trips

Heavy Duty Haul Trucks	67	Trips/Location			
Water Trucks	24	Trips/Location	Total Trips:	91	Trips

* Miles and number of trips based on research and industry knowledge;
please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NOx	7.44E-02	1.35E-01	1.98E-02	1.41E-01	2.77E-01
CO	1.98E-02	3.60E-02	3.16E-03	3.76E-02	7.37E-02
VOC	3.16E-03	5.75E-03	4.57E-05	6.00E-03	1.18E-02
SO2	4.57E-05	8.32E-05	4.22E-03	8.68E-05	1.70E-04
PM10	4.22E-03	7.68E-03	4.09E-03	8.02E-03	1.57E-02
PM2.5	4.09E-03	7.44E-03	1.88E+00	7.77E-03	1.52E-02
CO2	1.88E+00	3.41E+00	7.61E-05	3.56E+00	6.98E+00
CH4	7.61E-05	1.38E-04	1.52E-05	1.45E-04	2.83E-04
N2O	1.52E-05	2.77E-05	0.00E+00	2.89E-05	5.66E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite for calendar year 2012.

c Assumes maximum development scenario

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Development Phase
Wellhead Gas Combustion

**Wellhead gas combustion only for Williston Basin wells, due to the regularity of of pit flares combusting all gas coming from the wellhead. If gas being captured, change scf/hr value or hours of event value.

Assumptions:

Estimated Gas Flow Rate: 0 Scf/hr
Combustion Efficiency: 0.00 Percent (%)
Event Duration: 0.00 Hours - Estimated 3 months before sales line
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* It is assumed that all produced natural gas is sent to a sales line after the well is completed.

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr
** Multiply above equation by 0.05 if including 95% control efficiency

Combusted Component Emissions:

Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	0.00	0.00	0.00
Ethane	5.7920	30.1	0.00	0.00	0.00
Propane	1.3650	44.1	0.00	0.00	0.00
i-Butane	0.3700	58.1	0.00	0.00	0.00
n-Butane	0.2610	58.1	0.00	0.00	0.00
i-Pentane	0.1550	72.2	0.00	0.00	0.00
n-Pentane	0.1020	72.2	0.00	0.00	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.00	0.00	0.00
Heptanes	0.0930	100.2	0.00	0.00	0.00
Octanes	0.0440	114.2	0.00	0.00	0.00
Nonanes	0.0160	128.3	0.00	0.00	0.00
Decanes +	0.0050	142.3	0.00	0.00	0.00
Benzene	0.0270	78.1	0.00	0.00	0.00
Toluene	0.0190	92.1	0.00	0.00	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.00	0.00	0.00
n-Hexane	0.1460	86.2	0.00	0.00	0.00
Nitrogen	0.0940	28.0	0.00	0.00	0.00
Carbon Dioxide	2.5280	44.0	0.00	0.00	0.00
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00
VOC Subtotal	2.7600	1492.8	0.00	0.00	0.00
HAPS Subtotal	0.2030	546.9	0.00	0.00	0.00
Total	100.1460	1645.0	0.00	0.00	0.00

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	0.00	0.00	0.00
C2	5.79	0.00	0.00	0.00
C3	1.37	0.00	0.00	0.00
C4	0.63	0.00	0.00	0.00
C5+	0.76	0.00	0.00	0.00

CO₂ Total Emissions: 0.00 Tons/Year
N₂O Emissions: 0.00E+00 Tons/Year

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NO _x	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.**Wellsite Emissions****Base Location:** Uinta/Piceance Basin**Well Type:** Natural Gas**Production Phase****Production Equipment Fugitive Component Emissions****Assumptions:**Components Counts:

Component *	Fugitive Components				
	Valves	Connectors	OE Lines	PR Valves	
Count	59	193	8	3	0
Emissions Factor (scf/hr) ^b	0.121	0.017	0.031	0.193	0.000

* Fugitive component counts for natural gas wells from Subpart W, Table W-1B

* Fugitive component counts for oil wells from Subpart W, Table W-1C

Annual Equipment Run Time:

8760

Hours/Year

379.49 Scf/lb-mol

Component	Mole % ^a	Mole Weight lb/lb-mol	Emissions Scf/Year ^b	Emissions lbs/Year	Emissions Tons/Year
Methane	88.9720	16.0	87,658.5	3,705.8	1.85
Ethane	5.7920	30.1	5,706.5	452.2	0.23
Propane	1.3650	44.1	1,344.8	156.3	0.08
i-Butane	0.3700	58.1	364.5	55.8	0.03
n-Butane	0.2610	58.1	257.1	39.4	0.02
i-Pentane	0.1550	72.2	152.7	29.0	0.01
n-Pentane	0.1020	72.2	100.5	19.1	0.01
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	143.8	32.7	0.02
Heptanes	0.0930	100.2	91.6	24.2	0.01
Octanes	0.0440	114.2	43.4	13.0	0.01
Nonanes	0.0160	128.3	15.8	5.3	0.00
Decanes +	0.0050	142.3	4.9	1.8	0.00
Benzene	0.0270	78.1	26.6	5.5	0.00
Toluene	0.0190	92.1	18.7	4.5	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	10.8	3.0	0.00
n-Hexane	0.1460	86.2	143.8	32.7	0.02
Nitrogen	0.0940	28.0	92.6	6.8	0.00
Carbon Dioxide	2.5280	44.0	2,490.7	288.8	0.14
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600			422.43	0.21
HAPS Subtotal	0.2030			45.72	0.02
Total	100.1460			4876.06	2.44

Calculation
$$\text{lb/hr} = (\text{Mol \%} * \text{SumSCF/yr}) / \text{scf/lb-mol}$$
^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.^b Fugitive emission factors from Subpart W, Table W-1A

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																																																																																																														
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<p>Wellsite Heater Inventory:</p> <table style="width: 100%; margin-top: 20px;"> <tr> <td style="width: 30%;"></td> <td style="width: 20%; text-align: center;">Heating Value (Mbtu/hr)</td> <td style="width: 20%; text-align: center;">Fuel Consumption (MMScf/yr)</td> <td style="width: 30%;"></td> </tr> <tr> <td style="text-align: center;">Separator Heater</td> <td style="text-align: center;">750</td> <td style="text-align: center;">6.44</td> <td>* Heater treater size based on industry standard</td> </tr> </table> <table style="width: 100%; margin-top: 20px;"> <tr> <td style="width: 30%;">Annual Run Time:</td> <td style="width: 20%; text-align: center;">8760</td> <td style="width: 20%;">Hours/Year</td> <td style="width: 30%;"></td> </tr> <tr> <td>Fuel Gas Heat Value:</td> <td style="text-align: center;">1,020</td> <td>Btu/scf (Standard heating value from AP-42)</td> <td></td> </tr> </table> <p>Equations:</p> <p style="margin-left: 40px;"> Fuel Consumption (MMscf/yr) = $\frac{\text{Heater Size (MBtu/hr)} * 1,000 \text{ (Btu/MBtu)} * \text{Hours of Operation (hrs/yr)}}{\text{Fuel Heat Value (Btu/scf)} * 1,000,000 \text{ (scf/MMscf)}}$ </p> <p style="margin-left: 40px;"> NOx/CO/TOC Emissions (tons/yr) = $\frac{\text{AP-42 E.Factor (lbs/MMscf)} * \text{Fuel Consumption (MMscf/yr)} * \text{Fuel heating Value (Btu/scf)}}{2,000 \text{ (lbs/ton)} * 1,020 \text{ (Btu/scf - Standard Fuel Heating Value)}}$ </p> <table border="1" style="width: 100%; border-collapse: collapse; margin-top: 20px;"> <thead> <tr> <th></th> <th style="text-align: center;">Emission Factor (lb/MMscf)</th> <th style="text-align: center;">Separator Heater Total Emissions (Tons/Year)</th> <th style="text-align: center;">Total Emissions (Tons/Year)</th> <th style="text-align: center;">Total Emissions (Tons/Year)</th> <th style="text-align: center;">Total Emissions (Tons/Year)</th> <th style="text-align: center;">Total Emissions (Tons/Year) ^e</th> </tr> </thead> <tbody> <tr> <td colspan="7"><i>Criteria Pollutants & VOC</i></td> </tr> <tr> <td>NOx ^a</td> <td style="text-align: center;">100</td> <td style="text-align: center;">0.3221</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.3221</td> </tr> <tr> <td>CO ^a</td> <td style="text-align: center;">84.0</td> <td style="text-align: center;">0.2705</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.2705</td> </tr> <tr> <td>VOC</td> <td style="text-align: center;">5.5</td> <td style="text-align: center;">0.0177</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0000</td> <td style="text-align: center;">0.0177</td> </tr> <tr> <td>SO₂ ^b</td> <td style="text-align: center;">0.00</td> <td style="text-align: center;">0.0000</td> 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Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu. </p>			Heating Value (Mbtu/hr)	Fuel Consumption (MMScf/yr)		Separator Heater	750	6.44	* Heater treater size based on industry standard	Annual Run Time:	8760	Hours/Year		Fuel Gas Heat Value:	1,020	Btu/scf (Standard heating value from AP-42)			Emission Factor (lb/MMscf)	Separator Heater Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year) ^e	<i>Criteria Pollutants & VOC</i>							NOx ^a	100	0.3221	0.0000	0.0000	0.0000	0.3221	CO ^a	84.0	0.2705	0.0000	0.0000	0.0000	0.2705	VOC	5.5	0.0177	0.0000	0.0000	0.0000	0.0177	SO ₂ ^b	0.00	0.0000	0.0000	0.0000	0.0000	0.0000	TSP ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245	PM ₁₀ ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245	PM _{2.5} ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245	<i>Hazardous Air Pollutants</i>							Benzene ^d	2.10E-03	0.0000	0.0000	0.0000	0.0000	0.0000	Toluene ^d	3.40E-03	0.0000	0.0000	0.0000	0.0000	0.0000	Hexane ^d	1.80	0.0058	0.0000	0.0000	0.0000	0.0058	Formaldehyde ^d	7.50E-02	0.0002	0.0000	0.0000	0.0000	0.0002	<i>Greenhouse Gases</i>							CO ₂ ^f	120,162	386.9918	0.0000	0.0000	0.0000	386.9918	CH ₄ ^f	2.27	0.0073	0.0000	0.0000	0.0000	0.0073	N ₂ O ^f	0.23	0.0007	0.0000	0.0000	0.0000	0.0007
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Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																																																																																																																																																																						
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<p>Calculation:</p> <p>Scf/yr = (Mol% * scf/bbl * bbl/day * days/yr) / 100</p> <p>lb/yr = (scf/yr * mol wt.) / scf/lb-mol</p> <p>* Production and gas to oil ratio based on basin specific differences. Please see "Gas Stream Molar Ratios" tab and report for additional information.</p>																																																																																																																																																																																																							

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																								
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Production Phase
Truck Loading Emissions

AP - 42, Chapter 5.2

$$L_L = 12.46 \times S \times P \times M / T$$

L_L = Loading Loss Emission Factor (lbs VOC/1000 gal loaded)
 S = Saturation Factor
 P = True Vapor Pressure of the Loaded Liquid (psia)
 M = Vapor Molecular Weight of the Loaded Liquid (lbs/lbmol)
 T = Temperature of Loaded Liquid (°R)

$$\text{VOC Emissions (tpy)} = \frac{L_L \text{ (lbs VOC/1000 gal)} \times 42 \text{ gal/bbl} \times 365 \text{ days/year} \times \text{production (bbl/day)}}{1000 \text{ gal} \times 2000 \text{ lbs/ton}}$$

S^1	$P \text{ (psia)}^2$	$M \text{ (lb/lbmol)}^3$	$T \text{ (°F)}^4$	$T \text{ (°R)}$	L_L (lb/1000 gal)	Production (bbl/day)	VOC (tpy)
0.6	4.20	66.00	50.00	509.67	4.07	10.0	0.31

- Notes:
1. Saturation factor from AP-42, Table 5.2-1 (Submerged loading: dedicated normal service)
 2. True vapor pressure is estimated from AP-42, Table 7.1-2 assuming an average daily temperature of either 40 or 50 deg F and an RVP of 10.0.
 3. Molecular weight liquid vapor is estimated from AP-42, Table 7.1-2 assuming an RVP of 10.0.
 4. Temperature based on the annual average temperature for basin location (either 40 or 50 degrees F based on options provided in AP-42 Table 7.1-2)

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin

Well Type: Natural Gas

Production Phase
Pumpjack Unit Emissions

Assumptions:

Pumpjack engines only included at oil wells

Pumpjack Horsepower Rating: 0.0 Horsepower
 Load Factor: 0.54
 Brake Specific Fuel Consumption: 0 Btu/hp-hr
 Annual Operation: 8,760 Hours/Year

Equations:

Emissions (lbs/hr) =
$$\frac{\text{Emission Factor (g/hp-hr)} * \text{Power (hp)}}{453.6 \text{ g/lb}}$$

Pollutant	Emission Factor ^a (lb/MMBtu)	Emission Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
<i>Criteria Pollutants & VOC</i>				
NOx		2.80	0.00	0.0000
CO		4.80	0.00	0.0000
VOC	0.12	-	0.0000	0.0000
PM₁₀ ^b	4.83E-02	-	0.00E+00	0.00E+00
PM_{2.5} ^b	4.83E-02	-	0.00E+00	0.00E+00
SO₂	5.88E-04	-	0.0000	0.0000
<i>Hazardous Air Pollutants</i>				
Benzene	1.94E-03	-	0.00E+00	0.00E+00
Toluene	9.63E-04	-	0.00E+00	0.00E+00
Ethylbenzene	1.08E-04	-	0.00E+00	0.00E+00
Xylenes	2.68E-04	-	0.00E+00	0.00E+00
Formaldehyde	5.52E-02	-	0.0000	0.0000
n-Hexane	4.45E-04	-	0.00E+00	0.00E+00
<i>Greenhouse Gases</i>				
CO₂ ^c	117	-	0.00	0
CH₄	0.002	-	0.0000	0.0000
N₂O	0.0002	-	0.0000	0.0000

a AP-42 Table 3.2-3 Uncontrolled Emission Factors for 4-Stroke Rich-Burn Engines, 7/00; and Subpart JJJJ for NOX and CO emission rates.

b PM = sum of PM filterable and PM condensable

c Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.

- Network website for the 1999 National-Scale Air Toxics Assessment at <http://www.epa.gov/ttn/atw/nata1999/nsata99.html>

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Production Phase

Wellsite Dehydrator Emissions

Assumptions:

Number of Dehy Units: 0 Units

Calculations:

Calculations and specifications derived from Pinedale Anticline Final SEIS
GRI-GLYCalc 4.0 operated with: 4 MMSCFD, 0.32 gpm glycol flow, average representative
gas analysis, and 95% control efficiency

Emissions:

Species	Total Project Emissions (tons/year)
Total VOC	0.000
<i>Hazardous Air Pollutants</i>	
Benzene	0.000
Toluene	0.000
Ethylbenzene	0.000
Xylenes	0.000
n-Hexane	0.000
<i>Greenhouse Gases</i>	
CO₂	0.000
CH₄^a	0.000
N₂O	0.000

Note, no greenhouse gas emissions included for dehydrator in Pinedale EIS

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin

Well Type: Natural Gas

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks: 50 Trips/Location
 Light Duty Haul Trucks: 0 Trips/Location Total Trips: 50 Trips

Heavy Duty Haul Trucks: 2 Trips/Location
 Water Trucks: 40 Trips/Location Total Trips: 42 Trips

* Miles and number of trips based on research and industry knowledge;
 please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (g/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NOx	7.44E-02	6.25E-02	7.39E-03	7.39E-03	6.99E-02
CO	1.98E-02	1.66E-02	7.26E-02	7.26E-02	8.92E-02
VOC	3.16E-03	2.65E-03	3.54E-03	3.54E-03	6.19E-03
SO2	4.57E-05	3.84E-05	2.83E-05	2.83E-05	6.67E-05
PM10	4.22E-03	3.54E-03	1.94E-04	1.94E-04	3.74E-03
PM2.5	4.09E-03	3.44E-03	1.79E-04	1.79E-04	3.61E-03
CO2	1.88E+00	1.58E+00	1.13E+00	1.13E+00	2.70E+00
CH4	7.61E-05	6.39E-05	4.56E-05	4.56E-05	1.10E-04
N2O	1.52E-05	1.28E-05	9.13E-06	9.13E-06	2.19E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

c Assumes maximum development scenario

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Production Phase
Pneumatic Device Emissions

Wellsite Pneumatic Inventory:

		Classification	Quantity	Emission Factor (Scf/hr/unit)
Devices:	Dump Valve	Intermittent Bleed	2	13.50
	Pneumatic Controller	Low Bleed	1	1.39
			0	0.00
Pumps:	Chemical Pump	Pneumatic Pump	1	
	Sandpiper	Pneumatic Pump	1	13.30

Annual Equipment Run Time: 8760 Hours/Year 379.49 Scf/lb-mol
Pneumatic Device Control: ^b 0 Percent

* Low bleed and intermittent bleed emission factors (scf/hr) based on Subpart W, Table W-1A
* Quantity of devices based on typical industry values

Component	Mole %	Mole Weight lb/lb-mol	Dump Valve Tons/Year	Pneumatic Controller Tons/Year	(None) Tons/Year	Pneumatic Pumps Tons/Year	Total Tons/Year
Methane	88.9720	16.0	4.448	0.229	0.000	4.382	9.059
Ethane	5.7920	30.1	0.543	0.028	0.000	0.535	1.105
Propane	1.3650	44.1	0.188	0.010	0.000	0.185	0.382
i-Butane	0.3700	58.1	0.067	0.003	0.000	0.066	0.136
n-Butane	0.2610	58.1	0.047	0.002	0.000	0.047	0.096
i-Pentane	0.1550	72.2	0.035	0.002	0.000	0.034	0.071
n-Pentane	0.1020	72.2	0.023	0.001	0.000	0.023	0.047
Other Pentanes	0.0000	70.1	0.000	0.000	0.000	0.000	0.000
Hexanes	0.1460	86.2	0.039	0.002	0.000	0.039	0.080
Heptanes	0.0930	100.2	0.029	0.001	0.000	0.029	0.059
Octanes	0.0440	114.2	0.016	0.001	0.000	0.015	0.032
Nonanes	0.0160	128.3	0.006	0.000	0.000	0.006	0.013
Decanes +	0.0050	142.3	0.002	0.000	0.000	0.002	0.005
Benzene	0.0270	78.1	0.007	0.000	0.000	0.006	0.013
Toluene	0.0190	92.1	0.005	0.000	0.000	0.005	0.011
Ethylbenzene	0.0000	106.2	0.000	0.000	0.000	0.000	0.000
2,2,4 Trimethylpentane	0.0000	78.1	0.000	0.000	0.000	0.000	0.000
Xylenes	0.0110	106.2	0.004	0.000	0.000	0.004	0.007
n-Hexane	0.1460	86.2	0.039	0.002	0.000	0.039	0.080
Nitrogen	0.0940	28.0	0.008	0.000	0.000	0.008	0.017
Carbon Dioxide	2.5280	44.0	0.347	0.018	0.000	0.342	0.706
Hydrogen Sulfide	0.0000	34.1	0.000	0.000	0.000	0.000	0.000

VOC Subtotal	2.8	1492.8	0.51	0.03	0.00	0.50	1.03
HAPS Subtotal	0.2	546.9	0.05	0.00	0.00	0.05	0.11
Total	100.1	1645.0	5.85	0.30	0.00	5.77	11.92

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b 98% control input is a result of the Wyoming Department of Environment Quality requirement, and only pertains to the Upper Green River Basin.

APPENDIX B

EMISSION INVENTORY FOR THE UINTA/PICEANCE BASIN GAS WELL

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Location Selection:

Geography: **Well Type:**
 Uinta/Piceance Basin Natural Gas

- Choose geography/basin, and well type will automatically fill
- < Choose Uinta/Piceance Basin for deep gas wells with little condensate
- < Choose Upper Green River Basin for deep gas wells with dehydrators and higher condensate
- < Choose San Juan Basin for shallow gas wells with little to no condensate
- < Choose Williston Basin for deep oil wells with high gas
- < Choose Denver Basin for shallow oil wells with low gas

If the user wants to change any specifications, do so within the "Constants and References" tab, as all other tabs connect to it.

Pollutant:	Total Emissions (Tons per Year)								
	NO _x	CO	VOC	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O
Construction Phase:	0.47	0.29	0.04	0.0001	1.99	0.06	33.84	0.001	0.0003
Development Phase:	14.77	3.15	0.74	0.0002	4.89	0.49	2127.69	1.12	0.0516
Operation Phase:	0.39	0.36	2.62	0.0001	0.04	0.23	390.55	11.09	0.0008
Total:	15.63	3.80	3.40	0.0004	6.93	0.78	2552.08	12.21	0.0526

Pollutant:	Total Emissions (Tons per Year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	HAPs
Construction Phase:	0.00	0.00	0.00	0.00	0.00	0.00
Development Phase:	1.36	0.95	0.0000	0.55	7.31	10.18
Operation Phase:	0.03	0.01	0.00003	0.009	0.16	0.21
Total:	1.39	0.97	0.00003	0.56	7.46	10.39

CO ₂ equivalent (Global Warming Potential)	
Total TPY:	2824.87
CO ₂ equivalent conversions:	
CO ₂	1.00
CH ₄	21.00
N ₂ O	310.00

H ₂ S Emissions	
Total TPY:	0.00

* If H₂S in gas, input value in "Gas Stream Molar Ratios" tab, and potential emissions will calculate here. Current assumption is no H₂S in gas stream.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Road Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	4	Days/Location	(Typical Value)
	48.0	Dozer Hours/Location	(Typical Value)
	48.0	Backhoe Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅ (AP-42 Table 11.9-1, 7/98)		
PM _{2.5} Multiplier:	0.105 * TSP (AP-42 Table 11.9-1, 7/98)		

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98 & 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0473	1.97	0.0473	0.0946
PM₁₅	0.50	0.0120	0.50	0.0120	0.0241
PM₁₀	0.38	0.0090	0.38	0.0090	0.0181
PM_{2.5}	0.21	0.0050	0.05	0.0013	0.0062

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase
Road Grader Particulate Matter

Assumptions:

Grading Length:	6.00	miles	(Typical Value)
Construction Schedule:	3	Days/Location	(Typical Value)
	12	Hours/Day	(Typical Value)
	36	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	
Average Grader Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 16.12 lbs TSP/Location

Emissions = 7.71 lbs PM₁₅/Location

Grader Construction Emissions			
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	16.12	0.45	8.06E-03
PM₁₅	7.71	0.21	3.86E-03
PM₁₀	4.63	0.13	2.31E-03
PM_{2.5}	0.50	0.01	2.50E-04

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Well Pad Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7	Days/Location		(Typical Value)
	10	Hours/Day		(Typical Value)
	70	Hours/Location	(Dozer)	(Typical Value)
	70	Hours/Location	(Back Hoe)	(Typical Value)
Watering Control Efficiency:	50	Percent (%)		(Typical Value)
Soil Moisture Content:	7.9	Percent (%)		AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)		AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)		
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)		

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase
Well Pad Grader Particulate Matter

Assumptions:

Construction Schedule:	4.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	40	Hours/Location	(Typical Value)
Watering Control Efficiency	50	Percent (%)	(Typical Value)
Average Grader Speed	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
Distance Graded	2.84	Miles/Location	(Typical Value)
PM ₁₀ Multiplier	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 7.63 lbs TSP/well pad

Emissions = 3.65 lbs PM₁₅/well pad

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	7.63	0.19	0.0038
PM₁₅	3.65	0.09	0.0018
PM₁₀	2.19	0.05	0.0011
PM_{2.5}	0.24	0.01	0.0001

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Pipeline Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Pipeline Grader Particulate Matter

Assumptions:

Distance Graded:	12.50	Miles/Location	(Typical Value)
Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Mean Vehicle Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs) = $0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs) = $0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions = 33.58 lbs TSP/well

Emissions = 16.07 lbs PM₁₅/well

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	33.58	0.48	0.0168
PM₁₅	16.07	0.23	0.0080
PM₁₀	9.64	0.14	0.0048
PM_{2.5}	1.04	0.01	0.0005

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Heavy Diesel Truck Trips:

Road Construction:	7	Trips			
Well Pad Construction:	8	Trips	Total Trips:	21	Trips
Pipeline Construction:	6	Trips			

Light Duty Pickup Truck Trips:

Road Construction:	16	Trips			
Well Pad Construction:	28	Trips	Total Trips:	100	Trips
Pipeline Construction:	56	Trips			

* All assumptions above are based on typical industry values

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a	Emissions	E. Factor ^b	Emissions	Emissions
	(lb/mile)	(Tons/Location)	(lb/mile)	(Tons/Location)	(Tons/Location)
NOx	7.44E-02	3.12E-02	7.39E-03	1.48E-02	4.60E-02
CO	1.98E-02	8.32E-03	7.26E-02	1.45E-01	1.54E-01
VOC	3.16E-03	1.33E-03	3.54E-03	7.08E-03	8.41E-03
SO2	4.57E-05	1.92E-05	2.83E-05	5.66E-05	7.58E-05
PM10	4.22E-03	1.77E-03	1.94E-04	3.88E-04	2.16E-03
PM2.5	4.09E-03	1.72E-03	1.79E-04	3.58E-04	2.08E-03
CO2	1.88	0.79	1.13	2.25	3.04
CH4	7.61E-05	3.19E-05	4.56E-05	9.13E-05	1.23E-04
N2O	1.52E-05	6.39E-06	9.13E-06	1.83E-05	2.46E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Construction Phase

Construction Heavy Equipment Tailpipe Emissions

Assumptions:

Fuel and Engine:

Brake Specific Fuel Consumption, Avg. (BSFC) 8250 btu/hp-hr (Typical Value)
Diesel Higher Heating Value (HHV) 0.138 mmBtu/Gallon (Typical Value)

Trackhoe:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 100 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Tractors/Loaders/Backhoes)

Dozer:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 140 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Crawler Tractor/Dozers)

Grader:

Working Hours 130 Total Hours (Typical Value)
Rated Horsepower 250 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Graders)

Total Horsepower Hours: 45795.8 Hp-hrs (Sum of all horsepower above)
Total Fuel Usage: 2737.79 Gallons Diesel Fuel

Equations:

Total Fuel Usage: (btu-hp-hr * hp-hrs) / Mmbtu-gal) / 1,000,000
Emissions (tons/year/pad) = $\frac{\text{Emission Factor (g/mile)} * \text{Trip Distance (miles)} * \text{Load Factor}}{453.6 \text{ (g/lb)} * 2000 \text{ (lb/tons)}}$

Heavy Const. Vehicles	Backhoe			Dozer			Grader		
	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
NOx	8.38	1.09E+00	1.02E-01	8.38	1.53E+00	1.43E-01	8.38	2.72E+00	1.77E-01
CO	2.7	3.51E-01	3.30E-02	2.7	4.92E-01	4.62E-02	2.7	8.78E-01	5.71E-02
VOC ^b	0.68	8.84E-02	8.31E-03	0.68	1.24E-01	1.16E-02	0.68	2.21E-01	1.44E-02
PM₁₀	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03
PM_{2.5}	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03

Heavy Const. Vehicles	Total Emissions ^c (tons/yr)
NOx	0.42
CO	0.14
VOC	0.03
PM₁₀	0.02
PM_{2.5}	0.02

Greenhouse Gas Emissions:

	Diesel EF kg/mmBtu	Emissions lbs	Emissions Tons
CO ₂	73.96	61604.19	30.80
CH ₄	0.003	2.50	0.0012
N ₂ O	0.0006	0.50	0.0002

a From Table A-4 of Exhaust and Crankcase Emission Factors for NONROAD Engine Modeling - Compression Ignition, EPA-420-R-10-018, July 2010.

b Emission Factor represents total Hydrocarbon Emissions

c Converted from emission factor for Distillate Fuel Oil #2 (diesel) as listed in Table C-1 to Subpart C of Part 98 - Default Emission Factors and High Heat Values for Various Types of Fuel.

Listed Factor:

73.96 kg CO₂/mmBtu
393 hp-hr = mmBtu
188.2 g CO₂/hp-hr

Kleinfelder, Inc. Wellsite Emissions		Base Location: Uinta/Piceance Basin Well Type: Natural Gas													
Construction Phase															
Wind Erosion Fugitive Dust															
Assumptions:															
Threshold Friction Velocity (U _t)	1.02 1.33	m/s (2.28 mph) for well pads (AP-42 Table 13.2.5-2 Overburden - Western Surface Coal Mine) m/s (2.97 mph) for roads (AP-42 Table 13.2.5-2 Roadbed material)													
Initial Disturbance Area															
Total Access Road/ROW Area Per Location:	976,800	Square Meters	(Typical Value)												
Total Well Pad Area Disturbed Per Location:	50,000	Square Meters	(Typical Value)												
Total Area Disturbed Per Location:	1,026,800	Square Meters	(Typical Value)												
Exposed Surface Type	Flat														
Meteorological Data	2002 Grand Junction (obtained from NCDC website)														
Fastest Mile Wind Speed:	45	miles/hour	(Typical Value)												
Fastest Mile Wind Speed (U ₁₀ ⁺)	20.12	meters/sec (45 mph) reported as fastest 2-minute wind speed for Grand Junction (2002)													
Number soil of disturbances	1.00	for well pads (Assumption, disturbance at construction and reclamation) constant for dirt roads													
Equations (AP-42 13.2.5.2 Industrial Wind Erosion)															
Friction Velocity U* = 0.053 U ₁₀ ⁺															
Erosion Potential P (g/m ² /period) = 58*(U*-U _t *) ² + 25*(U*-U _t *) for U*>U _t *, P = 0 for U*< U _t *															
Emissions (tons/year) = Erosion Potential(g/m ² /period)*Disturbed Area(m ²)*Disturbances/year*(k)/(453.6 g/lb)/2000 lbs/ton/Develop Period															
<table><tr><th colspan="3">Particle Size Multiplier (k)</th></tr><tr><th>30 μm</th><th><10 μm</th><th><2.5 μm</th></tr><tr><td>1.0</td><td>0.5</td><td>0.075</td></tr></table>				Particle Size Multiplier (k)			30 μm	<10 μm	<2.5 μm	1.0	0.5	0.075			
Particle Size Multiplier (k)															
30 μm	<10 μm	<2.5 μm													
1.0	0.5	0.075													
<table><tr><th>Maxium U₁₀⁺ Wind Speed (m/s)</th><th>Maximum U* Friction Velocity m/s</th><th>Well U_t* Threshold Velocity^a m/s</th><th>Well Pad Erosion Potential g/m²</th><th>Road U_t* Threshold Velocity^a m/s</th><th>Road Erosion Potential g/m²</th></tr><tr><td>20.12</td><td>1.07</td><td>1.02</td><td>1.28</td><td>1.33</td><td>0.00</td></tr></table>				Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²	20.12	1.07	1.02	1.28	1.33	0.00
Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²										
20.12	1.07	1.02	1.28	1.33	0.00										
Wind Erosion Emissions															
<table><tr><th>Particulate Species</th><th>Well Pad (tons/year)</th><th>Roads/Pipelines (tons/year)</th></tr><tr><td>TSP</td><td>7.05E-02</td><td>0.00E+00</td></tr><tr><td>PM₁₀</td><td>3.52E-02</td><td>0.00E+00</td></tr><tr><td>PM_{2.5}</td><td>5.28E-03</td><td>0.00E+00</td></tr></table>				Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)	TSP	7.05E-02	0.00E+00	PM ₁₀	3.52E-02	0.00E+00	PM _{2.5}	5.28E-03	0.00E+00
Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)													
TSP	7.05E-02	0.00E+00													
PM ₁₀	3.52E-02	0.00E+00													
PM _{2.5}	5.28E-03	0.00E+00													

Kleinfelder, Inc.				Base Location: Uinta/Piñon Basin					
Website Emissions				Well Type: Natural Gas					
Construction, Development, and Production Phase									
Construction, Development, and Operations Traffic Fugitive Dust Emissions									
Assumptions:									
				Round Trip Miles	40				
				Round Trip (Paved) Miles	16				
				Round Trip (Un-Paved) Miles	24				
				Precipitation Days (P)	45				
Unpaved Calculation AP-42, Chapter 13.2.2				$E (PM_{10}) / VMT = 1.5 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
November 2006				$E (PM_{2.5}) / VMT = 0.15 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
				Silt Content (S)	8.5		AP 42 13.2.2-1 Mean Silt Content Construction Sites		
Paved Calculation AP-42, Chapter 13.2.1				$E (PM_{10}) / VMT = 0.0022 * (sL)^{0.91} * (W)^{0.02} * (1-(P/(365*4)))$					
January 2011				$E (PM_{2.5}) / VMT = 0.00054 * (sL)^{0.91} * (W)^{0.02} * (1-(P/(365*4)))$					
				Silt Loading (sL)	0.6		AP-42 Table 13.2.1-2 baseline low volume roads		
Unpaved Calculations:									
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	3.09	1558.9	0.8	0.3	155.9	0.1
	Light Duty Pickup Trucks	5,000	100	0.89	2131.8	1.1	0.1	213.2	0.1
	Total:				3690.67	1.85		369.07	0.18
	Paved Calculations:								
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	0.0576	19.4	0.0097	0.014	4.8	0.0024
	Light Duty Pickup Trucks	5,000	100	0.0034	5.5	0.0027	0.001	1.3	0.0007
	Total:				24.8	0.0		6.1	0.0
	Unpaved Calculations:								
Development Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	84	0.89	1790.7	0.9	0.1	179.1	0.1
	Light Duty Haul Trucks	7,500	11	1.07	281.4	0.1	0.1	28.1	0.0
	Heavy Duty Haul Trucks	80,000	67	3.09	4973.6	2.5	0.3	497.4	0.2
	Water Trucks	70,000	24	2.91	1677.7	0.8	0.3	167.8	0.1
	Total:				8723.41	4.36		872.34	0.44
	Paved Calculations:								
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips						
	Light Duty Pickup Trucks:	5000	84	0.00	4.6	0.0	0.0	1.1	0.0006
	Light Duty Haul Trucks	7500	11	0.01	0.9	0.0	0.0	0.2	0.0001
Heavy Duty Haul Trucks	80000	67	0.06	61.8	0.0	0.0	15.2	0.0076	
Water Trucks	70,000	24	0.05	19.3	0.0	0.0	4.7	0.0024	
Total:				86.6	0.0		21.2	0.0	
Unpaved Calculations:									
Production Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	50	0.89	1065.89	0.53	0.0888	106.59	0.0533
	Light Duty Haul Trucks	7,500	0	1.07	0.00	0.00	0.1066	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	3.09	148.47	0.07	0.3093	14.85	0.0074
	Water Trucks	70,000	40	2.91	2796.14	1.40	0.2913	279.61	0.1398
	Total:				4010.50	2.01		401.05	0.20
	Paved Calculations:								
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	50	0.00	2.73	0.0014	0.0008	0.67	0.0003
	Light Duty Haul Trucks	7,500	0	0.01	0.00	0.0000	0.0013	0.00	0.0000
Heavy Duty Haul Trucks	80,000	2	0.06	1.84	0.0009	0.0141	0.45	0.0002	
Water Trucks	70,000	40	0.05	32.18	0.0161	0.0123	7.90	0.0039	
Total:				36.75	0.02		9.02	0.00	
Annual Total					Unpaved Roads PM ₁₀ (tons) 8.21			Unpaved Roads PM _{2.5} (tons) 0.8	
					Paved Roads PM ₁₀ 0.1			Paved Roads PM _{2.5} 0.0	
					Total:			8.3	
								0.8	

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Development Phase

Drill Rig Emissions

Assumptions:

Parameter	Value
Days of Operation	18 (Typical Value)
Hours of Operation	432 (Typical Value)
Diesel Fuel Sulfur Content	0.000015 (Typical Value)

Parameter	Value	Units
BSFC (Avg.)	8250 (Typical Value)	btu/hp-hr
Diesel HHV	0.138 (Typical Value)	mmbtu/gal

Engine	HP *	Load Factor	Run time (hrs)	Total Hp-hrs
Vertical Drill Rig Engine	475	0.42	144	28728
Horizontal Drill Rig Engine 1	2,950	0.59	288	501264
Horizontal Drill Rig Engine 2	2,950	0.59	432	751896
Drill Rig Generator	350	0.42	432	63504
Trailers Generator	150	0.42	432	27216
Air Compressor	550	0.42	144	33264
Air Compressor	550	0.42	144	33264
Air Compressor	550	0.42	144	33264
Air Compressor	550	0.42	144	33264
Air Compressor Booster	650	0.42	144	39312
Forklift	120	0.42	144	7257.6
Aerial Lift	50	0.42	16	336
Frontend loader	150	0.42	16	1008
Dozer	175	0.42	9	661.5

Total HP 10,220

Total: 1,554,239 Hp-hrs

Fuel Usage: 92,916 Gallons of Diesel Total Fuel Usage: (btu/hp-hr * hp-hrs) * gal/btu

Greenhouse Gasses:

	Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location
CO2	73.96	2090751.53	1045.38
CH4	0.003	84.81	0.04
N2O	0.0006	16.96	0.01

Greenhouse gas emission factors from Subpart C, Table C-1 and C-2

Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)
Vertical Drill Rig Engine	28728	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Horizontal Drill Rig Engine 1	501264	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Horizontal Drill Rig Engine 2	751896	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Drill Rig Generator	63504	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Trailers Generator	27216	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor Booster	39312	1.3272	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Forklift	7257.6	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Aerial Lift	336	5.0000	6.9000	0.8000	0.7760	1.27E-05	1.8000	7.76E-04	2.81E-04	1.93E-04
Frontend loader	1008	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Dozer	661.5	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04

Engine	CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)
Vertical Drill Rig Engine	0.02420	0.12984	0.00417	0.00404	4.02E-07	0.00518	0.00009	0.00003	0.00002
Horizontal Drill Rig Engine 1	0.42226	2.26545	0.07272	0.07053	7.02E-06	0.09040	0.00160	0.00058	0.00040
Horizontal Drill Rig Engine 2	0.63339	3.39817	0.10907	0.10580	1.05E-05	0.13560	0.00241	0.00087	0.00060
Drill Rig Generator	0.18900	0.58661	0.02814	0.02730	8.89E-07	0.04760	0.00020	0.00007	0.00005
Trailers Generator	0.08100	0.25140	0.01206	0.01170	3.81E-07	0.02040	0.00009	0.00003	0.00002
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor Booster	0.05751	0.17767	0.00570	0.00553	5.50E-07	0.00709	0.00013	0.00005	0.00003
Forklift	0.02160	0.06704	0.00322	0.00312	1.02E-07	0.00544	0.00002	0.00001	0.00001
Aerial Lift	0.00185	0.00256	0.00030	0.00029	4.70E-09	0.00067	0.00000	0.00000	0.00000
Frontend loader	0.00300	0.00931	0.00045	0.00043	1.41E-08	0.00076	0.00000	0.00000	0.00000
Dozer	0.00197	0.00611	0.00029	0.00028	9.26E-09	0.00050	0.00000	0.00000	0.00000
Total:	1.55935	7.52998	0.25541	0.24775	0.00002	0.33762	0.00498	0.00180	0.00124

Emission Factors

- Drill rig emission factors based on Tier II engines
- All other engine emission factors based on Tier 0 engines (typical values)
- HAP emission factors from AP-42 Volume I, Large Stationary Diesel Engines Table 3.4-3

Calculations:

ton/year: (Total hp-hr * g/hp-hr) * lb-gram / lb-ton

*** Drill rig horsepower developed based on:**

- 1 Williston Basin: 2,100 from Jonah, Wyoming RMP
- 2 San Juan Basin: 2,100 from River Valley RMP
- 3 Upper Green River Basin: 2,100 from Jonah, Wyoming RMP
- 4 Denver Basin: 2,950 from River Valley RMP
- 5 Uintah Basin: 2,952 from River Valley RMP

Note, runtime for each drilling event is based on research and industry experience dependent upon each basi

Kleinfelder, Inc. Wellsite Emissions				Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																		
Development Phase																																						
Conductor Pipe Set Emissions																																						
Assumptions:																																						
<table><tr><th>Parameter</th><th>Value</th></tr><tr><td>Days of Operation</td><td>2</td></tr><tr><td>Hours of Operation</td><td>24</td></tr><tr><td>Diesel Fuel Sulfur Content</td><td>0.000015</td></tr></table>		Parameter	Value	Days of Operation	2	Hours of Operation	24	Diesel Fuel Sulfur Content	0.000015	<table><tr><th>Parameter</th><th>Value</th><th>Units</th></tr><tr><td>BSFC (Avg.)</td><td>8250</td><td>btu/hp-hr</td></tr><tr><td>Diesel HHV</td><td>0.138</td><td>mmbtu/gal</td></tr></table> (Typical Value) (Typical Value)						Parameter	Value	Units	BSFC (Avg.)	8250	btu/hp-hr	Diesel HHV	0.138	mmbtu/gal														
Parameter	Value																																					
Days of Operation	2																																					
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BSFC (Avg.)	8250	btu/hp-hr																																				
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Workovers:				Greenhouse Gases:																																		
<table><tr><th>Engine</th><th>HP</th><th>Load Factor</th><th>Run time (hrs)</th><th>Total Hp-hrs</th></tr><tr><td>Rig Engine</td><td>350</td><td>0.42</td><td>24</td><td>3528</td></tr><tr><td>Rig Generator</td><td>50</td><td>0.42</td><td>24</td><td>504</td></tr></table>				Engine	HP	Load Factor	Run time (hrs)	Total Hp-hrs	Rig Engine	350	0.42	24	3528	Rig Generator	50	0.42	24	504	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>5423.82</td><td>2.71</td></tr><tr><td>CH4</td><td>0.003</td><td>0.22</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.04</td><td>0.00</td></tr></table>					Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	5423.82	2.71	CH4	0.003	0.22	0.00	N2O	0.0006	0.04	0.00
Engine	HP	Load Factor	Run time (hrs)	Total Hp-hrs																																		
Rig Engine	350	0.42	24	3528																																		
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	Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location																																			
CO2	73.96	5423.82	2.71																																			
CH4	0.003	0.22	0.00																																			
N2O	0.0006	0.04	0.00																																			
Total Horsepower: 400				Greenhouse gas emission factors from Subpart C, Table C-1 and C-2																																		
Total: 4,032 Hp-hrs				Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)																																		
Fuel Usage: 241 Gallons of Diesel																																						
Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)																												
Rig Engine	3528	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	0.0008	0.0003	0.0002																												
Rig Generator	504	5.0000	6.9000	0.8000	0.7760	1.27E-05	1.8000	0.0008	0.0003	0.0002																												
Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																												
Rig Engine		0.00328	0.01686	0.00051	0.00050	0.00000	0.00064	0.00001	0.00000	0.00000																												
Rig Generator		0.00278	0.00383	0.00044	0.00043	0.00000	0.00100	0.00000	0.00000	0.00000																												
Total:		0.00605	0.02069	0.00096	0.00093	0.00000	0.00164	0.00001	0.00000	0.00000																												
Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton * Rig engine emission rates are based on a Tier II engine and rig generator emission rates are based on a Tier 0 engine. * All days, hours, and HP values above are based on typical industry values																																						

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Development Phase

Hydraulic Fracturing Flowback Emissions

Assumptions:

Estimated Frac flowback Rate: 10,000 Scf/hr
Combustion Efficiency: 95.00 Percent (%)
Event Duration: 100.00 Hours
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Venting duration based on research and industry knowledge; please see report for additional information.
* Venting control based on Subpart OOOO requirements of 95% minimum control.
Control efficiency can be deleted if applicable.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr
** Multiply above equation by 0.02 if including 98% control efficiency

Un-combusted Componet Emissions:

Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	444.86	18.81	0.94
Ethane	5.7920	30.1	28.96	2.29	0.11
Propane	1.3650	44.1	6.83	0.79	0.04
i-Butane	0.3700	58.1	1.85	0.28	0.01
n-Butane	0.2610	58.1	1.31	0.20	0.01
i-Pentane	0.1550	72.2	0.78	0.15	0.01
n-Pentane	0.1020	72.2	0.51	0.10	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.73	0.17	0.01
Heptanes	0.0930	100.2	0.47	0.12	0.01
Octanes	0.0440	114.2	0.22	0.07	0.00
Nonanes	0.0160	128.3	0.08	0.03	0.00
Decanes +	0.0050	142.3	0.03	0.01	0.00
Benzene	0.0270	78.1	0.14	0.03	0.00
Toluene	0.0190	92.1	0.10	0.02	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.06	0.02	0.00
n-Hexane	0.1460	86.2	0.73	0.17	0.01
Nitrogen	0.0940	28.0	9.40	0.69	0.03
Carbon Dioxide	2.5280	44.0	252.80	29.32	1.47
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600	1492.8	13.80	2.14	0.11
HAPS Subtotal	0.2030	546.9	1.02	0.23	0.01
Total	100.1460	1645.0	749.82	53.26	2.66

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	8452.34	980.23	49.01
C2	5.79	550.24	63.81	3.19
C3	1.37	129.68	15.04	0.75
C4	0.63	59.95	6.95	0.35
C5+	0.76	72.58	8.42	0.42

CO₂ Total Emissions: 53.72 Tons/Event
N₂O Emissions: 1.13E-04 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.37	3.80	0.19	AP-42 CH13.5-1
NOx	0.068	0.70	0.03	AP-42 CH13.5-1
SO ₂	-	0.00	0.00	*Based on H2s 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																												
Development Phase																																													
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<p>Total Horsepower: 1,500 (Typical Value)</p> <p>Total: 11,760 Hp-hrs</p> <p>Fuel Usage: 724 Gallons of Diesel Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)</p>	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>16298.85</td><td>8.15</td></tr><tr><td>CH4</td><td>0.003</td><td>0.66</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.13</td><td>0.00</td></tr></table>		Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	16298.85	8.15	CH4	0.003	0.66	0.00	N2O	0.0006	0.13	0.00																												
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Total: 0.01436 0.06369 0.00221 0.00214 0.00308 0.00004 0.00000 0.00001 0.00001																																													
Emission Factors - Engine emission factors based on Tier II engines (typical values)																																													
Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																													

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Development Phase
Well Venting During Workover Events

Assumptions:

Significant gas venting only occurs on natural gas wells.

Estimated Venting Rate: 5,000 Scf/Event (Typical Value)
Combustion Efficiency: 0.00 Percent (%)
Event Quantity: 1.00 Event - Assumed one event
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Vented quantity based on research and industry knowledge; please see report for additional information.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf-lb-mol)
** Multiply above equation by 0.02 if including 98% control efficiency

Component	Mole %	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Event
Methane	88.9720	16.0	4448.60	188.07	0.0940
Ethane	5.7920	30.1	289.60	22.95	0.0115
Propane	1.3650	44.1	68.25	7.93	0.0040
i-Butane	0.3700	58.1	18.50	2.83	0.0014
n-Butane	0.2610	58.1	13.05	2.00	0.0010
i-Pentane	0.1550	72.2	7.75	1.47	0.0007
n-Pentane	0.1020	72.2	5.10	0.97	0.0005
Other Pentanes	0.0000	70.1	0.00	0.00	0.0000
Hexanes	0.1460	86.2	7.30	1.66	0.0008
Heptanes	0.0930	100.2	4.65	1.23	0.0006
Octanes	0.0440	114.2	2.20	0.66	0.0003
Nonanes	0.0160	128.3	0.80	0.27	0.0001
Decanes +	0.0050	142.3	0.25	0.09	0.0000
Benzene	0.0270	78.1	1.35	0.28	0.0001
Toluene	0.0190	92.1	0.95	0.23	0.0001
Ethylbenzene	0.0000	106.2	0.00	0.00	0.0000
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.0000
Xylenes	0.0110	106.2	0.55	0.15	0.0001
n-Hexane	0.1460	86.2	7.30	1.66	0.0008
Nitrogen	0.0940	28.0	4.70	0.35	0.0002
Carbon Dioxide	2.5280	44.0	126.40	14.66	0.0073
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.0000

VOC Subtotal	2.7600	1492.8	138.00	21.44	0.0107
HAPS Subtotal	0.2030	546.9	10.15	2.32	0.0012
Total	100.1460	1645.0	5007.30	247.46	0.1237

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	0.00	0.00	0.00
C2	5.79	0.00	0.00	0.00
C3	1.37	0.00	0.00	0.00
C4	0.63	0.00	0.00	0.00
C5+	0.76	0.00	0.00	0.00

CO₂ Total Emissions: 0.00 Tons/Event
N₂O Emissions: 5.67E-07 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NOx	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.000	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions			Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																																			
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Wellsite Development Traffic Tailpipe Emissions																																																																						
Assumptions:																																																																						
Average Round Trip Distance:		40.0	Miles/Trip Average																																																																			
Light Duty Pickup Trucks:		84	Trips/Location																																																																			
Light Duty Haul Trucks		11	Trips/Location		Total Trips: 95 Trips																																																																	
Heavy Duty Haul Trucks		67	Trips/Location																																																																			
Water Trucks		24	Trips/Location		Total Trips: 91 Trips																																																																	
* Miles and number of trips based on research and industry knowledge; please see report for additional information.																																																																						
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Emissions (tons/year) = $\frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$																																																																						
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c Assumes maximum development scenario																																																																						

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																																																																																																																																																		
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<p style="text-align: center;">**Wellhead gas combustion only for Williston Basin wells, due to the regularity of of pit flares combusting all gas coming from the wellhead. If gas being captured, change scf/hr value or hours of event value.</p> <p>Assumptions:</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 35%;">Estimated Gas Flow Rate:</td> <td style="width: 15%;">0</td> <td style="width: 15%;">Scf/hr</td> <td style="width: 35%;"></td> </tr> <tr> <td>Combustion Efficiency:</td> <td>0.00</td> <td>Percent (%)</td> <td></td> </tr> <tr> <td>Event Duration:</td> <td>0.00</td> <td>Hours</td> <td>- Estimated 3 months before sales line</td> </tr> <tr> <td></td> <td>379.49</td> <td>Scf/lb-mol</td> <td>- Typical/Constant Conversion Value</td> </tr> </table> <p style="text-align: center;">* It is assumed that all produced natural gas is sent to a sales line after the well is completed.</p> <p style="text-align: center;">Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr</p> <p style="text-align: center;">** Multiply above equation by 0.05 if including 95% control efficiency</p> <p>Combusted Component Emissions:</p> <table border="1" style="width: 100%; border-collapse: collapse; text-align: center;"> <thead> <tr> <th style="width: 20%;">Component</th> <th style="width: 10%;">Mole % *</th> <th style="width: 10%;">Mole Weight lb/lb-mole</th> <th style="width: 10%;">Emissions Scf/hr</th> <th style="width: 10%;">Emissions lbs/hour</th> <th style="width: 10%;">Emissions Tons/Year</th> </tr> </thead> <tbody> <tr><td>Methane</td><td>88.9720</td><td>16.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethane</td><td>5.7920</td><td>30.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Propane</td><td>1.3650</td><td>44.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Butane</td><td>0.3700</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Butane</td><td>0.2610</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Pentane</td><td>0.1550</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Pentane</td><td>0.1020</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Other Pentanes</td><td>0.0000</td><td>70.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hexanes</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Heptanes</td><td>0.0930</td><td>100.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Octanes</td><td>0.0440</td><td>114.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nonanes</td><td>0.0160</td><td>128.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Decanes +</td><td>0.0050</td><td>142.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Benzene</td><td>0.0270</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Toluene</td><td>0.0190</td><td>92.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethylbenzene</td><td>0.0000</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>2,2,4 Trimethylpentane</td><td>0.0000</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Xylenes</td><td>0.0110</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Hexane</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nitrogen</td><td>0.0940</td><td>28.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Carbon Dioxide</td><td>2.5280</td><td>44.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hydrogen Sulfide</td><td>0.0000</td><td>34.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td colspan="6"> </td></tr> <tr> <td>VOC Subtotal</td> <td>2.7600</td> <td>1492.8</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>HAPS Subtotal</td> <td>0.2030</td> <td>546.9</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>Total</td> <td>100.1460</td> <td>1645.0</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> </tbody> </table>		Estimated Gas Flow Rate:	0	Scf/hr		Combustion Efficiency:	0.00	Percent (%)		Event Duration:	0.00	Hours	- Estimated 3 months before sales line		379.49	Scf/lb-mol	- Typical/Constant Conversion Value	Component	Mole % *	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year	Methane	88.9720	16.0	0.00	0.00	0.00	Ethane	5.7920	30.1	0.00	0.00	0.00	Propane	1.3650	44.1	0.00	0.00	0.00	i-Butane	0.3700	58.1	0.00	0.00	0.00	n-Butane	0.2610	58.1	0.00	0.00	0.00	i-Pentane	0.1550	72.2	0.00	0.00	0.00	n-Pentane	0.1020	72.2	0.00	0.00	0.00	Other Pentanes	0.0000	70.1	0.00	0.00	0.00	Hexanes	0.1460	86.2	0.00	0.00	0.00	Heptanes	0.0930	100.2	0.00	0.00	0.00	Octanes	0.0440	114.2	0.00	0.00	0.00	Nonanes	0.0160	128.3	0.00	0.00	0.00	Decanes +	0.0050	142.3	0.00	0.00	0.00	Benzene	0.0270	78.1	0.00	0.00	0.00	Toluene	0.0190	92.1	0.00	0.00	0.00	Ethylbenzene	0.0000	106.2	0.00	0.00	0.00	2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00	Xylenes	0.0110	106.2	0.00	0.00	0.00	n-Hexane	0.1460	86.2	0.00	0.00	0.00	Nitrogen	0.0940	28.0	0.00	0.00	0.00	Carbon Dioxide	2.5280	44.0	0.00	0.00	0.00	Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00							VOC Subtotal	2.7600	1492.8	0.00	0.00	0.00	HAPS Subtotal	0.2030	546.9	0.00	0.00	0.00	Total	100.1460	1645.0	0.00	0.00	0.00
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Flare Combustion GHG emissions:					
	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year	
C1	88.97	0.00	0.00	0.00	
C2	5.79	0.00	0.00	0.00	
C3	1.37	0.00	0.00	0.00	
C4	0.63	0.00	0.00	0.00	
C5+	0.76	0.00	0.00	0.00	
CO₂ Total Emissions:				0.00	Tons/Year
N₂O Emissions:				0.00E+00	Tons/Year
Flare Combustion Emissions:					
		Fuel Heating Value:	1028.00	btu/scf	
		lbs/mmBTU	lbs/hour	Tons/event	
	CO	0.00	0.00	0.00	AP-42 CH13.5-1
	NOx	0.000	0.00	0.00	AP-42 CH13.5-1
	SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Production Phase

Production Equipment Fugitive Component Emissions

Assumptions:

Components Counts:

	Fugitive Components				
Component *	Valves	Connectors	OE Lines	PR Valves	
Count	59	193	8	3	0
Emissions Factor (scf/hr) ^b	0.121	0.017	0.031	0.193	0.000

* Fugitive component counts for natural gas wells from Subpart W, Table W-1B

* Fugitive component counts for oil wells from Subpart W, Table W-1C

Annual Equipment Run Time: 8760 Hours/Year 379.49 Scf/lb-mol

Component	Mole % ^a	Mole Weight lb/lb-mol	Emissions Scf/Year ^b	Emissions lbs/Year	Emissions Tons/Year
Methane	88.9720	16.0	87,658.5	3,705.8	1.85
Ethane	5.7920	30.1	5,706.5	452.2	0.23
Propane	1.3650	44.1	1,344.8	156.3	0.08
i-Butane	0.3700	58.1	364.5	55.8	0.03
n-Butane	0.2610	58.1	257.1	39.4	0.02
i-Pentane	0.1550	72.2	152.7	29.0	0.01
n-Pentane	0.1020	72.2	100.5	19.1	0.01
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	143.8	32.7	0.02
Heptanes	0.0930	100.2	91.6	24.2	0.01
Octanes	0.0440	114.2	43.4	13.0	0.01
Nonanes	0.0160	128.3	15.8	5.3	0.00
Decanes +	0.0050	142.3	4.9	1.8	0.00
Benzene	0.0270	78.1	26.6	5.5	0.00
Toluene	0.0190	92.1	18.7	4.5	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	10.8	3.0	0.00
n-Hexane	0.1460	86.2	143.8	32.7	0.02
Nitrogen	0.0940	28.0	92.6	6.8	0.00
Carbon Dioxide	2.5280	44.0	2,490.7	288.8	0.14
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600			422.43	0.21
HAPS Subtotal	0.2030			45.72	0.02
Total	100.1460			4876.06	2.44

Calculation

$$\text{lb/hr} = (\text{Mol \%} * \text{SumSCF/yr}) / \text{scf/lb-mol}$$

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b Fugitive emission factors from Subpart W, Table W-1A

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Production Phase
Process Heater Emissions

Wellsite Heater Inventory:

	Heating Value (Mbtu/hr)	Fuel Consumption (MMscf/yr)	
Separator Heater	750	6.44	* Heater treater size based on industry standard

Annual Run Time:	8760	Hours/Year
Fuel Gas Heat Value:	1,020	Btu/scf (Standard heating value from AP-42)

Equations:

$$\text{Fuel Consumption (MMscf/yr)} = \frac{\text{Heater Size (MBtu/hr)} * 1,000 \text{ (Btu/MBtu)} * \text{Hours of Operation (hrs/yr)}}{\text{Fuel Heat Value (Btu/scf)} * 1,000,000 \text{ (scf/MMscf)}}$$

$$\text{NOx/CO/TOC Emissions (tons/yr)} = \frac{\text{AP-42 E.Factor (lbs/MMscf)} * \text{Fuel Consumption (MMscf/yr)} * \text{Fuel heating Value (Btu/scf)}}{2,000 \text{ (lbs/ton)} * 1,020 \text{ (Btu/scf - Standard Fuel Heating Value)}}$$

	Emission Factor (lb/MMscf)	Separator Heater Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year) ^e
<i>Criteria Pollutants & VOC</i>						
NOx ^a	100	0.3221	0.0000	0.0000	0.0000	0.3221
CO ^a	84.0	0.2705	0.0000	0.0000	0.0000	0.2705
VOC	5.5	0.0177	0.0000	0.0000	0.0000	0.0177
SO ₂ ^b	0.00	0.0000	0.0000	0.0000	0.0000	0.0000
TSP ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
PM ₁₀ ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
PM _{2.5} ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
<i>Hazardous Air Pollutants</i>						
Benzene ^d	2.10E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Toluene ^d	3.40E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Hexane ^d	1.80	0.0058	0.0000	0.0000	0.0000	0.0058
Formaldehyde ^d	7.50E-02	0.0002	0.0000	0.0000	0.0000	0.0002
<i>Greenhouse Gases</i>						
CO ₂ ^f	120,162	386.9918	0.0000	0.0000	0.0000	386.9918
CH ₄ ^f	2.27	0.0073	0.0000	0.0000	0.0000	0.0073
N ₂ O ^f	0.23	0.0007	0.0000	0.0000	0.0000	0.0007

a AP-42 Table 1.4-1, Emission Factors for Natural Gas Combustion, 7/98

b Assumes produced gas contains no sulfur

c AP-42 Table 1.4-2, Emission Factors for Natural Gas Combustion, 7/98 (All Particulates are PM_{1.0})

d AP-42 Table 1.4-3, Emission Factors for Organic Compounds from Natural Gas Combustion, 7/98

e Assumes maximum development scenario

f Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.

Kleinfelder, Inc. Wellsite Emissions			Base Location: Uinta/Piceance Basin Well Type: Natural Gas			
Production Phase						
Atmospheric Oil Tank Flashing Emissions						
Assumptions:						
Production Estimate:		10	barrels/day			
Production Days:		365	Days/Year			
Flasing Gas-to-Oil Ratio:		100	Scf/bbl	379.49 Scf/lb-mol		
Control Efficiency:		95	Percent (%)			
Flashing Gas Composition:						
Component	Mole %	Mole Weight (lb/lb-mol)	Emissions (Uncontrolled) Scf/Year	Emissions (Uncontrolled) lbs/Year	Emissions (Uncontrolled) Tons/Year	Emissions (Controlled) Tons/Year
Methane	44.8625	16.043	163748.125	6922.4780	3.4612	0.1731
Ethane	15.2687	30.07	55730.755	4415.9894	2.2080	0.1104
Propane	20.0892	44.097	73325.58	8520.4830	4.2602	0.2130
i-Butane	4.7308	58.123	17267.42	2644.6922	1.3223	0.0661
n-Butane	7.4972	58.123	27364.78	4191.2122	2.0956	0.1048
i-Pentane	2.2617	72.150	8255.205	1569.5092	0.7848	0.0392
n-Pentane	1.7732	72.150	6472.18	1230.5141	0.6153	0.0308
Other Pentanes	0.0000	70.100	0	0.0000	0.0000	0.0000
Hexanes	0.6780	86.177	2474.7	561.9706	0.2810	0.0140
Heptanes	0.6823	100.204	2490.395	657.5866	0.3288	0.0164
Octanes	0.1688	114.231	616.12	185.4594	0.0927	0.0046
Nonanes	0.0186	128.258	67.89	22.9451	0.0115	0.0006
Decanes +	0.0081	142.285	29.565	11.0850	0.0055	0.0003
Benzene	0.1117	78.120	407.705	83.9282	0.0420	0.0021
Toluene	0.0525	92.130	191.625	46.5214	0.0233	0.0012
Ethylbenzene	0.0013	106.160	4.745	1.3274	0.0007	0.0000
2,2,4 Trimethylpentane	0.0000	78.120	0	0.0000	0.0000	0.0000
Xylenes	0.0077	106.160	28.105	7.8622	0.0039	0.0002
n-Hexane	0.5041	86.177	1839.965	417.8309	0.2089	0.0104
Nitrogen	0.1776	28.013	648.24	47.8515	0.0239	0.0012
Carbon Dioxide	1.1062	44.010	4037.63	468.2497	0.2341	0.0117
Hydrogen Sulfide	0.0000	34.080	0	0.0000	0.0000	0.0000
VOC Subtotal	38.59				10.08	0.50
HAPS Subtotal	0.68				0.28	0.01
Total	100.0002				16.0037	0.8002
Calculation:						
Scf/yr = (Mol% * scf/bbl * bbl/day * days/yr) / 100						
lb/yr = (scf/yr * mol wt.) / scf/lb-mol						
* Production and gas to oil ratio based on basin specific differences. Please see "Gas Stream Molar Ratios" tab and report for additional information.						

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas									
Production Phase										
Wellsite Produced Water Tanks Venting										
Assumptions: Average Estimated Water Production: 4000 Barrels Per Year Number of Water Tanks: 1 Tanks VOC Emissions Factor: 0.2620 lbs/bbl n-Hexane Emission Factor: 0.0220 lbs/bbl Benzene Emission Factor: 0.0070 lbs/bbl Calculations: <table border="1"><tr><td>VOC Emissions:</td><td>0.524</td><td>Tons/Year</td></tr><tr><td>Hexane Emissions:</td><td>0.044</td><td>Tons/Year</td></tr><tr><td>Benzene Emissions:</td><td>0.014</td><td>Tons/Year</td></tr></table> <ul style="list-style-type: none">* Production conservatively based on estimated industry single well average* Emission factors based on only known lb/bbl factor, which was developed by the Colorado Department of Health and Environment (PS Memo 09-02).		VOC Emissions:	0.524	Tons/Year	Hexane Emissions:	0.044	Tons/Year	Benzene Emissions:	0.014	Tons/Year
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Hexane Emissions:	0.044	Tons/Year								
Benzene Emissions:	0.014	Tons/Year								

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Uinta/Piceance Basin
Well Type: Natural Gas

Production Phase
Truck Loading Emissions

AP - 42, Chapter 5.2

$$L_L = 12.46 \times S \times P \times M / T$$

L_L = Loading Loss Emission Factor (lbs VOC/1000 gal loaded)
S = Saturation Factor
P = True Vapor Pressure of the Loaded Liquid (psia)
M = Vapor Molecular Weight of the Loaded Liquid (lbs/lbmol)
T = Temperature of Loaded Liquid (°R)

$$\text{VOC Emissions (tpy)} = \frac{L_L (\text{lbs VOC}/1000 \text{ gal}) \times 42 \text{ gal/bbl} \times 365 \text{ days/year} \times \text{production (bbl/day)}}{1000 \text{ gal} \times 2000 \text{ lbs/ton}}$$

S ¹	P (psia) ²	M (lb/lbmol) ³	T (°F) ⁴	T (°R)	L _L (lb/1000 gal)	Production (bbl/day)	VOC (tpy)
0.6	4.20	66.00	50.00	509.67	4.07	10.0	0.31

Notes:

1. Saturation factor from AP-42, Table 5.2-1 (Submerged loading: dedicated normal service)
2. True vapor pressure is estimated from AP-42, Table 7.1-2 assuming an average daily temperature of either 40 or 50 deg F and an RVP of 10.0.
3. Molecular weight liquid vapor is estimated from AP-42, Table 7.1-2 assuming an RVP of 10.0.
4. Temperature based on the annual average temperature for basin location (either 40 or 50 degrees F based on options provided in AP-42 Table 7.1-2)

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																																																																																															
Production Phase Pumpjack Unit Emissions																																																																																																
<p>Assumptions:</p> <p style="text-align: center;">*Pumpjack engines only included at oil wells*</p> <div style="display: flex; justify-content: space-between; margin-top: 10px;"> <div style="width: 45%;"> Pumpjack Horsepower Rating: Load Factor: Brake Specific Fuel Consumption: Annual Operation: </div> <div style="width: 10%; text-align: center;"> 0.0 0.54 0 8,760 </div> <div style="width: 45%;"> Horsepower Btu/hp-hr Hours/Year </div> </div> <p style="margin-top: 10px;">Equations:</p> <div style="display: flex; justify-content: space-between; margin-top: 10px;"> <div style="width: 35%;">Emissions (lbs/hr) =</div> <div style="width: 60%; text-align: center;"> $\frac{\text{Emission Factor (g/hp-hr)} * \text{Power (hp)}}{453.6 \text{ g/lb}}$ </div> </div>																																																																																																
<table border="1" style="width: 100%; border-collapse: collapse; text-align: center;"> <thead> <tr> <th style="width: 25%;">Pollutant</th> <th style="width: 15%;">Emission Factor ^a (lb/MMBtu)</th> <th style="width: 15%;">Emission Factor ^a (g/hp-hr)</th> <th style="width: 15%;">Emissions (lb/hr)</th> <th style="width: 30%;">Emissions (Tons/Year)</th> </tr> </thead> <tbody> <tr> <td colspan="5" style="text-align: left;"><i>Criteria Pollutants & VOC</i></td> </tr> <tr> <td>NOx</td> <td></td> <td>2.80</td> <td>0.00</td> <td>0.0000</td> </tr> <tr> <td>CO</td> <td></td> <td>4.80</td> <td>0.00</td> <td>0.0000</td> </tr> <tr> <td>VOC</td> <td>0.12</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td>PM₁₀ ^b</td> <td>4.83E-02</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>PM_{2.5} ^b</td> <td>4.83E-02</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>SO₂</td> <td>5.88E-04</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td colspan="5" style="text-align: left;"><i>Hazardous Air Pollutants</i></td> </tr> <tr> <td>Benzene</td> <td>1.94E-03</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Toluene</td> <td>9.63E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Ethylbenzene</td> <td>1.08E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Xylenes</td> <td>2.68E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Formaldehyde</td> <td>5.52E-02</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td>n-Hexane</td> <td>4.45E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td colspan="5" style="text-align: left;"><i>Greenhouse Gases</i></td> </tr> <tr> <td>CO₂ ^c</td> <td>117</td> <td>-</td> <td>0.00</td> <td>0</td> </tr> <tr> <td>CH₄</td> <td>0.002</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td>N₂O</td> <td>0.0002</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> </tbody> </table>		Pollutant	Emission Factor ^a (lb/MMBtu)	Emission Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	<i>Criteria Pollutants & VOC</i>					NOx		2.80	0.00	0.0000	CO		4.80	0.00	0.0000	VOC	0.12	-	0.0000	0.0000	PM₁₀ ^b	4.83E-02	-	0.00E+00	0.00E+00	PM_{2.5} ^b	4.83E-02	-	0.00E+00	0.00E+00	SO₂	5.88E-04	-	0.0000	0.0000	<i>Hazardous Air Pollutants</i>					Benzene	1.94E-03	-	0.00E+00	0.00E+00	Toluene	9.63E-04	-	0.00E+00	0.00E+00	Ethylbenzene	1.08E-04	-	0.00E+00	0.00E+00	Xylenes	2.68E-04	-	0.00E+00	0.00E+00	Formaldehyde	5.52E-02	-	0.0000	0.0000	n-Hexane	4.45E-04	-	0.00E+00	0.00E+00	<i>Greenhouse Gases</i>					CO₂ ^c	117	-	0.00	0	CH₄	0.002	-	0.0000	0.0000	N₂O	0.0002	-	0.0000	0.0000
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<p>a AP-42 Table 3.2-3 Uncontrolled Emission Factors for 4-Stroke Rich-Burn Engines, 7/00; and Subpart JJJJ for NOX and CO emission rates.</p> <p>b PM = sum of PM filterable and PM condensable</p> <p>c Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.</p> <p style="margin-top: 10px;">- Network website for the 1999 National-Scale Air Toxics Assessment at http://www.epa.gov/ttn/atw/nata1999/nsata99.html</p>																																																																																																

Kleinfelder, Inc. Wellsite Emissions	Base Location: Uinta/Piceance Basin Well Type: Natural Gas																								
Production Phase																									
Wellsite Dehydrator Emissions																									
<p>Assumptions:</p> <p>Number of Dehy Units: 0 Units</p> <p>Calculations:</p> <p>Calculations and specifications derived from Pinedale Anticline Final SEIS GRI-GLYCalc 4.0 operated with: 4 MMSCFD, 0.32 gpm glycol flow, average representative gas analysis, and 95% control efficiency</p> <p>Emissions:</p> <table border="1" data-bbox="553 987 1062 1478"> <thead> <tr> <th>Species</th><th>Total Project Emissions (tons/year)</th></tr> </thead> <tbody> <tr> <td>Total VOC</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Hazardous Air Pollutants</i></td></tr> <tr> <td>Benzene</td><td>0.000</td></tr> <tr> <td>Toluene</td><td>0.000</td></tr> <tr> <td>Ethylbenzene</td><td>0.000</td></tr> <tr> <td>Xylenes</td><td>0.000</td></tr> <tr> <td>n-Hexane</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Greenhouse Gases</i></td></tr> <tr> <td>CO₂</td><td>0.000</td></tr> <tr> <td>CH₄^a</td><td>0.000</td></tr> <tr> <td>N₂O</td><td>0.000</td></tr> </tbody> </table> <p>Note, no greenhouse gas emissions included for dehydrator in Pinedale EIS</p>		Species	Total Project Emissions (tons/year)	Total VOC	0.000	<i>Hazardous Air Pollutants</i>		Benzene	0.000	Toluene	0.000	Ethylbenzene	0.000	Xylenes	0.000	n-Hexane	0.000	<i>Greenhouse Gases</i>		CO₂	0.000	CH₄^a	0.000	N₂O	0.000
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Average Round Trip Distance:		40.0	Miles/Trip Average																																																																			
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Water Trucks		40	Trips/Location		Total Trips: 42 Trips																																																																	
* Miles and number of trips based on research and industry knowledge; please see report for additional information.																																																																						
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<table><tr><th rowspan="2">Construction Vehicles</th><th colspan="2">Heavy Haul Trucks</th><th colspan="2">Light Duty Pickups</th><th>Total</th></tr><tr><th>E. Factor ^a (lb/mile)</th><th>Emissions (Tons/Location)</th><th>E. Factor ^b (lb/mile)</th><th>Emissions (Tons/Location)</th><th>Emissions (Tons/Location)</th></tr><tr><td>NOx</td><td>7.44E-02</td><td>6.25E-02</td><td>7.39E-03</td><td>7.39E-03</td><td>6.99E-02</td></tr><tr><td>CO</td><td>1.98E-02</td><td>1.66E-02</td><td>7.26E-02</td><td>7.26E-02</td><td>8.92E-02</td></tr><tr><td>VOC</td><td>3.16E-03</td><td>2.65E-03</td><td>3.54E-03</td><td>3.54E-03</td><td>6.19E-03</td></tr><tr><td>SO2</td><td>4.57E-05</td><td>3.84E-05</td><td>2.83E-05</td><td>2.83E-05</td><td>6.67E-05</td></tr><tr><td>PM10</td><td>4.22E-03</td><td>3.54E-03</td><td>1.94E-04</td><td>1.94E-04</td><td>3.74E-03</td></tr><tr><td>PM2.5</td><td>4.09E-03</td><td>3.44E-03</td><td>1.79E-04</td><td>1.79E-04</td><td>3.61E-03</td></tr><tr><td>CO2</td><td>1.88E+00</td><td>1.58E+00</td><td>1.13E+00</td><td>1.13E+00</td><td>2.70E+00</td></tr><tr><td>CH4</td><td>7.61E-05</td><td>6.39E-05</td><td>4.56E-05</td><td>4.56E-05</td><td>1.10E-04</td></tr><tr><td>N2O</td><td>1.52E-05</td><td>1.28E-05</td><td>9.13E-06</td><td>9.13E-06</td><td>2.19E-05</td></tr></table>						Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)	NOx	7.44E-02	6.25E-02	7.39E-03	7.39E-03	6.99E-02	CO	1.98E-02	1.66E-02	7.26E-02	7.26E-02	8.92E-02	VOC	3.16E-03	2.65E-03	3.54E-03	3.54E-03	6.19E-03	SO2	4.57E-05	3.84E-05	2.83E-05	2.83E-05	6.67E-05	PM10	4.22E-03	3.54E-03	1.94E-04	1.94E-04	3.74E-03	PM2.5	4.09E-03	3.44E-03	1.79E-04	1.79E-04	3.61E-03	CO2	1.88E+00	1.58E+00	1.13E+00	1.13E+00	2.70E+00	CH4	7.61E-05	6.39E-05	4.56E-05	4.56E-05	1.10E-04	N2O	1.52E-05	1.28E-05	9.13E-06	9.13E-06	2.19E-05
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a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.																																																																						
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c Assumes maximum development scenario																																																																						

Kleinfelder, Inc. Wellsite Emissions				Base Location: Uinta/Piceance Basin Well Type: Natural Gas			
Production Phase Pneumatic Device Emissions							
Wellsite Pneumatic Inventory:							
Devices:		Dump Valve Pneumatic Controller	Classification Intermittent Bleed Low Bleed	Quantity 2 1 0	Emission Factor (Scf/hr/unit) 13.50 1.39 0.00		
Pumps:		Chemical Pump Sandpiper	Pneumatic Pump Pneumatic Pump	1 1	13.30		
Annual Equipment Run Time:		8760	Hours/Year	379.49 Scf/lb-mol			
Pneumatic Device Control: ^a		0	Percent				
				* Low bleed and intermittent bleed emission factors (scf/hr) based on Subpart W, Table W-1A			
				* Quantity of devices based on typical industry values			
Component	Mole %	Mole Weight lb/lb-mol	Dump Valve Tons/Year	Pneumatic Controller Tons/Year	(None) Tons/Year	Pneumatic Pumps Tons/Year	Total Tons/Year
Methane	88.9720	16.0	4.448	0.229	0.000	4.382	9.059
Ethane	5.7920	30.1	0.543	0.028	0.000	0.535	1.105
Propane	1.3650	44.1	0.188	0.010	0.000	0.185	0.382
i-Butane	0.3700	58.1	0.067	0.003	0.000	0.066	0.136
n-Butane	0.2610	58.1	0.047	0.002	0.000	0.047	0.096
i-Pentane	0.1550	72.2	0.035	0.002	0.000	0.034	0.071
n-Pentane	0.1020	72.2	0.023	0.001	0.000	0.023	0.047
Other Pentanes	0.0000	70.1	0.000	0.000	0.000	0.000	0.000
Hexanes	0.1460	86.2	0.039	0.002	0.000	0.039	0.080
Heptanes	0.0930	100.2	0.029	0.001	0.000	0.029	0.059
Octanes	0.0440	114.2	0.016	0.001	0.000	0.015	0.032
Nonanes	0.0160	128.3	0.006	0.000	0.000	0.006	0.013
Decanes +	0.0050	142.3	0.002	0.000	0.000	0.002	0.005
Benzene	0.0270	78.1	0.007	0.000	0.000	0.006	0.013
Toluene	0.0190	92.1	0.005	0.000	0.000	0.005	0.011
Ethylbenzene	0.0000	106.2	0.000	0.000	0.000	0.000	0.000
2,2,4 Trimethylpentane	0.0000	78.1	0.000	0.000	0.000	0.000	0.000
Xylenes	0.0110	106.2	0.004	0.000	0.000	0.004	0.007
n-Hexane	0.1460	86.2	0.039	0.002	0.000	0.039	0.080
Nitrogen	0.0940	28.0	0.008	0.000	0.000	0.008	0.017
Carbon Dioxide	2.5280	44.0	0.347	0.018	0.000	0.342	0.706
Hydrogen Sulfide	0.0000	34.1	0.000	0.000	0.000	0.000	0.000
VOC Subtotal	2.8	1492.8	0.51	0.03	0.00	0.50	1.03
HAPS Subtotal	0.2	546.9	0.05	0.00	0.00	0.05	0.11
Total	100.1	1645.0	5.85	0.30	0.00	5.77	11.92

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b 98% control input is a result of the Wyoming Department of Environment Quality requirement, and only pertains to the Upper Green River Basin.

APPENDIX C

EMISSION INVENTORY FOR THE UPPER GREEN RIVER BASIN GAS WELL

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Location Selection:

Geography:

Well Type:

Upper Green River Basin Natural Gas

- Choose geography/basin, and well type will automatically fill
- < Choose Uinta/Piceance Basin for deep gas wells with little condensate
- < Choose Upper Green River Basin for deep gas wells with dehydrators and higher condensate
- < Choose San Juan Basin for shallow gas wells with little to no condensate
- < Choose Williston Basin for deep oil wells with high gas
- < Choose Denver Basin for shallow oil wells with low gas

If the user wants to change any specifications, do so within the "Constants and References" tab, as all other tabs connect to it.

Pollutant:	Total Emissions (Tons per Year)								
	NO _x	CO	VOC	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O
Construction Phase:	0.47	0.29	0.04	0.0001	1.94	0.06	33.84	0.001	0.0003
Development Phase:	13.24	2.86	0.68	0.0002	4.70	0.44	1900.27	1.11	0.0498
Operation Phase:	0.86	0.75	4.43	0.0001	0.08	0.26	947.96	12.99	0.0018
Total:	14.57	3.90	5.16	0.0004	6.72	0.76	2882.07	14.10	0.0519

Pollutant:	Total Emissions (Tons per Year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	HAPs
Construction Phase:	0.00	0.00	0.00	0.00	0.00	0.00
Development Phase:	1.36	0.95	0.0000	0.55	7.31	10.18
Operation Phase:	0.11	0.22	0.01029	0.169	0.19	0.70
Total:	1.47	1.17	0.01029	0.72	7.50	10.87

CO ₂ equivalent (Global Warming Potential)	
Total TPY:	3194.19
CO ₂ equivalent conversions:	
CO ₂ 1.00	
CH ₄ 21.00	
N ₂ O 310.00	

H ₂ S Emissions	
Total TPY:	0.00

* If H₂S in gas, input value in "Gas Stream Molar Ratios" tab, and potential emissions will calculate here. Current assumption is no H₂S in gas stream.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase

Road Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	4	Days/Location	(Typical Value)
	48.0	Dozer Hours/Location	(Typical Value)
	48.0	Backhoe Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅ (AP-42 Table 11.9-1, 7/98)		
PM _{2.5} Multiplier:	0.105 * TSP (AP-42 Table 11.9-1, 7/98)		

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98 & 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0473	1.97	0.0473	0.0946
PM₁₅	0.50	0.0120	0.50	0.0120	0.0241
PM₁₀	0.38	0.0090	0.38	0.0090	0.0181
PM_{2.5}	0.21	0.0050	0.05	0.0013	0.0062

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase
Road Grader Particulate Matter

Assumptions:

Grading Length:	6.00	miles	(Typical Value)
Construction Schedule:	3	Days/Location	(Typical Value)
	12	Hours/Day	(Typical Value)
	36	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	
Average Grader Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 16.12 lbs TSP/Location

Emissions = 7.71 lbs PM₁₅/Location

Grader Construction Emissions			
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	16.12	0.45	8.06E-03
PM₁₅	7.71	0.21	3.86E-03
PM₁₀	4.63	0.13	2.31E-03
PM_{2.5}	0.50	0.01	2.50E-04

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase

Well Pad Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7	Days/Location		(Typical Value)
	10	Hours/Day		(Typical Value)
	70	Hours/Location	(Dozer)	(Typical Value)
	70	Hours/Location	(Back Hoe)	(Typical Value)
Watering Control Efficiency:	50	Percent (%)		(Typical Value)
Soil Moisture Content:	7.9	Percent (%)		AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)		AP-42 Table 11.9-3, 7/98

PM₁₀ Multiplier: 0.75 * PM₁₅ (AP-42 Table 11.9-1, 7/98)

PM_{2.5} Multiplier: 0.105 * TSP (AP-42 Table 11.9-1, 7/98)

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

Emissions (TSP lbs/hr) = $5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs/hr) = $1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase
Well Pad Grader Particulate Matter

Assumptions:

Construction Schedule:	4.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	40	Hours/Location	(Typical Value)
Watering Control Efficiency	50	Percent (%)	(Typical Value)
Average Grader Speed	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
Distance Graded	2.84	Miles/Location	(Typical Value)
PM ₁₀ Multiplier	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 7.63 lbs TSP/well pad

Emissions = 3.65 lbs PM₁₅/well pad

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	7.63	0.19	0.0038
PM₁₅	3.65	0.09	0.0018
PM₁₀	2.19	0.05	0.0011
PM_{2.5}	0.24	0.01	0.0001

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase

Pipeline Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs/hr) = $5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs/hr) = $1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase

Pipeline Grader Particulate Matter

Assumptions:

Distance Graded:	12.50	Miles/Location	(Typical Value)
Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Mean Vehicle Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15}\text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 33.58 lbs TSP/well

Emissions = 16.07 lbs PM₁₅/well

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	33.58	0.48	0.0168
PM₁₅	16.07	0.23	0.0080
PM₁₀	9.64	0.14	0.0048
PM_{2.5}	1.04	0.01	0.0005

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Heavy Diesel Truck Trips:

Road Construction:	7	Trips			
Well Pad Construction:	8	Trips	Total Trips:	21	Trips
Pipeline Construction:	6	Trips			

Light Duty Pickup Truck Trips:

Road Construction:	16	Trips			
Well Pad Construction:	28	Trips	Total Trips:	100	Trips
Pipeline Construction:	56	Trips			

* All assumptions above are based on typical industry values

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a	Emissions	E. Factor ^b	Emissions	Emissions
	(lb/mile)	(Tons/Location)	(lb/mile)	(Tons/Location)	(Tons/Location)
NOx	7.44E-02	3.12E-02	7.39E-03	1.48E-02	4.60E-02
CO	1.98E-02	8.32E-03	7.26E-02	1.45E-01	1.54E-01
VOC	3.16E-03	1.33E-03	3.54E-03	7.08E-03	8.41E-03
SO2	4.57E-05	1.92E-05	2.83E-05	5.66E-05	7.58E-05
PM10	4.22E-03	1.77E-03	1.94E-04	3.88E-04	2.16E-03
PM2.5	4.09E-03	1.72E-03	1.79E-04	3.58E-04	2.08E-03
CO2	1.88	0.79	1.13	2.25	3.04
CH4	7.61E-05	3.19E-05	4.56E-05	9.13E-05	1.23E-04
N2O	1.52E-05	6.39E-06	9.13E-06	1.83E-05	2.46E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Construction Phase

Construction Heavy Equipment Tailpipe Emissions

Assumptions:

Fuel and Engine:

Brake Specific Fuel Consumption, Avg. (BSFC) 8250 btu/hp-hr (Typical Value)
Diesel Higher Heating Value (HHV) 0.138 mmBtu/Gallon (Typical Value)

Trackhoe:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 100 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Tractors/Loaders/Backhoes)

Dozer:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 140 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Crawler Tractor/Dozers)

Grader:

Working Hours 130 Total Hours (Typical Value)
Rated Horsepower 250 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Graders)

Total Horsepower Hours: 45795.8 Hp-hrs (Sum of all horsepower above)
Total Fuel Usage: 2737.79 Gallons Diesel Fuel

Equations:

Total Fuel Usage: (btu-hp-hr * hp-hrs) / Mmbtu-gal) / 1,000,000
Emissions (tons/year/pad) = $\frac{\text{Emission Factor (g/mile)} * \text{Trip Distance (miles)} * \text{Load Factor}}{453.6 \text{ (g/lb)} * 2000 \text{ (lb/tons)}}$

Heavy Const. Vehicles	Backhoe			Dozer			Grader		
	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
NOx	8.38	1.09E+00	1.02E-01	8.38	1.53E+00	1.43E-01	8.38	2.72E+00	1.77E-01
CO	2.7	3.51E-01	3.30E-02	2.7	4.92E-01	4.62E-02	2.7	8.78E-01	5.71E-02
VOC ^b	0.68	8.84E-02	8.31E-03	0.68	1.24E-01	1.16E-02	0.68	2.21E-01	1.44E-02
PM₁₀	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03
PM_{2.5}	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03

Heavy Const. Vehicles	Total Emissions ^c (tons/yr)
NOx	0.42
CO	0.14
VOC	0.03
PM₁₀	0.02
PM_{2.5}	0.02

Greenhouse Gas Emissions:

	Diesel EF kg/mmbtu	Emissions lbs	Emissions Tons
CO ₂	73.96	61604.19	30.80
CH ₄	0.003	2.50	0.0012
N ₂ O	0.0006	0.50	0.0002

a From Table A-4 of Exhaust and Crankcase Emission Factors for NONROAD Engine Modeling - Compression Ignition, EPA-420-R-10-018, July 2010.

b Emission Factor represents total Hydrocarbon Emissions

c Converted from emission factor for Distillate Fuel Oil #2 (diesel) as listed in Table C-1 to Subpart C of Part 98 - Default Emission Factors and High Heat Values for Various Types of Fuel.

Listed Factor:

73.96 kg CO₂/mmBtu
393 hp-hr = mmBtu
188.2 g CO₂/hp-hr

Kleinfelder, Inc. Wellsite Emissions		Base Location: Upper Green River Basin Well Type: Natural Gas													
Construction Phase															
Wind Erosion Fugitive Dust															
Assumptions:															
Threshold Friction Velocity (U _f)	1.02 1.33	m/s (2.28 mph) for well pads (AP-42 Table 13.2.5-2 Overburden - Western Surface Coal Mine) m/s (2.97 mph) for roads (AP-42 Table 13.2.5-2 Roadbed material)													
Initial Disturbance Area															
Total Access Road/ROW Area Per Location:	976,800	Square Meters	(Typical Value)												
Total Well Pad Area Disturbed Per Location:	50,000	Square Meters	(Typical Value)												
Total Area Disturbed Per Location:	1,026,800	Square Meters	(Typical Value)												
Exposed Surface Type	Flat														
Meteorological Data	2002 Grand Junction (obtained from NCDC website)														
Fastest Mile Wind Speed:	45	miles/hour	(Typical Value)												
Fastest Mile Wind Speed (U ₁₀ ⁺)	20.12	meters/sec (45 mph) reported as fastest 2-minute wind speed for Grand Junction (2002)													
Number soil of disturbances	1.00	for well pads (Assumption, disturbance at construction and reclamation) constant for dirt roads													
Equations (AP-42 13.2.5.2 Industrial Wind Erosion)															
Friction Velocity U* = 0.053 U ₁₀ ⁺															
Erosion Potential P (g/m ² /period) = 58*(U*-U _t [*]) ² + 25*(U*-U _t [*]) for U*>U _t [*] , P = 0 for U*< U _t [*]															
Emissions (tons/year) = Erosion Potential(g/m ² /period)*Disturbed Area(m ²)*Disturbances/year*(k)/(453.6 g/lb)/2000 lbs/ton/Develop Period															
<table><tr><th colspan="3">Particle Size Multiplier (k)</th></tr><tr><td>30 μm</td><td><10 μm</td><td><2.5 μm</td></tr><tr><td>1.0</td><td>0.5</td><td>0.075</td></tr></table>				Particle Size Multiplier (k)			30 μm	<10 μm	<2.5 μm	1.0	0.5	0.075			
Particle Size Multiplier (k)															
30 μm	<10 μm	<2.5 μm													
1.0	0.5	0.075													
<table><tr><th>Maxium U₁₀⁺ Wind Speed (m/s)</th><th>Maximum U* Friction Velocity m/s</th><th>Well U_t[*] Threshold Velocity^a m/s</th><th>Well Pad Erosion Potential g/m²</th><th>Road U_t[*] Threshold Velocity^a m/s</th><th>Road Erosion Potential g/m²</th></tr><tr><td>20.12</td><td>1.07</td><td>1.02</td><td>1.28</td><td>1.33</td><td>0.00</td></tr></table>				Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t [*] Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t [*] Threshold Velocity ^a m/s	Road Erosion Potential g/m ²	20.12	1.07	1.02	1.28	1.33	0.00
Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t [*] Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t [*] Threshold Velocity ^a m/s	Road Erosion Potential g/m ²										
20.12	1.07	1.02	1.28	1.33	0.00										
Wind Erosion Emissions															
<table><tr><th>Particulate Species</th><th>Well Pad (tons/year)</th><th>Roads/Pipelines (tons/year)</th></tr><tr><td>TSP</td><td>7.05E-02</td><td>0.00E+00</td></tr><tr><td>PM₁₀</td><td>3.52E-02</td><td>0.00E+00</td></tr><tr><td>PM_{2.5}</td><td>5.28E-03</td><td>0.00E+00</td></tr></table>				Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)	TSP	7.05E-02	0.00E+00	PM ₁₀	3.52E-02	0.00E+00	PM _{2.5}	5.28E-03	0.00E+00
Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)													
TSP	7.05E-02	0.00E+00													
PM ₁₀	3.52E-02	0.00E+00													
PM _{2.5}	5.28E-03	0.00E+00													

Kleinfelder, Inc.				Base Location: Upper Green River Basin					
Website Emissions				Well Type: Natural Gas					
Construction, Development, and Production Phase									
Construction, Development, and Operations Traffic Fugitive Dust Emissions									
Assumptions:									
				Round Trip Miles	40				
				Round Trip (Paved) Miles	16				
				Round Trip (Un-Paved) Miles	24				
				Precipitation Days (P)	55				
Unpaved Calculation AP-42, Chapter 13.2.2				$E (PM_{10}) / VMT = 1.5 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
November 2006				$E (PM_{2.5}) / VMT = 0.15 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
				Silt Content (S)	8.5		AP 42 13.2.2-1 Mean Silt Content Construction Sites		
Paved Calculation AP-42, Chapter 13.2.1				$E (PM_{10}) / VMT = 0.0022 * (sL)^{0.91} * (W)^{0.02} * (1-(P/(365*4)))$					
January 2011				$E (PM_{2.5}) / VMT = 0.00054 * (sL)^{0.91} * (W)^{0.02} * (1-(P/(365*4)))$					
				Silt Loading (sL)	0.6		AP-42 Table 13.2.1-2 baseline low volume roads		
Unpaved Calculations:									
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	3.00	1510.2	0.8	0.3	151.0	0.1
	Light Duty Pickup Trucks	5,000	100	0.86	2065.2	1.0	0.1	206.5	0.1
	Total:				3575.33	1.79		357.53	0.18
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	0.0572	19.2	0.0096	0.014	4.7	0.0024
	Light Duty Pickup Trucks	5,000	100	0.0034	5.4	0.0027	0.001	1.3	0.0007
	Total:				24.6	0.0		6.0	0.0
Unpaved Calculations:									
Development Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	84	0.86	1734.7	0.9	0.1	173.5	0.1
	Light Duty Haul Trucks	7,500	11	1.03	272.6	0.1	0.1	27.3	0.0
	Heavy Duty Haul Trucks	80,000	67	3.00	4818.2	2.4	0.3	481.8	0.2
	Water Trucks	70,000	24	2.82	1625.3	0.8	0.3	162.5	0.1
	Total:				8450.81	4.23		845.08	0.42
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips						
	Light Duty Pickup Trucks:	5000	84	0.00	4.5	0.0	0.0	1.1	0.0006
	Light Duty Haul Trucks	7500	11	0.01	0.9	0.0	0.0	0.2	0.0001
	Heavy Duty Haul Trucks	80000	67	0.06	61.3	0.0	0.0	15.1	0.0075
	Water Trucks	70,000	24	0.05	19.2	0.0	0.0	4.7	0.0024
	Total:				85.9	0.0		21.1	0.0
Unpaved Calculations:									
Production Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	50	0.86	1032.58	0.52	0.0860	103.26	0.0516
	Light Duty Haul Trucks	7,500	0	1.03	0.00	0.00	0.1033	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	3.00	143.83	0.07	0.2996	14.38	0.0072
	Water Trucks	70,000	40	2.82	2708.76	1.35	0.2822	270.88	0.1354
	Total:				3885.17	1.94		388.52	0.19
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks:	5,000	50	0.00	2.71	0.0014	0.0008	0.66	0.0003
	Light Duty Haul Trucks	7,500	0	0.01	0.00	0.0000	0.0013	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	0.06	1.83	0.0009	0.0140	0.45	0.0002
	Water Trucks	70,000	40	0.05	31.95	0.0160	0.0123	7.84	0.0039
	Total:				36.49	0.02		8.96	0.00
Annual Total					Unpaved Roads			Unpaved Roads	
					PM ₁₀ (tons)			PM _{2.5} (tons)	
					7.96			0.8	
					Paved Roads			Paved Roads	
				PM ₁₀ (tons)			PM _{2.5} (tons)		
				0.1			0.0		
				Total:			8.0 0.8		

Kleinfelder, Inc. Wellsite Emissions				Base Location: Upper Green River Basin Well Type: Natural Gas																																																																																																																																																																																			
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Total:				1,216,123	Hp-hrs																																																																																																																																																																																		
Fuel Usage:				72,703	Gallons of Diesel Total Fuel Usage: (btu/hp-hr * hp-hrs) * gal/btu																																																																																																																																																																																		
Greenhouse Gasses:																																																																																																																																																																																							
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Frontend loader	1008	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04																																																																																																																																																																													
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Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																																																																																																																																																																													
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1 Williston Basin: 2,100 from Jonah, Wyoming RMP																																																																																																																																																																																							
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Kleinfelder, Inc. Wellsite Emissions	Base Location: Upper Green River Basin Well Type: Natural Gas																																	
Development Phase																																		
Conductor Pipe Set Emissions																																		
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<table><tr><th>Parameter</th><th>Value</th></tr><tr><td>Days of Operation</td><td>2</td></tr><tr><td>Hours of Operation</td><td>24</td></tr><tr><td>Diesel Fuel Sulfur Content</td><td>0.000015</td></tr></table>	Parameter	Value	Days of Operation	2	Hours of Operation	24	Diesel Fuel Sulfur Content	0.000015	<table><tr><th>Parameter</th><th>Value</th><th>Units</th></tr><tr><td>BSFC (Avg.)</td><td>8250</td><td>btu/hp-hr</td></tr><tr><td>Diesel HHV</td><td>0.138</td><td>mmbtu/gal</td></tr></table> <div>(Typical Value)</div> <div>(Typical Value)</div>	Parameter	Value	Units	BSFC (Avg.)	8250	btu/hp-hr	Diesel HHV	0.138	mmbtu/gal																
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Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)																								
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Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																								
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<table><tr><td>Total:</td><td>0.00605</td><td>0.02069</td><td>0.00096</td><td>0.00093</td><td>0.00000</td><td>0.00164</td><td>0.00001</td><td>0.00000</td><td>0.00000</td><td>0.00000</td></tr></table>		Total:	0.00605	0.02069	0.00096	0.00093	0.00000	0.00164	0.00001	0.00000	0.00000	0.00000																						
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<div>Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton * Rig engine emission rates are based on a Tier II engine and rig generator emission rates are based on a Tier 0 engine. * All days, hours, and HP values above are based on typical industry values</div>																																		

Kleinfelder, Inc. Wellsite Emissions				Base Location: Upper Green River Basin Well Type: Natural Gas																																																																																																		
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Total: 1,500,576 Hp-hrs																																																																																																						
Fuel Usage: 89,708 Gallons of Diesel				Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu																																																																																																		

Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)
Frac Pump	148680	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Frac Pump	148680	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
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Frac Pump	148680	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Blenders	840	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Auxiliary Pump	336	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Auxiliary Pump	672	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Sand King	336	3.4900	8.3000	0.7220	0.7003	1.27E-05	0.9900	7.76E-04	2.81E-04	1.93E-04
Sand King	336	3.4900	8.3000	0.7220	0.7003	1.27E-05	0.9900	7.76E-04	2.81E-04	1.93E-04
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Sand King	336	3.4900	8.3000	0.7220	0.7003	1.27E-05	0.9900	7.76E-04	2.81E-04	1.93E-04
Generator	10584	3.4900	8.3000	0.7220	0.7003	1.27E-05	0.9900	7.76E-04	2.81E-04	1.93E-04

Engine	CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)
Frac Pump	0.12525	0.67195	0.02157	0.02092	2.08E-06	0.02681	0.00048	0.00017	0.00012
Frac Pump	0.12525	0.67195	0.02157	0.02092	2.08E-06	0.02681	0.00048	0.00017	0.00012
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Frac Pump	0.12525	0.67195	0.02157	0.02092	2.08E-06	0.02681	0.00048	0.00017	0.00012
Frac Pump	0.12525	0.67195	0.02157	0.02092	2.08E-06	0.02681	0.00048	0.00017	0.00012
Blenders	0.00078	0.00401	0.00012	0.00012	1.18E-08	0.00015	0.00000	0.00000	0.00000
Auxiliary Pump	0.00100	0.00310	0.00015	0.00014	4.70E-09	0.00025	0.00000	0.00000	0.00000
Auxiliary Pump	0.00200	0.00621	0.00030	0.00029	9.41E-09	0.00050	0.00000	0.00000	0.00000
Sand King	0.00129	0.00307	0.00027	0.00026	4.70E-09	0.00037	0.00000	0.00000	0.00000
Sand King	0.00129	0.00307	0.00027	0.00026	4.70E-09	0.00037	0.00000	0.00000	0.00000
Sand King	0.00129	0.00307	0.00027	0.00026	4.70E-09	0.00037	0.00000	0.00000	0.00000
Sand King	0.00129	0.00307	0.00027	0.00026	4.70E-09	0.00037	0.00000	0.00000	0.00000
Generator	0.04072	0.09683	0.00842	0.00817	1.48E-07	0.01155	0.00003	0.00001	0.00001

Total:	1.30213	6.84201	0.22574	0.21897	0.00002	0.28205	0.00480	0.00174	0.00119
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Emission Factors

- Frac pump emission factors based on Tier II engines (typical values)
- All other engine emission factors based on Tier 0 engines (typical values)

Calculations:

ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Development Phase

Hydraulic Fracturing Flowback Emissions

Assumptions:

Estimated Frac flowback Rate:	10,000	Scf/hr	
Combustion Efficiency:	95.00	Percent (%)	
Event Duration:	100.00	Hours	
	379.49	Scf/lb-mol	- Typical/Constant Conversion Value

* Venting duration based on research and industry knowledge; please see report for additional information.

* Venting control based on Subpart OOOO requirements of 95% minimum control.

Control efficiency can be deleted if applicable.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr

** Multiply above equation by 0.02 if including 98% control efficiency

Un-combusted Componet Emissions:

Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	444.86	18.81	0.94
Ethane	5.7920	30.1	28.96	2.29	0.11
Propane	1.3650	44.1	6.83	0.79	0.04
i-Butane	0.3700	58.1	1.85	0.28	0.01
n-Butane	0.2610	58.1	1.31	0.20	0.01
i-Pentane	0.1550	72.2	0.78	0.15	0.01
n-Pentane	0.1020	72.2	0.51	0.10	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.73	0.17	0.01
Heptanes	0.0930	100.2	0.47	0.12	0.01
Octanes	0.0440	114.2	0.22	0.07	0.00
Nonanes	0.0160	128.3	0.08	0.03	0.00
Decanes +	0.0050	142.3	0.03	0.01	0.00
Benzene	0.0270	78.1	0.14	0.03	0.00
Toluene	0.0190	92.1	0.10	0.02	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.06	0.02	0.00
n-Hexane	0.1460	86.2	0.73	0.17	0.01
Nitrogen	0.0940	28.0	9.40	0.69	0.03
Carbon Dioxide	2.5280	44.0	252.80	29.32	1.47
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600	1492.8	13.80	2.14	0.11
HAPS Subtotal	0.2030	546.9	1.02	0.23	0.01
Total	100.1460	1645.0	749.82	53.26	2.66

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	8452.34	980.23	49.01
C2	5.79	550.24	63.81	3.19
C3	1.37	129.68	15.04	0.75
C4	0.63	59.95	6.95	0.35
C5+	0.76	72.58	8.42	0.42

CO₂ Total Emissions:	53.72	Tons/Event
N₂O Emissions:	1.13E-04	Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.37	3.80	0.19	AP-42 CH13.5-1
NO _x	0.068	0.70	0.03	AP-42 CH13.5-1
SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions	Base Location: Upper Green River Basin Well Type: Natural Gas																																												
Development Phase																																													
Workover Cementing Emissions																																													
Assumptions:																																													
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<p>Total Horsepower: 1,500 (Typical Value)</p> <p>Total: 11,760 Hp-hrs</p> <p>Fuel Usage: 724 Gallons of Diesel Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)</p>	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>16298.85</td><td>8.15</td></tr><tr><td>CH4</td><td>0.003</td><td>0.66</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.13</td><td>0.00</td></tr></table>		Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	16298.85	8.15	CH4	0.003	0.66	0.00	N2O	0.0006	0.13	0.00																												
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<table><tr><th>Engine</th><th></th><th>CO (Tons/yr)</th><th>NO_x (Tons/yr)</th><th>PM₁₀ (Tons/yr)</th><th>PM_{2.5} (Tons/yr)</th><th>VOC (Tons/yr)</th><th>Benzene (Tons/yr)</th><th>Formaldehyde (Tons/yr)</th><th>Toulene (Tons/yr)</th><th>Xylenes (Tons/yr)</th></tr><tr><td>Coil Tubing Unit</td><td></td><td>0.00515</td><td>0.02649</td><td>0.00080</td><td>0.00078</td><td>0.00100</td><td>0.00002</td><td>0.00000</td><td>0.00001</td><td>0.00000</td></tr><tr><td>Circulation Pump</td><td></td><td>0.00421</td><td>0.02168</td><td>0.00066</td><td>0.00064</td><td>0.00082</td><td>0.00001</td><td>0.00000</td><td>0.00001</td><td>0.00000</td></tr><tr><td>Cement Pump Trucks</td><td></td><td>0.00500</td><td>0.01552</td><td>0.00074</td><td>0.00072</td><td>0.00126</td><td>0.00001</td><td>0.00000</td><td>0.00000</td><td>0.00000</td></tr></table>	Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Formaldehyde (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)	Coil Tubing Unit		0.00515	0.02649	0.00080	0.00078	0.00100	0.00002	0.00000	0.00001	0.00000	Circulation Pump		0.00421	0.02168	0.00066	0.00064	0.00082	0.00001	0.00000	0.00001	0.00000	Cement Pump Trucks		0.00500	0.01552	0.00074	0.00072	0.00126	0.00001	0.00000	0.00000	0.00000	
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Emission Factors - Engine emission factors based on Tier II engines (typical values)																																													
Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																													

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Development Phase
Well Venting During Workover Events

Assumptions:

Significant gas venting only occurs on natural gas wells.

Estimated Venting Rate: 5,000 Scf/Event (Typical Value)
Combustion Efficiency: 0.00 Percent (%)
Event Quantity: 1.00 Event - Assumed one event
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Vented quantity based on research and industry knowledge; please see report for additional information.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf-lb-mol)
** Multiply above equation by 0.02 if including 98% control efficiency

Component	Mole %	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Event
Methane	88.9720	16.0	4448.60	188.07	0.0940
Ethane	5.7920	30.1	289.60	22.95	0.0115
Propane	1.3650	44.1	68.25	7.93	0.0040
i-Butane	0.3700	58.1	18.50	2.83	0.0014
n-Butane	0.2610	58.1	13.05	2.00	0.0010
i-Pentane	0.1550	72.2	7.75	1.47	0.0007
n-Pentane	0.1020	72.2	5.10	0.97	0.0005
Other Pentanes	0.0000	70.1	0.00	0.00	0.0000
Hexanes	0.1460	86.2	7.30	1.66	0.0008
Heptanes	0.0930	100.2	4.65	1.23	0.0006
Octanes	0.0440	114.2	2.20	0.66	0.0003
Nonanes	0.0160	128.3	0.80	0.27	0.0001
Decanes +	0.0050	142.3	0.25	0.09	0.0000
Benzene	0.0270	78.1	1.35	0.28	0.0001
Toluene	0.0190	92.1	0.95	0.23	0.0001
Ethylbenzene	0.0000	106.2	0.00	0.00	0.0000
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.0000
Xylenes	0.0110	106.2	0.55	0.15	0.0001
n-Hexane	0.1460	86.2	7.30	1.66	0.0008
Nitrogen	0.0940	28.0	4.70	0.35	0.0002
Carbon Dioxide	2.5280	44.0	126.40	14.66	0.0073
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.0000

VOC Subtotal	2.7600	1492.8	138.00	21.44	0.0107
HAPS Subtotal	0.2030	546.9	10.15	2.32	0.0012
Total	100.1460	1645.0	5007.30	247.46	0.1237

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	0.00	0.00	0.00
C2	5.79	0.00	0.00	0.00
C3	1.37	0.00	0.00	0.00
C4	0.63	0.00	0.00	0.00
C5+	0.76	0.00	0.00	0.00

CO₂ Total Emissions: 0.00 Tons/Event
N₂O Emissions: 5.67E-07 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NOx	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.000	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions			Base Location: Upper Green River Basin Well Type: Natural Gas																																																																			
Development Phase																																																																						
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Average Round Trip Distance:		40.0	Miles/Trip Average																																																																			
Light Duty Pickup Trucks:		84	Trips/Location																																																																			
Light Duty Haul Trucks		11	Trips/Location		Total Trips: 95 Trips																																																																	
Heavy Duty Haul Trucks		67	Trips/Location																																																																			
Water Trucks		24	Trips/Location		Total Trips: 91 Trips																																																																	
* Miles and number of trips based on research and industry knowledge; please see report for additional information.																																																																						
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Kleinfelder, Inc. Wellsite Emissions	Base Location: Upper Green River Basin Well Type: Natural Gas																																																																																																																																																																																		
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<p style="text-align: center;">**Wellhead gas combustion only for Williston Basin wells, due to the regularity of of pit flares combusting all gas coming from the wellhead. If gas being captured, change scf/hr value or hours of event value.</p> <p>Assumptions:</p> <table style="width: 100%; margin-top: 10px;"> <tr> <td style="width: 35%;">Estimated Gas Flow Rate:</td> <td style="width: 15%;">0</td> <td style="width: 15%;">Scf/hr</td> <td style="width: 35%;"></td> </tr> <tr> <td>Combustion Efficiency:</td> <td>0.00</td> <td>Percent (%)</td> <td></td> </tr> <tr> <td>Event Duration:</td> <td>0.00</td> <td>Hours</td> <td>- Estimated 3 months before sales line</td> </tr> <tr> <td></td> <td>379.49</td> <td>Scf/lb-mol</td> <td>- Typical/Constant Conversion Value</td> </tr> </table> <p style="margin-top: 10px;">* It is assumed that all produced natural gas is sent to a sales line after the well is completed.</p> <p style="margin-top: 20px; text-align: center;">Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr ** Multiply above equation by 0.05 if including 95% control efficiency</p> <p>Combusted Component Emissions:</p> <table border="1" style="width: 100%; border-collapse: collapse; margin-top: 10px;"> <thead> <tr> <th style="width: 20%;">Component</th> <th style="width: 10%;">Mole % *</th> <th style="width: 10%;">Mole Weight lb/lb-mole</th> <th style="width: 10%;">Emissions Scf/hr</th> <th style="width: 10%;">Emissions lbs/hour</th> <th style="width: 10%;">Emissions Tons/Year</th> </tr> </thead> <tbody> <tr><td>Methane</td><td>88.9720</td><td>16.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethane</td><td>5.7920</td><td>30.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Propane</td><td>1.3650</td><td>44.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Butane</td><td>0.3700</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Butane</td><td>0.2610</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Pentane</td><td>0.1550</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Pentane</td><td>0.1020</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Other Pentanes</td><td>0.0000</td><td>70.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hexanes</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Heptanes</td><td>0.0930</td><td>100.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Octanes</td><td>0.0440</td><td>114.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nonanes</td><td>0.0160</td><td>128.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Decanes +</td><td>0.0050</td><td>142.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Benzene</td><td>0.0270</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Toluene</td><td>0.0190</td><td>92.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethylbenzene</td><td>0.0000</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>2,2,4 Trimethylpentane</td><td>0.0000</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Xylenes</td><td>0.0110</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Hexane</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nitrogen</td><td>0.0940</td><td>28.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Carbon Dioxide</td><td>2.5280</td><td>44.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hydrogen Sulfide</td><td>0.0000</td><td>34.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td colspan="6"> </td></tr> <tr> <td>VOC Subtotal</td> <td>2.7600</td> <td>1492.8</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>HAPS Subtotal</td> <td>0.2030</td> <td>546.9</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>Total</td> <td>100.1460</td> <td>1645.0</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> </tbody> </table>		Estimated Gas Flow Rate:	0	Scf/hr		Combustion Efficiency:	0.00	Percent (%)		Event Duration:	0.00	Hours	- Estimated 3 months before sales line		379.49	Scf/lb-mol	- Typical/Constant Conversion Value	Component	Mole % *	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year	Methane	88.9720	16.0	0.00	0.00	0.00	Ethane	5.7920	30.1	0.00	0.00	0.00	Propane	1.3650	44.1	0.00	0.00	0.00	i-Butane	0.3700	58.1	0.00	0.00	0.00	n-Butane	0.2610	58.1	0.00	0.00	0.00	i-Pentane	0.1550	72.2	0.00	0.00	0.00	n-Pentane	0.1020	72.2	0.00	0.00	0.00	Other Pentanes	0.0000	70.1	0.00	0.00	0.00	Hexanes	0.1460	86.2	0.00	0.00	0.00	Heptanes	0.0930	100.2	0.00	0.00	0.00	Octanes	0.0440	114.2	0.00	0.00	0.00	Nonanes	0.0160	128.3	0.00	0.00	0.00	Decanes +	0.0050	142.3	0.00	0.00	0.00	Benzene	0.0270	78.1	0.00	0.00	0.00	Toluene	0.0190	92.1	0.00	0.00	0.00	Ethylbenzene	0.0000	106.2	0.00	0.00	0.00	2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00	Xylenes	0.0110	106.2	0.00	0.00	0.00	n-Hexane	0.1460	86.2	0.00	0.00	0.00	Nitrogen	0.0940	28.0	0.00	0.00	0.00	Carbon Dioxide	2.5280	44.0	0.00	0.00	0.00	Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00							VOC Subtotal	2.7600	1492.8	0.00	0.00	0.00	HAPS Subtotal	0.2030	546.9	0.00	0.00	0.00	Total	100.1460	1645.0	0.00	0.00	0.00
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Octanes	0.0440	114.2	0.00	0.00	0.00																																																																																																																																																																														
Nonanes	0.0160	128.3	0.00	0.00	0.00																																																																																																																																																																														
Decanes +	0.0050	142.3	0.00	0.00	0.00																																																																																																																																																																														
Benzene	0.0270	78.1	0.00	0.00	0.00																																																																																																																																																																														
Toluene	0.0190	92.1	0.00	0.00	0.00																																																																																																																																																																														
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00																																																																																																																																																																														
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00																																																																																																																																																																														
Xylenes	0.0110	106.2	0.00	0.00	0.00																																																																																																																																																																														
n-Hexane	0.1460	86.2	0.00	0.00	0.00																																																																																																																																																																														
Nitrogen	0.0940	28.0	0.00	0.00	0.00																																																																																																																																																																														
Carbon Dioxide	2.5280	44.0	0.00	0.00	0.00																																																																																																																																																																														
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00																																																																																																																																																																														
VOC Subtotal	2.7600	1492.8	0.00	0.00	0.00																																																																																																																																																																														
HAPS Subtotal	0.2030	546.9	0.00	0.00	0.00																																																																																																																																																																														
Total	100.1460	1645.0	0.00	0.00	0.00																																																																																																																																																																														

Flare Combustion GHG emissions:					
	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year	
C1	88.97	0.00	0.00	0.00	
C2	5.79	0.00	0.00	0.00	
C3	1.37	0.00	0.00	0.00	
C4	0.63	0.00	0.00	0.00	
C5+	0.76	0.00	0.00	0.00	
CO₂ Total Emissions:				0.00	Tons/Year
N₂O Emissions:				0.00E+00	Tons/Year
Flare Combustion Emissions:					
		Fuel Heating Value:	1028.00	btu/scf	
		lbs/mmBTU	lbs/hour	Tons/event	
	CO	0.00	0.00	0.00	AP-42 CH13.5-1
	NOx	0.000	0.00	0.00	AP-42 CH13.5-1
	SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Production Phase

Production Equipment Fugitive Component Emissions

Assumptions:

Components Counts:

Component *	Fugitive Components				
	Valves	Connectors	OE Lines	PR Valves	
Count	97	348	12	6	0
Emissions Factor (scf/hr) ^b	0.121	0.017	0.031	0.193	0.000

* Fugitive component counts for natural gas wells from Subpart W, Table W-1B

* Fugitive component counts for oil wells from Subpart W, Table W-1C

Annual Equipment Run Time: 8760 Hours/Year 379.49 Scf/lb-mol

Component	Mole % ^a	Mole Weight lb/lb-mol	Emissions Scf/Year ^b	Emissions lbs/Year	Emissions Tons/Year
Methane	88.9720	16.0	149,511.3	6,320.6	3.16
Ethane	5.7920	30.1	9,733.1	771.2	0.39
Propane	1.3650	44.1	2,293.8	266.5	0.13
i-Butane	0.3700	58.1	621.8	95.2	0.05
n-Butane	0.2610	58.1	438.6	67.2	0.03
i-Pentane	0.1550	72.2	260.5	49.5	0.02
n-Pentane	0.1020	72.2	171.4	32.6	0.02
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	245.3	55.7	0.03
Heptanes	0.0930	100.2	156.3	41.3	0.02
Octanes	0.0440	114.2	73.9	22.3	0.01
Nonanes	0.0160	128.3	26.9	9.1	0.00
Decanes +	0.0050	142.3	8.4	3.2	0.00
Benzene	0.0270	78.1	45.4	9.3	0.00
Toluene	0.0190	92.1	31.9	7.8	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	18.5	5.2	0.00
n-Hexane	0.1460	86.2	245.3	55.7	0.03
Nitrogen	0.0940	28.0	158.0	11.7	0.01
Carbon Dioxide	2.5280	44.0	4,248.1	492.7	0.25
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600			720.50	0.36
HAPS Subtotal	0.2030			77.98	0.04
Total	100.1460			8316.67	4.16

Calculation

$$\text{lb/hr} = (\text{Mol \%} * \text{SumSCF/yr}) / \text{scf/lb-mol}$$

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b Fugitive emission factors from Subpart W, Table W-1A

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Production Phase
Process Heater Emissions

Wellsite Heater Inventory:

	Heating Value (Mbtu/hr)	Fuel Consumption (MMScf/yr)	
Separator Heater	750	6.44	* Heater treater size based on industry standard
Dehydrator Heater	500	4.29	
Glycol Reboiler	80	0.69	
Line Heater	500	4.29	
Annual Run Time:	8760	Hours/Year	
Fuel Gas Heat Value:	1,020	Btu/scf (Standard heating value from AP-42)	

Equations:

$$\text{Fuel Consumption (MMscf/yr)} = \frac{\text{Heater Size (MBtu/hr)} * 1,000 \text{ (Btu/MBtu)} * \text{Hours of Operation (hrs/yr)}}{\text{Fuel Heat Value (Btu/scf)} * 1,000,000 \text{ (scf/MMscf)}}$$

$$\text{NOx/CO/TOC Emissions (tons/yr)} = \frac{\text{AP-42 E.Factor (lbs/MMscf)} * \text{Fuel Consumption (MMscf/yr)} * \text{Fuel heating Value (Btu/scf)}}{2,000 \text{ (lbs/ton)} * 1,020 \text{ (Btu/scf - Standard Fuel Heating Value)}}$$

	Emission Factor (lb/MMscf)	Separator Heater Total Emissions (Tons/Year)	Dehydrator Heater Total Emissions (Tons/Year)	Glycol Reboiler Total Emissions (Tons/Year)	Line Heater Total Emissions (Tons/Year)	Total Emissions (Tons/Year) ^c
<i>Criteria Pollutants & VOC</i>						
NOx ^a	100	0.3221	0.2147	0.0344	0.2147	0.7858
CO ^a	84.0	0.2705	0.1804	0.0289	0.1804	0.6601
VOC	5.5	0.0177	0.0118	0.0019	0.0118	0.0432
SO ₂ ^b	0.00	0.0000	0.0000	0.0000	0.0000	0.0000
TSP ^c	7.60	0.0245	0.0163	0.0026	0.0163	0.0597
PM ₁₀ ^c	7.60	0.0245	0.0163	0.0026	0.0163	0.0597
PM _{2.5} ^c	7.60	0.0245	0.0163	0.0026	0.0163	0.0597
<i>Hazardous Air Pollutants</i>						
Benzene ^d	2.10E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Toluene ^d	3.40E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Hexane ^d	1.80	0.0058	0.0039	0.0006	0.0039	0.0141
Formaldehyde ^d	7.50E-02	0.0002	0.0002	0.0000	0.0002	0.0006
<i>Greenhouse Gases</i>						
CO ₂ ^f	120,162	386.9918	257.9945	41.2791	257.9945	944.2600
CH ₄ ^f	2.27	0.0073	0.0049	0.0008	0.0049	0.0178
N ₂ O ^f	0.23	0.0007	0.0005	0.0001	0.0005	0.0018

a AP-42 Table 1.4-1, Emission Factors for Natural Gas Combustion, 7/98

b Assumes produced gas contains no sulfur

c AP-42 Table 1.4-2, Emission Factors for Natural Gas Combustion, 7/98 (All Particulates are PM_{1.0})

d AP-42 Table 1.4-3, Emission Factors for Organic Compounds from Natural Gas Combustion, 7/98

e Assumes maximum development scenario

f Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.

Kleinfelder, Inc. Wellsite Emissions			Base Location: Upper Green River Basin Well Type: Natural Gas			
Production Phase						
Atmospheric Oil Tank Flashing Emissions						
Assumptions:						
Production Estimate:		30	barrels/day			
Production Days:		365	Days/Year			
Flasing Gas-to-Oil Ratio:		98	Scf/bbl	379.49 Scf/lb-mol		
Control Efficiency:		95	Percent (%)			
Flashing Gas Composition:						
Component	Mole %	Mole Weight (lb/lb-mol)	Emissions (Uncontrolled) Scf/Year	Emissions (Uncontrolled) lbs/Year	Emissions (Uncontrolled) Tons/Year	Emissions (Controlled) Tons/Year
Methane	48.6355	16.043	521907.5505	22063.7246	11.0319	0.5516
Ethane	21.3989	30.07	229631.5959	18195.5311	9.0978	0.4549
Propane	14.9031	44.097	159925.1661	18583.4147	9.2917	0.4646
i-Butane	4.0847	58.123	43832.9157	6713.4854	3.3567	0.1678
n-Butane	3.6800	58.123	39490.08	6048.3331	3.0242	0.1512
i-Pentane	1.7781	72.150	19080.7911	3627.7084	1.8139	0.0907
n-Pentane	0.8467	72.150	9085.9377	1727.4511	0.8637	0.0432
Other Pentanes	0.0000	70.100	0	0.0000	0.0000	0.0000
Hexanes	1.3611	86.177	14605.9641	3316.8151	1.6584	0.0829
Heptanes	1.1842	100.204	12707.6502	3355.4438	1.6777	0.0839
Octanes	0.2217	114.231	2379.0627	716.1261	0.3581	0.0179
Nonanes	0.0693	128.258	743.6583	251.3377	0.1257	0.0063
Decanes +	0.0067	142.285	71.8977	26.9571	0.0135	0.0007
Benzene	0.1161	78.120	1245.8691	256.4687	0.1282	0.0064
Toluene	0.1927	92.130	2067.8637	502.0219	0.2510	0.0126
Ethylbenzene	0.0039	106.160	41.8509	11.7075	0.0059	0.0003
2,2,4 Trimethylpentane	0.0351	78.120	376.6581	77.5370	0.0388	0.0019
Xylenes	0.1152	106.160	1236.2112	345.8225	0.1729	0.0086
n-Hexane	0.4064	86.177	4361.0784	990.3414	0.4952	0.0248
Nitrogen	0.0000	28.013	0	0.0000	0.0000	0.0000
Carbon Dioxide	0.9608	44.010	10310.3448	1195.7055	0.5979	0.0299
Hydrogen Sulfide	0.0000	34.080	0	0.0000	0.0000	0.0000
VOC Subtotal	29.01				23.28	1.16
HAPS Subtotal	0.87				1.09	0.05
Total	100.0002				44.0030	2.2001
Calculation:						
Scf/yr = (Mol% * scf/bbl * bbl/day * days/yr) / 100						
lb/yr = (scf/yr * mol wt.) / scf/lb-mol						
* Production and gas to oil ratio based on basin specific differences. Please see "Gas Stream Molar Ratios" tab and report for additional information.						

Kleinfelder, Inc. Wellsite Emissions	Base Location: Upper Green River Basin Well Type: Natural Gas									
Production Phase										
Wellsite Produced Water Tanks Venting										
Assumptions: Average Estimated Water Production: 3000 Barrels Per Year Number of Water Tanks: 1 Tanks VOC Emissions Factor: 0.2620 lbs/bbl n-Hexane Emission Factor: 0.0220 lbs/bbl Benzene Emission Factor: 0.0070 lbs/bbl										
Calculations: <table border="1"><tr><td>VOC Emissions:</td><td>0.393</td><td>Tons/Year</td></tr><tr><td>Hexane Emissions:</td><td>0.033</td><td>Tons/Year</td></tr><tr><td>Benzene Emissions:</td><td>0.0105</td><td>Tons/Year</td></tr></table> <ul style="list-style-type: none">* Production conservatively based on estimated industry single well average* Emission factors based on only known lb/bbl factor, which was developed by the Colorado Department of Health and Environment (PS Memo 09-02).		VOC Emissions:	0.393	Tons/Year	Hexane Emissions:	0.033	Tons/Year	Benzene Emissions:	0.0105	Tons/Year
VOC Emissions:	0.393	Tons/Year								
Hexane Emissions:	0.033	Tons/Year								
Benzene Emissions:	0.0105	Tons/Year								

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Upper Green River Basin
Well Type: Natural Gas

Production Phase
Truck Loading Emissions

AP - 42, Chapter 5.2

$$L_L = 12.46 \times S \times P \times M / T$$

L_L = Loading Loss Emission Factor (lbs VOC/1000 gal loaded)
 S = Saturation Factor
 P = True Vapor Pressure of the Loaded Liquid (psia)
 M = Vapor Molecular Weight of the Loaded Liquid (lbs/lbmol)
 T = Temperature of Loaded Liquid (°R)

$$\text{VOC Emissions (tpy)} = \frac{L_L (\text{lbs VOC}/1000 \text{ gal}) \times 42 \text{ gal/bbl} \times 365 \text{ days/year} \times \text{production (bbl/day)}}{1000 \text{ gal} \times 2000 \text{ lbs/ton}}$$

S ¹	P (psia) ²	M (lb/lbmol) ³	T (°F) ⁴	T (°R)	L _L (lb/1000 gal)	Production (bbl/day)	VOC (tpy)
0.6	3.40	66.00	40.00	499.67	3.36	30.0	0.77

- Notes:
1. Saturation factor from AP-42, Table 5.2-1 (Submerged loading: dedicated normal service)
 2. True vapor pressure is estimated from AP-42, Table 7.1-2 assuming an average daily temperature of either 40 or 50 deg F and an RVP of 10.0.
 3. Molecular weight liquid vapor is estimated from AP-42, Table 7.1-2 assuming an RVP of 10.0.
 4. Temperature based on the annual average temperature for basin location (either 40 or 50 degrees F based on options provided in AP-42 Table 7.1-2)

Kleinfelder, Inc. Wellsite Emissions	Base Location: Upper Green River Basin Well Type: Natural Gas																																																																																															
Production Phase Pumpjack Unit Emissions																																																																																																
<p>Assumptions:</p> <p style="text-align: center;">*Pumpjack engines only included at oil wells*</p> <div style="display: flex; justify-content: space-between; margin-top: 10px;"> <div style="width: 45%;"> Pumpjack Horsepower Rating: Load Factor: Brake Specific Fuel Consumption: Annual Operation: </div> <div style="width: 10%; text-align: center;"> 0.0 0.54 0 8,760 </div> <div style="width: 45%;"> Horsepower Btu/hp-hr Hours/Year </div> </div> <p style="margin-top: 10px;">Equations:</p> <div style="display: flex; justify-content: space-between; margin-top: 10px;"> <div style="width: 35%;">Emissions (lbs/hr) =</div> <div style="width: 60%; text-align: center;"> $\frac{\text{Emission Factor (g/hp-hr)} * \text{Power (hp)}}{453.6 \text{ g/lb}}$ </div> </div>																																																																																																
<table border="1" style="width: 100%; border-collapse: collapse; text-align: center;"> <thead> <tr> <th style="width: 25%;">Pollutant</th> <th style="width: 15%;">Emission Factor ^a (lb/MMBtu)</th> <th style="width: 15%;">Emission Factor ^a (g/hp-hr)</th> <th style="width: 15%;">Emissions (lb/hr)</th> <th style="width: 30%;">Emissions (Tons/Year)</th> </tr> </thead> <tbody> <tr> <td colspan="5"><i>Criteria Pollutants & VOC</i></td> </tr> <tr> <td>NOx</td> <td></td> <td>2.80</td> <td>0.00</td> <td>0.0000</td> </tr> <tr> <td>CO</td> <td></td> <td>4.80</td> <td>0.00</td> <td>0.0000</td> </tr> <tr> <td>VOC</td> <td>0.12</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td>PM₁₀ ^b</td> <td>4.83E-02</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>PM_{2.5} ^b</td> <td>4.83E-02</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>SO₂</td> <td>5.88E-04</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td colspan="5"><i>Hazardous Air Pollutants</i></td> </tr> <tr> <td>Benzene</td> <td>1.94E-03</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Toluene</td> <td>9.63E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Ethylbenzene</td> <td>1.08E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Xylenes</td> <td>2.68E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td>Formaldehyde</td> <td>5.52E-02</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td>n-Hexane</td> <td>4.45E-04</td> <td>-</td> <td>0.00E+00</td> <td>0.00E+00</td> </tr> <tr> <td colspan="5"><i>Greenhouse Gases</i></td> </tr> <tr> <td>CO₂ ^c</td> <td>117</td> <td>-</td> <td>0.00</td> <td>0</td> </tr> <tr> <td>CH₄</td> <td>0.002</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> <tr> <td>N₂O</td> <td>0.0002</td> <td>-</td> <td>0.0000</td> <td>0.0000</td> </tr> </tbody> </table>		Pollutant	Emission Factor ^a (lb/MMBtu)	Emission Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	<i>Criteria Pollutants & VOC</i>					NOx		2.80	0.00	0.0000	CO		4.80	0.00	0.0000	VOC	0.12	-	0.0000	0.0000	PM₁₀ ^b	4.83E-02	-	0.00E+00	0.00E+00	PM_{2.5} ^b	4.83E-02	-	0.00E+00	0.00E+00	SO₂	5.88E-04	-	0.0000	0.0000	<i>Hazardous Air Pollutants</i>					Benzene	1.94E-03	-	0.00E+00	0.00E+00	Toluene	9.63E-04	-	0.00E+00	0.00E+00	Ethylbenzene	1.08E-04	-	0.00E+00	0.00E+00	Xylenes	2.68E-04	-	0.00E+00	0.00E+00	Formaldehyde	5.52E-02	-	0.0000	0.0000	n-Hexane	4.45E-04	-	0.00E+00	0.00E+00	<i>Greenhouse Gases</i>					CO₂ ^c	117	-	0.00	0	CH₄	0.002	-	0.0000	0.0000	N₂O	0.0002	-	0.0000	0.0000
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<p>^a AP-42 Table 3.2-3 Uncontrolled Emission Factors for 4-Stroke Rich-Burn Engines, 7/00; and Subpart JJJJ for NOX and CO emission rates.</p> <p>^b PM = sum of PM filterable and PM condensable</p> <p>^c Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.</p> <p style="margin-top: 10px;">- Network website for the 1999 National-Scale Air Toxics Assessment at http://www.epa.gov/ttn/atw/nata1999/nsata99.html</p>																																																																																																

Kleinfelder, Inc. Wellsite Emissions	Base Location: Upper Green River Basin Well Type: Natural Gas																								
Production Phase																									
Wellsite Dehydrator Emissions																									
<p>Assumptions:</p> <p>Number of Dehy Units: 1 Units</p> <p>Calculations:</p> <p>Calculations and specifications derived from Pinedale Anticline Final SEIS GRI-GLYCalc 4.0 operated with: 4 MMSCFD, 0.32 gpm glycol flow, average representative gas analysis, and 95% control efficiency</p> <p>Emissions:</p> <table border="1" data-bbox="553 987 1062 1478"> <thead> <tr> <th>Species</th><th>Total Project Emissions (tons/year)</th></tr> </thead> <tbody> <tr> <td>Total VOC</td><td>0.630</td></tr> <tr> <td colspan="2"><i>Hazardous Air Pollutants</i></td></tr> <tr> <td>Benzene</td><td>0.070</td></tr> <tr> <td>Toluene</td><td>0.190</td></tr> <tr> <td>Ethylbenzene</td><td>0.010</td></tr> <tr> <td>Xylenes</td><td>0.150</td></tr> <tr> <td>n-Hexane</td><td>0.010</td></tr> <tr> <td colspan="2"><i>Greenhouse Gases</i></td></tr> <tr> <td>CO₂</td><td>0.000</td></tr> <tr> <td>CH₄^a</td><td>0.000</td></tr> <tr> <td>N₂O</td><td>0.000</td></tr> </tbody> </table> <p>Note, no greenhouse gas emissions included for dehydrator in Pinedale EIS</p>		Species	Total Project Emissions (tons/year)	Total VOC	0.630	<i>Hazardous Air Pollutants</i>		Benzene	0.070	Toluene	0.190	Ethylbenzene	0.010	Xylenes	0.150	n-Hexane	0.010	<i>Greenhouse Gases</i>		CO₂	0.000	CH₄^a	0.000	N₂O	0.000
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Kleinfelder, Inc. Wellsite Emissions			Base Location: Upper Green River Basin Well Type: Natural Gas																																																																			
Construction Phase																																																																						
Roadway Construction Traffic Tailpipe Emissions																																																																						
Assumptions:																																																																						
Average Round Trip Distance:		40.0	Miles/Trip Average																																																																			
Light Duty Pickup Trucks:		50	Trips/Location																																																																			
Light Duty Haul Trucks		0	Trips/Location		Total Trips: 50 Trips																																																																	
Heavy Duty Haul Trucks		2	Trips/Location																																																																			
Water Trucks		40	Trips/Location		Total Trips: 42 Trips																																																																	
* Miles and number of trips based on research and industry knowledge; please see report for additional information.																																																																						
Equations:																																																																						
Emissions (tons/year) = $\frac{\text{Emission Factor (g/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$																																																																						
<table><tr><th rowspan="2">Construction Vehicles</th><th colspan="2">Heavy Haul Trucks</th><th colspan="2">Light Duty Pickups</th><th>Total</th></tr><tr><th>E. Factor ^a (lb/mile)</th><th>Emissions (Tons/Location)</th><th>E. Factor ^b (lb/mile)</th><th>Emissions (Tons/Location)</th><th>Emissions (Tons/Location)</th></tr><tr><td>NOx</td><td>7.44E-02</td><td>6.25E-02</td><td>7.39E-03</td><td>7.39E-03</td><td>6.99E-02</td></tr><tr><td>CO</td><td>1.98E-02</td><td>1.66E-02</td><td>7.26E-02</td><td>7.26E-02</td><td>8.92E-02</td></tr><tr><td>VOC</td><td>3.16E-03</td><td>2.65E-03</td><td>3.54E-03</td><td>3.54E-03</td><td>6.19E-03</td></tr><tr><td>SO2</td><td>4.57E-05</td><td>3.84E-05</td><td>2.83E-05</td><td>2.83E-05</td><td>6.67E-05</td></tr><tr><td>PM10</td><td>4.22E-03</td><td>3.54E-03</td><td>1.94E-04</td><td>1.94E-04</td><td>3.74E-03</td></tr><tr><td>PM2.5</td><td>4.09E-03</td><td>3.44E-03</td><td>1.79E-04</td><td>1.79E-04</td><td>3.61E-03</td></tr><tr><td>CO2</td><td>1.88E+00</td><td>1.58E+00</td><td>1.13E+00</td><td>1.13E+00</td><td>2.70E+00</td></tr><tr><td>CH4</td><td>7.61E-05</td><td>6.39E-05</td><td>4.56E-05</td><td>4.56E-05</td><td>1.10E-04</td></tr><tr><td>N2O</td><td>1.52E-05</td><td>1.28E-05</td><td>9.13E-06</td><td>9.13E-06</td><td>2.19E-05</td></tr></table>						Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)	NOx	7.44E-02	6.25E-02	7.39E-03	7.39E-03	6.99E-02	CO	1.98E-02	1.66E-02	7.26E-02	7.26E-02	8.92E-02	VOC	3.16E-03	2.65E-03	3.54E-03	3.54E-03	6.19E-03	SO2	4.57E-05	3.84E-05	2.83E-05	2.83E-05	6.67E-05	PM10	4.22E-03	3.54E-03	1.94E-04	1.94E-04	3.74E-03	PM2.5	4.09E-03	3.44E-03	1.79E-04	1.79E-04	3.61E-03	CO2	1.88E+00	1.58E+00	1.13E+00	1.13E+00	2.70E+00	CH4	7.61E-05	6.39E-05	4.56E-05	4.56E-05	1.10E-04	N2O	1.52E-05	1.28E-05	9.13E-06	9.13E-06	2.19E-05
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a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.																																																																						
b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.																																																																						
c Assumes maximum development scenario																																																																						

Kleinfelder, Inc. Wellsite Emissions			Base Location: Upper Green River Basin Well Type: Natural Gas				
Production Phase Pneumatic Device Emissions							
Wellsite Pneumatic Inventory:							
Devices:	Dump Valve Pneumatic Controller	Classification Intermittent Bleed Low Bleed	Quantity 4 1 0	Emission Factor (Scf/hr/unit) 13.50 1.39 0.00			
Pumps:	Chemical Pump Sandpiper Gycol Pump	Pneumatic Pump Pneumatic Pump Pneumatic Pump	1 1 1	13.30			
Annual Equipment Run Time:	8760	Hours/Year	379.49 Scf/lb-mol				
Pneumatic Device Control: ^b	98	Percent					
* Low bleed and intermittent bleed emission factors (scf/hr) based on Subpart W, Table W-1A * Quantity of devices based on typical industry values							
Component	Mole %	Mole Weight lb/lb-mol	Dump Valve Tons/Year	Pneumatic Controller Tons/Year	(None) Tons/Year	Pneumatic Pumps Tons/Year	Total Tons/Year
Methane	88.9720	16.0	8.896	0.229	0.000	0.131	9.257
Ethane	5.7920	30.1	1.085	0.028	0.000	0.016	1.129
Propane	1.3650	44.1	0.375	0.010	0.000	0.006	0.390
i-Butane	0.3700	58.1	0.134	0.003	0.000	0.002	0.139
n-Butane	0.2610	58.1	0.095	0.002	0.000	0.001	0.098
i-Pentane	0.1550	72.2	0.070	0.002	0.000	0.001	0.073
n-Pentane	0.1020	72.2	0.046	0.001	0.000	0.001	0.048
Other Pentanes	0.0000	70.1	0.000	0.000	0.000	0.000	0.000
Hexanes	0.1460	86.2	0.078	0.002	0.000	0.001	0.082
Heptanes	0.0930	100.2	0.058	0.001	0.000	0.001	0.060
Octanes	0.0440	114.2	0.031	0.001	0.000	0.000	0.033
Nonanes	0.0160	128.3	0.013	0.000	0.000	0.000	0.013
Decanes +	0.0050	142.3	0.004	0.000	0.000	0.000	0.005
Benzene	0.0270	78.1	0.013	0.000	0.000	0.000	0.014
Toluene	0.0190	92.1	0.011	0.000	0.000	0.000	0.011
Ethylbenzene	0.0000	106.2	0.000	0.000	0.000	0.000	0.000
2,2,4 Trimethylpentane	0.0000	78.1	0.000	0.000	0.000	0.000	0.000
Xylenes	0.0110	106.2	0.007	0.000	0.000	0.000	0.008
n-Hexane	0.1460	86.2	0.078	0.002	0.000	0.001	0.082
Nitrogen	0.0940	28.0	0.016	0.000	0.000	0.000	0.017
Carbon Dioxide	2.5280	44.0	0.693	0.018	0.000	0.010	0.722
Hydrogen Sulfide	0.0000	34.1	0.000	0.000	0.000	0.000	0.000
VOC Subtotal	2.8	1492.8	1.01	0.03	0.00	0.01	1.06
HAPS Subtotal	0.2	546.9	0.11	0.00	0.00	0.00	0.11
Total	100.1	1645.0	11.71	0.30	0.00	0.17	12.18
^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells. ^b 98% control input is a result of the Wyoming Department of Environment Quality requirement, and only pertains to the Upper Green River Basin.							

APPENDIX D

EMISSION INVENTORY FOR THE SAN JUAN BASIN GAS WELL

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Location Selection:

Geography:

San Juan Basin

Well Type:

Natural Gas

- Choose geography/basin, and well type will automatically fill
- < Choose Uinta/Piceance Basin for deep gas wells with little condensate
- < Choose Upper Green River Basin for deep gas wells with dehydrators and higher condensate
- < Choose San Juan Basin for shallow gas wells with little to no condensate
- < Choose Williston Basin for deep oil wells with high gas
- < Choose Denver Basin for shallow oil wells with low gas

If the user wants to change any specifications, do so within the "Constants and References" tab, as all other tabs connect to it.

Pollutant:	Total Emissions (Tons per Year)								
	NO _x	CO	VOC	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O
Construction Phase:	0.47	0.29	0.04	0.0001	2.05	0.06	33.84	0.001	0.0003
Development Phase:	4.04	1.08	0.30	0.0002	4.67	0.14	561.61	1.05	0.0389
Operation Phase:	1.06	1.75	4.98	0.0008	0.08	0.27	56.44	4.99	0.0004
Total:	5.57	3.12	5.32	0.0010	6.81	0.48	651.89	6.05	0.0396

Pollutant:	Total Emissions (Tons per Year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	HAPs
Construction Phase:	0.00	0.00	0.00	0.00	0.00	0.00
Development Phase:	1.35	0.95	0.0000	0.55	7.31	10.17
Operation Phase:	0.03	0.02	0.00078	0.008	0.18	0.31
Total:	1.38	0.97	0.00078	0.56	7.49	10.48

CO ₂ equivalent (Global Warming Potential)	
Total TPY:	791.23
CO ₂ equivalent conversions:	
CO ₂ 1.00	
CH ₄ 21.00	
N ₂ O 310.00	

H ₂ S Emissions	
Total TPY:	0.00

* If H₂S in gas, input value in "Gas Stream Molar Ratios" tab, and potential emissions will calculate here. Current assumption is no H₂S in gas stream.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Road Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	4	Days/Location	(Typical Value)
	48.0	Dozer Hours/Location	(Typical Value)
	48.0	Backhoe Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98

PM₁₀ Multiplier: 0.75 * PM₁₅ (AP-42 Table 11.9-1, 7/98)

PM_{2.5} Multiplier: 0.105 * TSP (AP-42 Table 11.9-1, 7/98)

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98 & 7/98

Emissions (TSP lbs/hr) = 5.7 * (soil silt content %) ^{1.2} * (soil moisture content %) ^{-1.3} * Control Efficiency

Emissions (PM₁₅ lbs/hr) = 1.0 * (soil silt content %) ^{1.5} * (soil moisture content %) ^{-1.4} * Control Efficiency

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0473	1.97	0.0473	0.0946
PM₁₅	0.50	0.0120	0.50	0.0120	0.0241
PM₁₀	0.38	0.0090	0.38	0.0090	0.0181
PM_{2.5}	0.21	0.0050	0.05	0.0013	0.0062

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase
Road Grader Particulate Matter

Assumptions:

Grading Length:	6.00	miles	(Typical Value)
Construction Schedule:	3	Days/Location	(Typical Value)
	12	Hours/Day	(Typical Value)
	36	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	
Average Grader Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 16.12 lbs TSP/Location

Emissions = 7.71 lbs PM₁₅/Location

Grader Construction Emissions			
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	16.12	0.45	8.06E-03
PM₁₅	7.71	0.21	3.86E-03
PM₁₀	4.63	0.13	2.31E-03
PM_{2.5}	0.50	0.01	2.50E-04

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Well Pad Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location (Dozer)	(Typical Value)
	70	Hours/Location (Back Hoe)	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase
Well Pad Grader Particulate Matter

Assumptions:

Construction Schedule:	4.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	40	Hours/Location	(Typical Value)
Watering Control Efficiency	50	Percent (%)	(Typical Value)
Average Grader Speed	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
Distance Graded	2.84	Miles/Location	(Typical Value)
PM ₁₀ Multiplier	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 7.63 lbs TSP/well pad

Emissions = 3.65 lbs PM₁₅/well pad

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	7.63	0.19	0.0038
PM₁₅	3.65	0.09	0.0018
PM₁₀	2.19	0.05	0.0011
PM_{2.5}	0.24	0.01	0.0001

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Pipeline Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs/hr) = $5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs/hr) = $1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Pipeline Grader Particulate Matter

Assumptions:

Distance Graded:	12.50	Miles/Location	(Typical Value)
Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Mean Vehicle Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs) = $0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs) = $0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions = 33.58 lbs TSP/well

Emissions = 16.07 lbs PM₁₅/well

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	33.58	0.48	0.0168
PM₁₅	16.07	0.23	0.0080
PM₁₀	9.64	0.14	0.0048
PM_{2.5}	1.04	0.01	0.0005

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Heavy Diesel Truck Trips:

Road Construction:	7	Trips			
Well Pad Construction:	8	Trips	Total Trips:	21	Trips
Pipeline Construction:	6	Trips			

Light Duty Pickup Truck Trips:

Road Construction:	16	Trips			
Well Pad Construction:	28	Trips	Total Trips:	100	Trips
Pipeline Construction:	56	Trips			

* All assumptions above are based on typical industry values

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a	Emissions	E. Factor ^b	Emissions	Emissions
	(lb/mile)	(Tons/Location)	(lb/mile)	(Tons/Location)	(Tons/Location)
NOx	7.44E-02	3.12E-02	7.39E-03	1.48E-02	4.60E-02
CO	1.98E-02	8.32E-03	7.26E-02	1.45E-01	1.54E-01
VOC	3.16E-03	1.33E-03	3.54E-03	7.08E-03	8.41E-03
SO2	4.57E-05	1.92E-05	2.83E-05	5.66E-05	7.58E-05
PM10	4.22E-03	1.77E-03	1.94E-04	3.88E-04	2.16E-03
PM2.5	4.09E-03	1.72E-03	1.79E-04	3.58E-04	2.08E-03
CO2	1.88	0.79	1.13	2.25	3.04
CH4	7.61E-05	3.19E-05	4.56E-05	9.13E-05	1.23E-04
N2O	1.52E-05	6.39E-06	9.13E-06	1.83E-05	2.46E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Construction Heavy Equipment Tailpipe Emissions

Assumptions:

Fuel and Engine:

Brake Specific Fuel Consumption, Avg. (BSFC) 8250 btu/hp-hr (Typical Value)
Diesel Higher Heating Value (HHV) 0.138 mmBtu/Gallon (Typical Value)

Trackhoe:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 100 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Tractors/Loaders/Backhoes)

Dozer:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 140 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Crawler Tractor/Dozers)

Grader:

Working Hours 130 Total Hours (Typical Value)
Rated Horsepower 250 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Graders)

Total Horsepower Hours: 45795.8 Hp-hrs (Sum of all horsepower above)
Total Fuel Usage: 2737.79 Gallons Diesel Fuel

Equations:

Total Fuel Usage: (btu-hp-hr * hp-hrs) / Mmbtu-gal) / 1,000,000
Emissions (tons/year/pad) = $\frac{\text{Emission Factor (g/mile)} * \text{Trip Distance (miles)} * \text{Load Factor}}{453.6 \text{ (g/lb)} * 2000 \text{ (lb/tons)}}$

Heavy Const. Vehicles	Backhoe			Dozer			Grader		
	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
NOx	8.38	1.09E+00	1.02E-01	8.38	1.53E+00	1.43E-01	8.38	2.72E+00	1.77E-01
CO	2.7	3.51E-01	3.30E-02	2.7	4.92E-01	4.62E-02	2.7	8.78E-01	5.71E-02
VOC ^b	0.68	8.84E-02	8.31E-03	0.68	1.24E-01	1.16E-02	0.68	2.21E-01	1.44E-02
PM₁₀	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03
PM_{2.5}	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03

Heavy Const. Vehicles	Total Emissions ^c (tons/yr)
NOx	0.42
CO	0.14
VOC	0.03
PM₁₀	0.02
PM_{2.5}	0.02

Greenhouse Gas Emissions:

	Diesel EF kg/mmbtu	Emissions lbs	Emissions Tons
CO ₂	73.96	61604.19	30.80
CH ₄	0.003	2.50	0.0012
N ₂ O	0.0006	0.50	0.0002

a From Table A-4 of Exhaust and Crankcase Emission Factors for NONROAD Engine Modeling - Compression Ignition, EPA-420-R-10-018, July 2010.

b Emission Factor represents total Hydrocarbon Emissions

c Converted from emission factor for Distillate Fuel Oil #2 (diesel) as listed in Table C-1 to Subpart C of Part 98 - Default Emission Factors and High Heat Values for Various Types of Fuel.

Listed Factor:

73.96 kg CO₂/mmBtu
393 hp-hr = mmBtu
188.2 g CO₂/hp-hr

Kleinfelder, Inc. Wellsite Emissions		Base Location: San Juan Basin Well Type: Natural Gas													
Construction Phase															
Wind Erosion Fugitive Dust															
Assumptions:															
Threshold Friction Velocity (U _t)	1.02 1.33	m/s (2.28 mph) for well pads (AP-42 Table 13.2.5-2 Overburden - Western Surface Coal Mine) m/s (2.97 mph) for roads (AP-42 Table 13.2.5-2 Roadbed material)													
Initial Disturbance Area															
Total Access Road/ROW Area Per Location:	976,800	Square Meters	(Typical Value)												
Total Well Pad Area Disturbed Per Location:	50,000	Square Meters	(Typical Value)												
Total Area Disturbed Per Location:	1,026,800	Square Meters	(Typical Value)												
Exposed Surface Type	Flat														
Meteorological Data	2002 Grand Junction (obtained from NCDC website)														
Fastest Mile Wind Speed:	45	miles/hour	(Typical Value)												
Fastest Mile Wind Speed (U ₁₀ ⁺)	20.12	meters/sec (45 mph) reported as fastest 2-minute wind speed for Grand Junction (2002)													
Number soil of disturbances	1.00	for well pads (Assumption, disturbance at construction and reclamation) constant for dirt roads													
Equations (AP-42 13.2.5.2 Industrial Wind Erosion)															
Friction Velocity U* = 0.053 U ₁₀ ⁺															
Erosion Potential P (g/m ² /period) = 58*(U*-U _t *) ² + 25*(U*-U _t *) for U*>U _t *, P = 0 for U*< U _t *															
Emissions (tons/year) = Erosion Potential(g/m ² /period)*Disturbed Area(m ²)*Disturbances/year*(k)/(453.6 g/lb)/2000 lbs/ton/Develop Period															
<table><tr><th colspan="3">Particle Size Multiplier (k)</th></tr><tr><th>30 μm</th><th><10 μm</th><th><2.5 μm</th></tr><tr><td>1.0</td><td>0.5</td><td>0.075</td></tr></table>				Particle Size Multiplier (k)			30 μm	<10 μm	<2.5 μm	1.0	0.5	0.075			
Particle Size Multiplier (k)															
30 μm	<10 μm	<2.5 μm													
1.0	0.5	0.075													
<table><tr><th>Maxium U₁₀⁺ Wind Speed (m/s)</th><th>Maximum U* Friction Velocity m/s</th><th>Well U_t* Threshold Velocity^a m/s</th><th>Well Pad Erosion Potential g/m²</th><th>Road U_t* Threshold Velocity^a m/s</th><th>Road Erosion Potential g/m²</th></tr><tr><td>20.12</td><td>1.07</td><td>1.02</td><td>1.28</td><td>1.33</td><td>0.00</td></tr></table>				Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²	20.12	1.07	1.02	1.28	1.33	0.00
Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²										
20.12	1.07	1.02	1.28	1.33	0.00										
Wind Erosion Emissions															
<table><tr><th>Particulate Species</th><th>Well Pad (tons/year)</th><th>Roads/Pipelines (tons/year)</th></tr><tr><td>TSP</td><td>7.05E-02</td><td>0.00E+00</td></tr><tr><td>PM₁₀</td><td>3.52E-02</td><td>0.00E+00</td></tr><tr><td>PM_{2.5}</td><td>5.28E-03</td><td>0.00E+00</td></tr></table>				Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)	TSP	7.05E-02	0.00E+00	PM ₁₀	3.52E-02	0.00E+00	PM _{2.5}	5.28E-03	0.00E+00
Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)													
TSP	7.05E-02	0.00E+00													
PM ₁₀	3.52E-02	0.00E+00													
PM _{2.5}	5.28E-03	0.00E+00													

Kleinfelder, Inc.				Base Location: San Juan Basin					
Website Emissions				Well Type: Natural Gas					
Construction, Development, and Production Phase									
Construction, Development, and Operations Traffic Fugitive Dust Emissions									
Assumptions:									
				Round Trip Miles	40				
				Round Trip (Paved) Miles	16				
				Round Trip (Un-Paved) Miles	24				
				Precipitation Days (P)	35				
Unpaved Calculation AP-42, Chapter 13.2.2 November 2006				$E (PM_{10}) / VMT = 1.5 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$ $E (PM_{2.5}) / VMT = 0.15 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
				Silt Content (S)	8.5		AP 42 13.2.2-1 Mean Silt Content Construction Sites		
Paved Calculation AP-42, Chapter 13.2.1 January 2011				$E (PM_{10}) / VMT = 0.0022 * (sL)^{0.91} * (W)^{0.62} * (1-(P/(365*4)))$ $E (PM_{2.5}) / VMT = 0.00054 * (sL)^{0.91} * (W)^{0.62} * (1-(P/(365*4)))$					
				Silt Loading (sL)	0.6		AP-42 Table 13.2.1-2 baseline low volume roads		
Unpaved Calculations:									
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	3.19	1607.6	0.8	0.3	160.8	0.1
	Light Duty Pickup Trucks	5,000	100	0.92	2198.4	1.1	0.1	219.8	0.1
	Total:				3806.00	1.90		380.60	0.19
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	0.0580	19.5	0.0098	0.014	4.8	0.0024
	Light Duty Pickup Trucks	5,000	100	0.0034	5.5	0.0027	0.001	1.3	0.0007
	Total:				25.0	0.0		6.1	0.0
Unpaved Calculations:									
Development Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	84	0.92	1846.7	0.9	0.1	184.7	0.1
	Light Duty Haul Trucks	7,500	11	1.10	290.2	0.1	0.1	29.0	0.0
	Heavy Duty Haul Trucks	80,000	67	3.19	5129.0	2.6	0.3	512.9	0.3
	Water Trucks	70,000	24	3.00	1730.1	0.9	0.3	173.0	0.1
	Total:				8996.02	4.50		899.60	0.45
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips						
	Light Duty Pickup Trucks	5000	84	0.00	4.6	0.0	0.0	1.1	0.0006
	Light Duty Haul Trucks	7500	11	0.01	0.9	0.0	0.0	0.2	0.0001
	Heavy Duty Haul Trucks	80000	67	0.06	62.2	0.0	0.0	15.3	0.0076
	Water Trucks	70,000	24	0.05	19.5	0.0	0.0	4.8	0.0024
	Total:				87.2	0.0		21.4	0.0
Unpaved Calculations:									
Production Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	50	0.92	1099.20	0.55	0.0916	109.92	0.0550
	Light Duty Haul Trucks	7,500	0	1.10	0.00	0.00	0.1999	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	3.19	153.11	0.08	0.3190	15.31	0.0077
	Water Trucks	70,000	40	3.00	2883.52	1.44	0.3004	288.35	0.1442
	Total:				4135.83	2.07		413.58	0.21
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	50	0.00	2.75	0.0014	0.0008	0.67	0.0003
	Light Duty Haul Trucks	7,500	0	0.01	0.00	0.0000	0.0013	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	0.06	1.86	0.0009	0.0142	0.46	0.0002
	Water Trucks	70,000	40	0.05	32.42	0.0162	0.0124	7.96	0.0040
	Total:				37.02	0.02		9.09	0.00
Annual Total					Unpaved Roads PM ₁₀ (tons) 8.47		Unpaved Roads PM _{2.5} (tons) 0.8		
					Paved Roads PM ₁₀ 0.1		Paved Roads PM _{2.5} 0.0		
					Total:		8.5		
							0.9		

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Development Phase
Drill Rig Emissions

Assumptions:

Parameter	Value
Days of Operation	12 (Typical Value)
Hours of Operation	288 (Typical Value)
Diesel Fuel Sulfur Content	0.000015 (Typical Value)

Parameter	Value	Units
BSFC (Avg.)	8250 (Typical Value)	btu/hp-hr
Diesel HHV	0.138 (Typical Value)	mmbtu/gal

Engine	HP *	Load Factor	Run time (hrs)	Total Hp-hrs
Vertical Drill Rig Engine	550	0.42	96	22176
Horizontal Drill Rig Engine	2,100	0.60	192	241920
Drill Rig Generator	350	0.42	288	42336
Trailers Generator	150	0.42	288	18144
Air Compressor	550	0.42	96	22176
Air Compressor	550	0.42	96	22176
Air Compressor Booster	650	0.42	96	26208
Forklift	120	0.42	96	4838.4
Aerial Lift	50	0.42	12	252
Frontend loader	150	0.42	12	756
Dozer	175	0.42	6	441
-	0	0.00	0	0
-	0	0.00	0	0
-	0	0.00	0	0
-	0	0.00	0	0

Total HP 5,395

Total: 401,423 Hp-hrs

Fuel Usage: 23,998 Gallons of Diesel Total Fuel Usage: (btu/hp-hr * hp-hrs) * gal/btu

Greenhouse Gasses:

	Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location
CO2	73.96	539991.94	270.00
CH4	0.003	21.90	0.01
N2O	0.0006	4.38	0.00

Greenhouse gas emission factors from Subpart C, Table C-1 and C-2

Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)
Vertical Drill Rig Engine	22176	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Horizontal Drill Rig Engine	241920	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Drill Rig Generator	42336	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Trailers Generator	18144	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Air Compressor	22176	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor	22176	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor Booster	26208	1.3272	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Forklift	4838.4	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Aerial Lift	252	3.4900	8.3800	0.7220	0.7003	1.27E-05	0.9900	7.76E-04	2.81E-04	1.93E-04
Frontend loader	756	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Dozer	441	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
-	0	0.0000	0.0000	0.0000	0.0000	1.27E-05	0.0000	0.00E+00	0.00E+00	0.00E+00
-	0	0.0000	0.0000	0.0000	0.0000	1.27E-05	0.0000	0.00E+00	0.00E+00	0.00E+00
-	0	0.0000	0.0000	0.0000	0.0000	1.27E-05	0.0000	0.00E+00	0.00E+00	0.00E+00

Engine	CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)
Vertical Drill Rig Engine	0.02059	0.10597	0.00322	0.00312	3.10E-07	0.00400	0.00007	0.00003	0.00002
Horizontal Drill Rig Engine	0.20379	1.09335	0.03509	0.03404	3.39E-06	0.04363	0.00077	0.00028	0.00019
Drill Rig Generator	0.12600	0.39107	0.01876	0.01820	5.93E-07	0.03173	0.00014	0.00005	0.00003
Trailers Generator	0.05400	0.16760	0.00804	0.00780	2.54E-07	0.01360	0.00006	0.00002	0.00001
Air Compressor	0.02059	0.10597	0.00322	0.00312	3.10E-07	0.00400	0.00007	0.00003	0.00002
Air Compressor	0.02059	0.10597	0.00322	0.00312	3.10E-07	0.00400	0.00007	0.00003	0.00002
Air Compressor Booster	0.03834	0.11845	0.00380	0.00369	3.67E-07	0.00473	0.00008	0.00003	0.00002
Forklift	0.01440	0.04469	0.00214	0.00208	6.77E-08	0.00363	0.00002	0.00001	0.00000
Aerial Lift	0.00097	0.00233	0.00020	0.00019	3.53E-09	0.00028	0.00000	0.00000	0.00000
Frontend loader	0.00225	0.00698	0.00034	0.00032	1.06E-08	0.00057	0.00000	0.00000	0.00000
Dozer	0.00131	0.00407	0.00020	0.00019	6.17E-09	0.00033	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
Total:	0.50285	2.14646	0.07822	0.07588	0.00001	0.11048	0.00128	0.00047	0.00032

Emission Factors

- Drill rig emission factors based on Tier II engines
- All other engine emission factors based on Tier 0 engines (typical values)
- HAP emission factors from AP-42 Volume I, Large Stationary Diesel Engines Table 3.4-3

Calculations:

ton/year: (Total hp-hr * g/hp-hr) * lb-gram / lb-ton

*** Drill rig horsepower developed based on:**

- 1 Williston Basin: 2,100 from Jonah, Wyoming RMP
- 2 San Juan Basin: 2,100 from River Valley RMP
- 3 Upper Green River Basin: 2,100 from Jonah, Wyoming RMP
- 4 Denver Basin: 2,950 from River Valley RMP
- 5 Uintah Basin: 2,952 from River Valley RMP

Note, runtime for each drilling event is based on research and industry experience dependent upon each basi

Kleinfelder, Inc. Wellsite Emissions					Base Location: San Juan Basin Well Type: Natural Gas																																			
Development Phase																																								
Conductor Pipe Set Emissions																																								
Assumptions:																																								
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Total Horsepower: 400					Greenhouse gas emission factors from Subpart C, Table C-1 and C-2																																			
Total: 4,032 Hp-hrs					Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)																																			
Fuel Usage: 241 Gallons of Diesel																																								
Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)																														
Rig Engine	3528	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	0.0008	0.0003	0.0002																														
Rig Generator	504	5.0000	6.9000	0.8000	0.7760	1.27E-05	1.8000	0.0008	0.0003	0.0002																														
Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																														
Rig Engine		0.00328	0.01686	0.00051	0.00050	0.00000	0.00064	0.00001	0.00000	0.00000																														
Rig Generator		0.00278	0.00383	0.00044	0.00043	0.00000	0.00100	0.00000	0.00000	0.00000																														
Total:		0.00605	0.02069	0.00096	0.00093	0.00000	0.00164	0.00001	0.00000	0.00000																														
Calculations:																																								
ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																								
* Rig engine emission rates are based on a Tier II engine and rig generator emission rates are based on a Tier 0 engine.																																								
* All days, hours, and HP values above are based on typical industry values																																								

[illegible]

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Development Phase

Hydraulic Fracturing Flowback Emissions

Assumptions:

Estimated Frac flowback Rate: 10,000 Scf/hr
Combustion Efficiency: 95.00 Percent (%)
Event Duration: 100.00 Hours
 379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Venting duration based on research and industry knowledge; please see report for additional information.

* Venting control based on Subpart OOOO requirements of 95% minimum control.

Control efficiency can be deleted if applicable.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr

** Multiply above equation by 0.02 if including 98% control efficiency

Un-combusted Componet Emissions:

Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	444.86	18.81	0.94
Ethane	5.7920	30.1	28.96	2.29	0.11
Propane	1.3650	44.1	6.83	0.79	0.04
i-Butane	0.3700	58.1	1.85	0.28	0.01
n-Butane	0.2610	58.1	1.31	0.20	0.01
i-Pentane	0.1550	72.2	0.78	0.15	0.01
n-Pentane	0.1020	72.2	0.51	0.10	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.73	0.17	0.01
Heptanes	0.0930	100.2	0.47	0.12	0.01
Octanes	0.0440	114.2	0.22	0.07	0.00
Nonanes	0.0160	128.3	0.08	0.03	0.00
Decanes +	0.0050	142.3	0.03	0.01	0.00
Benzene	0.0270	78.1	0.14	0.03	0.00
Toluene	0.0190	92.1	0.10	0.02	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.06	0.02	0.00
n-Hexane	0.1460	86.2	0.73	0.17	0.01
Nitrogen	0.0940	28.0	9.40	0.69	0.03
Carbon Dioxide	2.5280	44.0	252.80	29.32	1.47
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600	1492.8	13.80	2.14	0.11
HAPS Subtotal	0.2030	546.9	1.02	0.23	0.01
Total	100.1460	1645.0	749.82	53.26	2.66

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	8452.34	980.23	49.01
C2	5.79	550.24	63.81	3.19
C3	1.37	129.68	15.04	0.75
C4	0.63	59.95	6.95	0.35
C5+	0.76	72.58	8.42	0.42

CO₂ Total Emissions: 53.72 Tons/Event
N₂O Emissions: 1.13E-04 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.37	3.80	0.19	AP-42 CH13.5-1
NOx	0.068	0.70	0.03	AP-42 CH13.5-1
SO ₂	-	0.00	0.00	*Based on H2s 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions	Base Location: San Juan Basin Well Type: Natural Gas																																												
Development Phase																																													
Workover Cementing Emissions																																													
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<p>Total Horsepower: 1,500 (Typical Value)</p> <p>Total: 11,760 Hp-hrs</p> <p>Fuel Usage: 724 Gallons of Diesel Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)</p>	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>16298.85</td><td>8.15</td></tr><tr><td>CH4</td><td>0.003</td><td>0.66</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.13</td><td>0.00</td></tr></table>		Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	16298.85	8.15	CH4	0.003	0.66	0.00	N2O	0.0006	0.13	0.00																												
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Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Formaldehyde (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																																			
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Total: 0.01436 0.06369 0.00221 0.00214 0.00308 0.00004 0.00000 0.00001 0.00001																																													
Emission Factors - Engine emission factors based on Tier II engines (typical values)																																													
Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																													

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Development Phase
Well Venting During Workover Events

Assumptions:

Significant gas venting only occurs on natural gas wells.

Estimated Venting Rate: 5,000 Scf/Event (Typical Value)
Combustion Efficiency: 0.00 Percent (%)
Event Quantity: 1.00 Event - Assumed one event
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Vented quantity based on research and industry knowledge; please see report for additional information.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf-lb-mol)
** Multiply above equation by 0.02 if including 98% control efficiency

Component	Mole %	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Event
Methane	88.9720	16.0	4448.60	188.07	0.0940
Ethane	5.7920	30.1	289.60	22.95	0.0115
Propane	1.3650	44.1	68.25	7.93	0.0040
i-Butane	0.3700	58.1	18.50	2.83	0.0014
n-Butane	0.2610	58.1	13.05	2.00	0.0010
i-Pentane	0.1550	72.2	7.75	1.47	0.0007
n-Pentane	0.1020	72.2	5.10	0.97	0.0005
Other Pentanes	0.0000	70.1	0.00	0.00	0.0000
Hexanes	0.1460	86.2	7.30	1.66	0.0008
Heptanes	0.0930	100.2	4.65	1.23	0.0006
Octanes	0.0440	114.2	2.20	0.66	0.0003
Nonanes	0.0160	128.3	0.80	0.27	0.0001
Decanes +	0.0050	142.3	0.25	0.09	0.0000
Benzene	0.0270	78.1	1.35	0.28	0.0001
Toluene	0.0190	92.1	0.95	0.23	0.0001
Ethylbenzene	0.0000	106.2	0.00	0.00	0.0000
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.0000
Xylenes	0.0110	106.2	0.55	0.15	0.0001
n-Hexane	0.1460	86.2	7.30	1.66	0.0008
Nitrogen	0.0940	28.0	4.70	0.35	0.0002
Carbon Dioxide	2.5280	44.0	126.40	14.66	0.0073
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.0000

VOC Subtotal	2.7600	1492.8	138.00	21.44	0.0107
HAPS Subtotal	0.2030	546.9	10.15	2.32	0.0012
Total	100.1460	1645.0	5007.30	247.46	0.1237

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	0.00	0.00	0.00
C2	5.79	0.00	0.00	0.00
C3	1.37	0.00	0.00	0.00
C4	0.63	0.00	0.00	0.00
C5+	0.76	0.00	0.00	0.00

CO₂ Total Emissions: 0.00 Tons/Event
N₂O Emissions: 5.67E-07 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NOx	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.000	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions			Base Location: San Juan Basin Well Type: Natural Gas																																																																			
Development Phase																																																																						
Wellsite Development Traffic Tailpipe Emissions																																																																						
Assumptions:																																																																						
Average Round Trip Distance:		40.0	Miles/Trip Average																																																																			
Light Duty Pickup Trucks:		84	Trips/Location																																																																			
Light Duty Haul Trucks		11	Trips/Location		Total Trips: 95 Trips																																																																	
Heavy Duty Haul Trucks		67	Trips/Location																																																																			
Water Trucks		24	Trips/Location		Total Trips: 91 Trips																																																																	
* Miles and number of trips based on research and industry knowledge; please see report for additional information.																																																																						
Equations:																																																																						
Emissions (tons/year) = $\frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$																																																																						
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Kleinfelder, Inc. Wellsite Emissions	Base Location: San Juan Basin Well Type: Natural Gas																																																																																																																																																																																		
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If gas being captured, change scf/hr value or hours of event value.</p> <p>Assumptions:</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 30%;">Estimated Gas Flow Rate:</td> <td style="width: 20%;">0</td> <td style="width: 20%;">Scf/hr</td> <td style="width: 30%;"></td> </tr> <tr> <td>Combustion Efficiency:</td> <td>0.00</td> <td>Percent (%)</td> <td></td> </tr> <tr> <td>Event Duration:</td> <td>0.00</td> <td>Hours</td> <td>- Estimated 3 months before sales line</td> </tr> <tr> <td></td> <td>379.49</td> <td>Scf/lb-mol</td> <td>- Typical/Constant Conversion Value</td> </tr> </table> <p style="text-align: center;">* It is assumed that all produced natural gas is sent to a sales line after the well is completed.</p> <p style="text-align: center;">Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr</p> <p style="text-align: center;">** Multiply above equation by 0.05 if including 95% control efficiency</p> <p>Combusted Component Emissions:</p> <table border="1" style="width: 100%; border-collapse: collapse; text-align: center;"> <thead> <tr> <th>Component</th> <th>Mole % *</th> <th>Mole Weight lb/lb-mole</th> <th>Emissions Scf/hr</th> <th>Emissions lbs/hour</th> <th>Emissions Tons/Year</th> </tr> </thead> <tbody> <tr><td>Methane</td><td>88.9720</td><td>16.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethane</td><td>5.7920</td><td>30.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Propane</td><td>1.3650</td><td>44.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Butane</td><td>0.3700</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Butane</td><td>0.2610</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Pentane</td><td>0.1550</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Pentane</td><td>0.1020</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Other Pentanes</td><td>0.0000</td><td>70.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hexanes</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Heptanes</td><td>0.0930</td><td>100.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Octanes</td><td>0.0440</td><td>114.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nonanes</td><td>0.0160</td><td>128.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Decanes +</td><td>0.0050</td><td>142.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Benzene</td><td>0.0270</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Toluene</td><td>0.0190</td><td>92.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethylbenzene</td><td>0.0000</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>2,2,4 Trimethylpentane</td><td>0.0000</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Xylenes</td><td>0.0110</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Hexane</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nitrogen</td><td>0.0940</td><td>28.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Carbon Dioxide</td><td>2.5280</td><td>44.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hydrogen Sulfide</td><td>0.0000</td><td>34.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td colspan="6"> </td></tr> <tr> <td>VOC Subtotal</td> <td>2.7600</td> <td>1492.8</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>HAPS Subtotal</td> <td>0.2030</td> <td>546.9</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>Total</td> <td>100.1460</td> <td>1645.0</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> </tbody> </table>		Estimated Gas Flow Rate:	0	Scf/hr		Combustion Efficiency:	0.00	Percent (%)		Event Duration:	0.00	Hours	- Estimated 3 months before sales line		379.49	Scf/lb-mol	- Typical/Constant Conversion Value	Component	Mole % *	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year	Methane	88.9720	16.0	0.00	0.00	0.00	Ethane	5.7920	30.1	0.00	0.00	0.00	Propane	1.3650	44.1	0.00	0.00	0.00	i-Butane	0.3700	58.1	0.00	0.00	0.00	n-Butane	0.2610	58.1	0.00	0.00	0.00	i-Pentane	0.1550	72.2	0.00	0.00	0.00	n-Pentane	0.1020	72.2	0.00	0.00	0.00	Other Pentanes	0.0000	70.1	0.00	0.00	0.00	Hexanes	0.1460	86.2	0.00	0.00	0.00	Heptanes	0.0930	100.2	0.00	0.00	0.00	Octanes	0.0440	114.2	0.00	0.00	0.00	Nonanes	0.0160	128.3	0.00	0.00	0.00	Decanes +	0.0050	142.3	0.00	0.00	0.00	Benzene	0.0270	78.1	0.00	0.00	0.00	Toluene	0.0190	92.1	0.00	0.00	0.00	Ethylbenzene	0.0000	106.2	0.00	0.00	0.00	2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00	Xylenes	0.0110	106.2	0.00	0.00	0.00	n-Hexane	0.1460	86.2	0.00	0.00	0.00	Nitrogen	0.0940	28.0	0.00	0.00	0.00	Carbon Dioxide	2.5280	44.0	0.00	0.00	0.00	Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00							VOC Subtotal	2.7600	1492.8	0.00	0.00	0.00	HAPS Subtotal	0.2030	546.9	0.00	0.00	0.00	Total	100.1460	1645.0	0.00	0.00	0.00
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Flare Combustion GHG emissions:					
	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year	
	C1	88.97	0.00	0.00	0.00
	C2	5.79	0.00	0.00	0.00
	C3	1.37	0.00	0.00	0.00
	C4	0.63	0.00	0.00	0.00
	C5+	0.76	0.00	0.00	0.00
		CO₂ Total Emissions:	0.00	Tons/Year	
		N₂O Emissions:	0.00E+00	Tons/Year	
Flare Combustion Emissions:		Fuel Heating Value:	1028.00	btu/scf	
		lbs/mmBTU	lbs/hour	Tons/event	
	CO	0.00	0.00	0.00	AP-42 CH13.5-1
	NOx	0.000	0.00	0.00	AP-42 CH13.5-1
	SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Production Phase

Production Equipment Fugitive Component Emissions

Assumptions:

Components Counts:

	Fugitive Components				
Component *	Valves	Connectors	OE Lines	PR Valves	
Count	59	193	8	3	0
Emissions Factor (scf/hr) ^b	0.121	0.017	0.031	0.193	0.000

* Fugitive component counts for natural gas wells from Subpart W, Table W-1B

* Fugitive component counts for oil wells from Subpart W, Table W-1C

Annual Equipment Run Time: 8760 Hours/Year 379.49 Scf/lb-mol

Component	Mole % ^a	Mole Weight lb/lb-mol	Emissions Scf/Year ^b	Emissions lbs/Year	Emissions Tons/Year
Methane	88.9720	16.0	87,658.5	3,705.8	1.85
Ethane	5.7920	30.1	5,706.5	452.2	0.23
Propane	1.3650	44.1	1,344.8	156.3	0.08
i-Butane	0.3700	58.1	364.5	55.8	0.03
n-Butane	0.2610	58.1	257.1	39.4	0.02
i-Pentane	0.1550	72.2	152.7	29.0	0.01
n-Pentane	0.1020	72.2	100.5	19.1	0.01
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	143.8	32.7	0.02
Heptanes	0.0930	100.2	91.6	24.2	0.01
Octanes	0.0440	114.2	43.4	13.0	0.01
Nonanes	0.0160	128.3	15.8	5.3	0.00
Decanes +	0.0050	142.3	4.9	1.8	0.00
Benzene	0.0270	78.1	26.6	5.5	0.00
Toluene	0.0190	92.1	18.7	4.5	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	10.8	3.0	0.00
n-Hexane	0.1460	86.2	143.8	32.7	0.02
Nitrogen	0.0940	28.0	92.6	6.8	0.00
Carbon Dioxide	2.5280	44.0	2,490.7	288.8	0.14
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600			422.43	0.21
HAPS Subtotal	0.2030			45.72	0.02
Total	100.1460			4876.06	2.44

Calculation

$$\text{lb/hr} = (\text{Mol \%} * \text{SumSCF/yr}) / \text{scf/lb-mol}$$

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b Fugitive emission factors from Subpart W, Table W-1A

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Production Phase
Process Heater Emissions

Wellsite Heater Inventory:

	Heating Value (Mbtu/hr)	Fuel Consumption (MMscf/yr)	
Separator Heater	100	0.86	* Heater treater size based on industry standard

Annual Run Time:	8760	Hours/Year
Fuel Gas Heat Value:	1,020	Btu/scf (Standard heating value from AP-42)

Equations:

$$\text{Fuel Consumption (MMscf/yr)} = \frac{\text{Heater Size (MBtu/hr)} * 1,000 \text{ (Btu/MBtu)} * \text{Hours of Operation (hrs/yr)}}{\text{Fuel Heat Value (Btu/scf)} * 1,000,000 \text{ (scf/MMscf)}}$$

$$\text{NOx/CO/TOC Emissions (tons/yr)} = \frac{\text{AP-42 E.Factor (lbs/MMscf)} * \text{Fuel Consumption (MMscf/yr)} * \text{Fuel heating Value (Btu/scf)}}{2,000 \text{ (lbs/ton)} * 1,020 \text{ (Btu/scf - Standard Fuel Heating Value)}}$$

	Emission Factor (lb/MMscf)	Separator Heater Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year) ^c
<i>Criteria Pollutants & VOC</i>						
NOx ^a	100	0.0429	0.0000	0.0000	0.0000	0.0429
CO ^a	84.0	0.0361	0.0000	0.0000	0.0000	0.0361
VOC	5.5	0.0024	0.0000	0.0000	0.0000	0.0024
SO ₂ ^b	0.00	0.0000	0.0000	0.0000	0.0000	0.0000
TSP ^c	7.60	0.0033	0.0000	0.0000	0.0000	0.0033
PM ₁₀ ^c	7.60	0.0033	0.0000	0.0000	0.0000	0.0033
PM _{2.5} ^c	7.60	0.0033	0.0000	0.0000	0.0000	0.0033
<i>Hazardous Air Pollutants</i>						
Benzene ^d	2.10E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Toluene ^d	3.40E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Hexane ^d	1.80	0.0008	0.0000	0.0000	0.0000	0.0008
Formaldehyde ^d	7.50E-02	0.0000	0.0000	0.0000	0.0000	0.0000
<i>Greenhouse Gases</i>						
CO ₂ ^f	120,162	51.5989	0.0000	0.0000	0.0000	51.5989
CH ₄ ^f	2.27	0.0010	0.0000	0.0000	0.0000	0.0010
N ₂ O ^f	0.23	0.0001	0.0000	0.0000	0.0000	0.0001

a AP-42 Table 1.4-1, Emission Factors for Natural Gas Combustion, 7/98

b Assumes produced gas contains no sulfur

c AP-42 Table 1.4-2, Emission Factors for Natural Gas Combustion, 7/98 (All Particulates are PM_{1.0})

d AP-42 Table 1.4-3, Emission Factors for Organic Compounds from Natural Gas Combustion, 7/98

e Assumes maximum development scenario

f Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.

Kleinfelder, Inc. Wellsite Emissions			Base Location: San Juan Basin Well Type: Natural Gas			
Production Phase						
Atmospheric Oil Tank Flashing Emissions						
Assumptions:						
Production Estimate:		5	barrels/day			
Production Days:		365	Days/Year			
Flasing Gas-to-Oil Ratio:		75	Scf/bbl	379.49 Scf/lb-mol		
Control Efficiency:		0	Percent (%)			
Flashing Gas Composition:						
Component	Mole %	Mole Weight (lb/lb-mol)	Emissions (Uncontrolled) Scf/Year	Emissions (Uncontrolled) lbs/Year	Emissions (Uncontrolled) Tons/Year	Emissions (Controlled) Tons/Year
Methane	23.6778	16.043	32408.98875	1370.0951	0.6850	0.6850
Ethane	31.6716	30.07	43350.5025	3435.0038	1.7175	1.7175
Propane	27.0752	44.097	37059.18	4306.3023	2.1532	2.1532
i-Butane	2.3870	58.123	3267.20625	500.4080	0.2502	0.2502
n-Butane	6.1325	58.123	8393.859375	1285.6104	0.6428	0.6428
i-Pentane	0.9352	72.150	1280.055	243.3686	0.1217	0.1217
n-Pentane	1.5003	72.150	2053.535625	390.4256	0.1952	0.1952
Other Pentanes	0.6754	70.100	924.5016563	170.7754	0.0854	0.0854
Hexanes	2.2516	86.177	3081.8775	699.8523	0.3499	0.3499
Heptanes	0.7869	100.204	1077.069375	284.3992	0.1422	0.1422
Octanes	0.1469	114.231	201.069375	60.5243	0.0303	0.0303
Nonanes	0.0463	128.258	63.373125	21.4185	0.0107	0.0107
Decanes +	0.0105	142.285	14.371875	5.3886	0.0027	0.0027
Benzene	0.1540	78.120	210.7875	43.3917	0.0217	0.0217
Toluene	0.0709	92.130	97.044375	23.5598	0.0118	0.0118
Ethylbenzene	0.0034	106.160	4.65375	1.3019	0.0007	0.0007
2,2,4 Trimethylpentane	0.0253	78.120	34.629375	7.1286	0.0036	0.0036
Xylenes	0.0219	106.160	29.975625	8.3855	0.0042	0.0042
n-Hexane	0.9119	86.177	1248.163125	283.4408	0.1417	0.1417
Nitrogen	0.0000	28.013	0	0.0000	0.0000	0.0000
Carbon Dioxide	2.1907	44.010	2998.520625	347.7427	0.1739	0.1739
Hydrogen Sulfide	0.0000	34.080	0	0.0000	0.0000	0.0000
VOC Subtotal	43.14				4.17	4.17
HAPS Subtotal	1.19				0.18	0.18
Total	100.6753				6.7443	6.7443
Calculation:						
Scf/yr = (Mol% * scf/bbl * bbl/day * days/yr) / 100						
lb/yr = (scf/yr * mol wt.) / scf/lb-mol						
* Production and gas to oil ratio based on basin specific differences. Please see "Gas Stream Molar Ratios" tab and report for additional information.						

Kleinfelder, Inc. Wellsite Emissions	Base Location: San Juan Basin Well Type: Natural Gas									
Production Phase										
Wellsite Produced Water Tanks Venting										
Assumptions:										
Average Estimated Water Production:	800 Barrels Per Year									
Number of Water Tanks:	0 Tanks									
VOC Emissions Factor:	0.2620 lbs/bbl									
n-Hexane Emission Factor:	0.0220 lbs/bbl									
Benzene Emission Factor:	0.0070 lbs/bbl									
Calculations:										
<table border="1"><tr><td>VOC Emissions:</td><td>0</td><td>Tons/Year</td></tr><tr><td>Hexane Emissions:</td><td>0</td><td>Tons/Year</td></tr><tr><td>Benzene Emissions:</td><td>0</td><td>Tons/Year</td></tr></table>		VOC Emissions:	0	Tons/Year	Hexane Emissions:	0	Tons/Year	Benzene Emissions:	0	Tons/Year
VOC Emissions:	0	Tons/Year								
Hexane Emissions:	0	Tons/Year								
Benzene Emissions:	0	Tons/Year								
* Production conservatively based on estimated industry single well average										
* Emission factors based on only known lb/bbl factor, which was developed by the Colorado Department of Health and Environment (PS Memo 09-02).										

Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Production Phase
Truck Loading Emissions

AP - 42, Chapter 5.2

$$L_L = 12.46 \times S \times P \times M / T$$

L_L = Loading Loss Emission Factor (lbs VOC/1000 gal loaded)
S = Saturation Factor
P = True Vapor Pressure of the Loaded Liquid (psia)
M = Vapor Molecular Weight of the Loaded Liquid (lbs/lbmol)
T = Temperature of Loaded Liquid (°R)

$$\text{VOC Emissions (tpy)} = \frac{L_L (\text{lbs VOC}/1000 \text{ gal}) \times 42 \text{ gal/bbl} \times 365 \text{ days/year} \times \text{production (bbl/day)}}{1000 \text{ gal} \times 2000 \text{ lbs/ton}}$$

S ¹	P (psia) ²	M (lb/lbmol) ³	T (°F) ⁴	T (°R)	L _L (lb/1000 gal)	Production (bbl/day)	VOC (tpy)
0.6	4.20	66.00	50.00	509.67	4.07	5.0	0.16

Notes:

1. Saturation factor from AP-42, Table 5.2-1 (Submerged loading: dedicated normal service)
2. True vapor pressure is estimated from AP-42, Table 7.1-2 assuming an average daily temperature of either 40 or 50 deg F and an RVP of 10.0.
3. Molecular weight liquid vapor is estimated from AP-42, Table 7.1-2 assuming an RVP of 10.0.
4. Temperature based on the annual average temperature for basin location (either 40 or 50 degrees F based on options provided in AP-42 Table 7.1-2)

Kleinfelder, Inc. Wellsite Emissions	Base Location: San Juan Basin Well Type: Natural Gas																																																																																																											
Production Phase Pumpjack Unit Emissions																																																																																																												
<p>Assumptions:</p> <p style="text-align: center;">*Pumpjack engines only included at oil wells*</p> <table style="margin-left: auto; margin-right: auto;"> <tr> <td>Pumpjack Horsepower Rating:</td> <td>65.0</td> <td>Horsepower</td> </tr> <tr> <td>Load Factor:</td> <td>0.54</td> <td></td> </tr> <tr> <td>Brake Specific Fuel Consumption:</td> <td>8,000</td> <td>Btu/hp-hr</td> </tr> <tr> <td>Annual Operation:</td> <td>8,760</td> <td>Hours/Year</td> </tr> </table> <p>Equations:</p> <p style="text-align: center;"> Emissions (lbs/hr) = Emission Factor (g/hp-hr) * Power (hp) 453.6 g/lb </p> <table border="1" style="width: 100%; border-collapse: collapse; margin-top: 20px;"> <thead> <tr> <th style="text-align: center;">Pollutant</th> <th style="text-align: center;">Emission Factor ^a (lb/MMBtu)</th> <th style="text-align: center;">Emission Factor ^a (g/hp-hr)</th> <th style="text-align: center;">Emissions (lb/hr)</th> <th style="text-align: center;">Emissions (Tons/Year)</th> </tr> </thead> <tbody> <tr><td colspan="5"><i>Criteria Pollutants & VOC</i></td></tr> <tr><td>NOx</td><td></td><td style="text-align: center;">2.80</td><td style="text-align: center;">0.22</td><td style="text-align: center;">0.9490</td></tr> <tr><td>CO</td><td></td><td style="text-align: center;">4.80</td><td style="text-align: center;">0.37</td><td style="text-align: center;">1.6269</td></tr> <tr><td>VOC</td><td style="text-align: center;">0.12</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0337</td><td style="text-align: center;">0.1476</td></tr> <tr><td>PM₁₀ ^b</td><td style="text-align: center;">4.83E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">1.36E-02</td><td style="text-align: center;">5.94E-02</td></tr> <tr><td>PM_{2.5} ^b</td><td style="text-align: center;">4.83E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">1.36E-02</td><td style="text-align: center;">5.94E-02</td></tr> <tr><td>SO₂</td><td style="text-align: center;">5.88E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0002</td><td style="text-align: center;">0.0007</td></tr> <tr><td colspan="5"><i>Hazardous Air Pollutants</i></td></tr> <tr><td>Benzene</td><td style="text-align: center;">1.94E-03</td><td style="text-align: center;">-</td><td style="text-align: center;">5.45E-04</td><td style="text-align: center;">2.39E-03</td></tr> <tr><td>Toluene</td><td style="text-align: center;">9.63E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">2.70E-04</td><td style="text-align: center;">1.18E-03</td></tr> <tr><td>Ethylbenzene</td><td style="text-align: center;">1.08E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">3.03E-05</td><td style="text-align: center;">1.33E-04</td></tr> <tr><td>Xylenes</td><td style="text-align: center;">2.68E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">7.53E-05</td><td style="text-align: center;">3.30E-04</td></tr> <tr><td>Formaldehyde</td><td style="text-align: center;">5.52E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0155</td><td style="text-align: center;">0.0679</td></tr> <tr><td>n-Hexane</td><td style="text-align: center;">4.45E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">1.25E-04</td><td style="text-align: center;">5.47E-04</td></tr> <tr><td colspan="5"><i>Greenhouse Gases</i></td></tr> <tr><td>CO₂ ^c</td><td style="text-align: center;">117</td><td style="text-align: center;">-</td><td style="text-align: center;">32.82</td><td style="text-align: center;">144</td></tr> <tr><td>CH₄</td><td style="text-align: center;">0.002</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0006</td><td style="text-align: center;">0.0027</td></tr> <tr><td>N₂O</td><td style="text-align: center;">0.0002</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0001</td><td style="text-align: center;">0.0003</td></tr> </tbody> </table> <p style="margin-top: 20px;"> a AP-42 Table 3.2-3 Uncontrolled Emission Factors for 4-Stroke Rich-Burn Engines, 7/00; and Subpart JJJJ for NOX and CO emission rates. b PM = sum of PM filterable and PM condensable c Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu. </p> <p style="margin-top: 10px;"> - Network website for the 1999 National-Scale Air Toxics Assessment at http://www.epa.gov/ttn/atw/nata1999/nsata99.html </p>		Pumpjack Horsepower Rating:	65.0	Horsepower	Load Factor:	0.54		Brake Specific Fuel Consumption:	8,000	Btu/hp-hr	Annual Operation:	8,760	Hours/Year	Pollutant	Emission Factor ^a (lb/MMBtu)	Emission Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	<i>Criteria Pollutants & VOC</i>					NOx		2.80	0.22	0.9490	CO		4.80	0.37	1.6269	VOC	0.12	-	0.0337	0.1476	PM₁₀ ^b	4.83E-02	-	1.36E-02	5.94E-02	PM_{2.5} ^b	4.83E-02	-	1.36E-02	5.94E-02	SO₂	5.88E-04	-	0.0002	0.0007	<i>Hazardous Air Pollutants</i>					Benzene	1.94E-03	-	5.45E-04	2.39E-03	Toluene	9.63E-04	-	2.70E-04	1.18E-03	Ethylbenzene	1.08E-04	-	3.03E-05	1.33E-04	Xylenes	2.68E-04	-	7.53E-05	3.30E-04	Formaldehyde	5.52E-02	-	0.0155	0.0679	n-Hexane	4.45E-04	-	1.25E-04	5.47E-04	<i>Greenhouse Gases</i>					CO₂ ^c	117	-	32.82	144	CH₄	0.002	-	0.0006	0.0027	N₂O	0.0002	-	0.0001	0.0003
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Kleinfelder, Inc. Wellsite Emissions	Base Location: San Juan Basin Well Type: Natural Gas																								
Production Phase																									
Wellsite Dehydrator Emissions																									
<p>Assumptions:</p> <p>Number of Dehy Units: 0 Units</p> <p>Calculations:</p> <p>Calculations and specifications derived from Pinedale Anticline Final SEIS GRI-GLYCalc 4.0 operated with: 4 MMSCFD, 0.32 gpm glycol flow, average representative gas analysis, and 95% control efficiency</p> <p>Emissions:</p> <table border="1" data-bbox="553 987 1062 1478"> <thead> <tr> <th>Species</th><th>Total Project Emissions (tons/year)</th></tr> </thead> <tbody> <tr> <td>Total VOC</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Hazardous Air Pollutants</i></td></tr> <tr> <td>Benzene</td><td>0.000</td></tr> <tr> <td>Toluene</td><td>0.000</td></tr> <tr> <td>Ethylbenzene</td><td>0.000</td></tr> <tr> <td>Xylenes</td><td>0.000</td></tr> <tr> <td>n-Hexane</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Greenhouse Gases</i></td></tr> <tr> <td>CO₂</td><td>0.000</td></tr> <tr> <td>CH₄^a</td><td>0.000</td></tr> <tr> <td>N₂O</td><td>0.000</td></tr> </tbody> </table> <p>Note, no greenhouse gas emissions included for dehydrator in Pinedale EIS</p>		Species	Total Project Emissions (tons/year)	Total VOC	0.000	<i>Hazardous Air Pollutants</i>		Benzene	0.000	Toluene	0.000	Ethylbenzene	0.000	Xylenes	0.000	n-Hexane	0.000	<i>Greenhouse Gases</i>		CO₂	0.000	CH₄^a	0.000	N₂O	0.000
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: San Juan Basin
Well Type: Natural Gas

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks: 50 Trips/Location
 Light Duty Haul Trucks 0 Trips/Location Total Trips: 50 Trips

Heavy Duty Haul Trucks 2 Trips/Location
 Water Trucks 40 Trips/Location Total Trips: 42 Trips

* Miles and number of trips based on research and industry knowledge;
 please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (g/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NO_x	7.44E-02	6.25E-02	7.39E-03	7.39E-03	6.99E-02
CO	1.98E-02	1.66E-02	7.26E-02	7.26E-02	8.92E-02
VOC	3.16E-03	2.65E-03	3.54E-03	3.54E-03	6.19E-03
SO₂	4.57E-05	3.84E-05	2.83E-05	2.83E-05	6.67E-05
PM₁₀	4.22E-03	3.54E-03	1.94E-04	1.94E-04	3.74E-03
PM_{2.5}	4.09E-03	3.44E-03	1.79E-04	1.79E-04	3.61E-03
CO₂	1.88E+00	1.58E+00	1.13E+00	1.13E+00	2.70E+00
CH₄	7.61E-05	6.39E-05	4.56E-05	4.56E-05	1.10E-04
N₂O	1.52E-05	1.28E-05	9.13E-06	9.13E-06	2.19E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

c Assumes maximum development scenario

APPENDIX E

EMISSION INVENTORY FOR THE WILLISTON BASIN OIL WELL

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Location Selection:

Geography: Williston Basin
Well Type: Oil Well

- Choose geography/basin, and well type will automatically fill
- < Choose Uinta/Piceance Basin for deep gas wells with little condensate
- < Choose Upper Green River Basin for deep gas wells with dehydrators and higher condensate
- < Choose San Juan Basin for shallow gas wells with little to no condensate
- < Choose Williston Basin for deep oil wells with high gas
- < Choose Denver Basin for shallow oil wells with low gas

If the user wants to change any specifications, do so within the "Constants and References" tab, as all other tabs connect to it.

Pollutant:	Total Emissions (Tons per Year)								
	NO _x	CO	VOC	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O
Construction Phase:	0.47	0.29	0.04	0.0001	1.99	0.06	33.84	0.001	0.0003
Development Phase:	13.24	2.86	0.68	0.0002	4.84	0.44	1900.27	1.11	0.0498
Operation Phase:	1.87	4.85	16.83	0.0008	0.10	0.29	1222.32	15.44	0.5251
Total:	15.58	8.00	17.56	0.0011	6.93	0.79	3156.43	16.55	0.5751

Pollutant:	Total Emissions (Tons per Year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	HAPs
Construction Phase:	0.00	0.00	0.00	0.00	0.00	0.00
Development Phase:	1.36	0.95	0.0000	0.55	7.31	10.18
Operation Phase:	0.16	0.02	0.00077	0.014	0.59	0.85
Total:	1.52	0.98	0.00077	0.57	7.89	11.02

CO ₂ equivalent (Global Warming Potential)	
Total TPY:	3682.34
CO ₂ equivalent conversions:	
CO ₂	1.00
CH ₄	21.00
N ₂ O	310.00

H ₂ S Emissions	
Total TPY:	0.00

* If H₂S in gas, input value in "Gas Stream Molar Ratios" tab, and potential emissions will calculate here. Current assumption is no H₂S in gas stream.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Road Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	4	Days/Location	(Typical Value)
	48.0	Dozer Hours/Location	(Typical Value)
	48.0	Backhoe Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅ (AP-42 Table 11.9-1, 7/98)		
PM _{2.5} Multiplier:	0.105 * TSP (AP-42 Table 11.9-1, 7/98)		

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98 & 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0473	1.97	0.0473	0.0946
PM₁₅	0.50	0.0120	0.50	0.0120	0.0241
PM₁₀	0.38	0.0090	0.38	0.0090	0.0181
PM_{2.5}	0.21	0.0050	0.05	0.0013	0.0062

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase
Road Grader Particulate Matter

Assumptions:

Grading Length:	6.00	miles	(Typical Value)
Construction Schedule:	3	Days/Location	(Typical Value)
	12	Hours/Day	(Typical Value)
	36	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	
Average Grader Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 16.12 lbs TSP/Location

Emissions = 7.71 lbs PM₁₅/Location

Grader Construction Emissions			
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	16.12	0.45	8.06E-03
PM₁₅	7.71	0.21	3.86E-03
PM₁₀	4.63	0.13	2.31E-03
PM_{2.5}	0.50	0.01	2.50E-04

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Well Pad Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location (Dozer)	(Typical Value)
	70	Hours/Location (Back Hoe)	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase
Well Pad Grader Particulate Matter

Assumptions:

Construction Schedule:	4.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	40	Hours/Location	(Typical Value)
Watering Control Efficiency	50	Percent (%)	(Typical Value)
Average Grader Speed	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
Distance Graded	2.84	Miles/Location	(Typical Value)
PM ₁₀ Multiplier	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 7.63 lbs TSP/well pad

Emissions = 3.65 lbs PM₁₅/well pad

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	7.63	0.19	0.0038
PM₁₅	3.65	0.09	0.0018
PM₁₀	2.19	0.05	0.0011
PM_{2.5}	0.24	0.01	0.0001

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Pipeline Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Pipeline Grader Particulate Matter

Assumptions:

Distance Graded:	12.50	Miles/Location	(Typical Value)
Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Mean Vehicle Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs) = $0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs) = $0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions = 33.58 lbs TSP/well

Emissions = 16.07 lbs PM₁₅/well

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	33.58	0.48	0.0168
PM₁₅	16.07	0.23	0.0080
PM₁₀	9.64	0.14	0.0048
PM_{2.5}	1.04	0.01	0.0005

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Heavy Diesel Truck Trips:

Road Construction:	7	Trips			
Well Pad Construction:	8	Trips	Total Trips:	21	Trips
Pipeline Construction:	6	Trips			

Light Duty Pickup Truck Trips:

Road Construction:	16	Trips			
Well Pad Construction:	28	Trips	Total Trips:	100	Trips
Pipeline Construction:	56	Trips			

* All assumptions above are based on typical industry values

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a	Emissions	E. Factor ^b	Emissions	Emissions
	(lb/mile)	(Tons/Location)	(lb/mile)	(Tons/Location)	(Tons/Location)
NOx	7.44E-02	3.12E-02	7.39E-03	1.48E-02	4.60E-02
CO	1.98E-02	8.32E-03	7.26E-02	1.45E-01	1.54E-01
VOC	3.16E-03	1.33E-03	3.54E-03	7.08E-03	8.41E-03
SO2	4.57E-05	1.92E-05	2.83E-05	5.66E-05	7.58E-05
PM10	4.22E-03	1.77E-03	1.94E-04	3.88E-04	2.16E-03
PM2.5	4.09E-03	1.72E-03	1.79E-04	3.58E-04	2.08E-03
CO2	1.88	0.79	1.13	2.25	3.04
CH4	7.61E-05	3.19E-05	4.56E-05	9.13E-05	1.23E-04
N2O	1.52E-05	6.39E-06	9.13E-06	1.83E-05	2.46E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Construction Heavy Equipment Tailpipe Emissions

Assumptions:

Fuel and Engine:

Brake Specific Fuel Consumption, Avg. (BSFC) 8250 btu/hp-hr (Typical Value)
Diesel Higher Heating Value (HHV) 0.138 mmBtu/Gallon (Typical Value)

Trackhoe:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 100 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Tractors/Loaders/Backhoes)

Dozer:

Working Hours 188 Total Hours (Typical Value)
Rated Horsepower 140 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Crawler Tractor/Dozers)

Grader:

Working Hours 130 Total Hours (Typical Value)
Rated Horsepower 250 (Estimate)
Load Factor 0.59 (Default LF from NONROAD model for Graders)

Total Horsepower Hours: 45795.8 Hp-hrs (Sum of all horsepower above)
Total Fuel Usage: 2737.79 Gallons Diesel Fuel

Equations:

Total Fuel Usage: (btu-hp-hr * hp-hrs) / Mmbtu-gal) / 1,000,000
Emissions (tons/year/pad) = $\frac{\text{Emission Factor (g/mile)} * \text{Trip Distance (miles)} * \text{Load Factor}}{453.6 \text{ (g/lb)} * 2000 \text{ (lb/tons)}}$

Heavy Const. Vehicles	Backhoe			Dozer			Grader		
	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
NOx	8.38	1.09E+00	1.02E-01	8.38	1.53E+00	1.43E-01	8.38	2.72E+00	1.77E-01
CO	2.7	3.51E-01	3.30E-02	2.7	4.92E-01	4.62E-02	2.7	8.78E-01	5.71E-02
VOC ^b	0.68	8.84E-02	8.31E-03	0.68	1.24E-01	1.16E-02	0.68	2.21E-01	1.44E-02
PM₁₀	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03
PM_{2.5}	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03

Heavy Const. Vehicles	Total Emissions ^c (tons/yr)
NOx	0.42
CO	0.14
VOC	0.03
PM₁₀	0.02
PM_{2.5}	0.02

Greenhouse Gas Emissions:

	Diesel EF kg/mmbtu	Emissions lbs	Emissions Tons
CO ₂	73.96	61604.19	30.80
CH ₄	0.003	2.50	0.0012
N ₂ O	0.0006	0.50	0.0002

a From Table A-4 of Exhaust and Crankcase Emission Factors for NONROAD Engine Modeling - Compression Ignition, EPA-420-R-10-018, July 2010.

b Emission Factor represents total Hydrocarbon Emissions

c Converted from emission factor for Distillate Fuel Oil #2 (diesel) as listed in Table C-1 to Subpart C of Part 98 - Default Emission Factors and High Heat Values for Various Types of Fuel.

Listed Factor:

73.96 kg CO₂/mmBtu
393 hp-hr = mmBtu
188.2 g CO₂/hp-hr

Kleinfelder, Inc. Wellsite Emissions		Base Location: Williston Basin Well Type: Oil Well													
Construction Phase															
Wind Erosion Fugitive Dust															
Assumptions:															
Threshold Friction Velocity (U _t)	1.02 1.33	m/s (2.28 mph) for well pads (AP-42 Table 13.2.5-2 Overburden - Western Surface Coal Mine) m/s (2.97 mph) for roads (AP-42 Table 13.2.5-2 Roadbed material)													
Initial Disturbance Area															
Total Access Road/ROW Area Per Location:	976,800	Square Meters	(Typical Value)												
Total Well Pad Area Disturbed Per Location:	50,000	Square Meters	(Typical Value)												
Total Area Disturbed Per Location:	1,026,800	Square Meters	(Typical Value)												
Exposed Surface Type	Flat														
Meteorological Data	2002 Grand Junction (obtained from NCDC website)														
Fastest Mile Wind Speed:	45	miles/hour	(Typical Value)												
Fastest Mile Wind Speed (U ₁₀ ⁺)	20.12	meters/sec (45 mph) reported as fastest 2-minute wind speed for Grand Junction (2002)													
Number soil of disturbances	1.00	for well pads (Assumption, disturbance at construction and reclamation) constant for dirt roads													
Equations (AP-42 13.2.5.2 Industrial Wind Erosion)															
Friction Velocity U* = 0.053 U ₁₀ ⁺															
Erosion Potential P (g/m ² /period) = 58*(U*-U _t *) ² + 25*(U*-U _t *) for U*>U _t *, P = 0 for U*< U _t *															
Emissions (tons/year) = Erosion Potential(g/m ² /period)*Disturbed Area(m ²)*Disturbances/year*(k)/(453.6 g/lb)/2000 lbs/ton/Develop Period															
<table><tr><th colspan="3">Particle Size Multiplier (k)</th></tr><tr><th>30 μm</th><th><10 μm</th><th><2.5 μm</th></tr><tr><td>1.0</td><td>0.5</td><td>0.075</td></tr></table>				Particle Size Multiplier (k)			30 μm	<10 μm	<2.5 μm	1.0	0.5	0.075			
Particle Size Multiplier (k)															
30 μm	<10 μm	<2.5 μm													
1.0	0.5	0.075													
<table><tr><th>Maxium U₁₀⁺ Wind Speed (m/s)</th><th>Maximum U* Friction Velocity m/s</th><th>Well U_t* Threshold Velocity^a m/s</th><th>Well Pad Erosion Potential g/m²</th><th>Road U_t* Threshold Velocity^a m/s</th><th>Road Erosion Potential g/m²</th></tr><tr><td>20.12</td><td>1.07</td><td>1.02</td><td>1.28</td><td>1.33</td><td>0.00</td></tr></table>				Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²	20.12	1.07	1.02	1.28	1.33	0.00
Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²										
20.12	1.07	1.02	1.28	1.33	0.00										
Wind Erosion Emissions															
<table><tr><th>Particulate Species</th><th>Well Pad (tons/year)</th><th>Roads/Pipelines (tons/year)</th></tr><tr><td>TSP</td><td>7.05E-02</td><td>0.00E+00</td></tr><tr><td>PM₁₀</td><td>3.52E-02</td><td>0.00E+00</td></tr><tr><td>PM_{2.5}</td><td>5.28E-03</td><td>0.00E+00</td></tr></table>				Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)	TSP	7.05E-02	0.00E+00	PM ₁₀	3.52E-02	0.00E+00	PM _{2.5}	5.28E-03	0.00E+00
Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)													
TSP	7.05E-02	0.00E+00													
PM ₁₀	3.52E-02	0.00E+00													
PM _{2.5}	5.28E-03	0.00E+00													

Kleinfelder, Inc.				Base Location: Williston Basin					
Website Emissions				Well Type: Oil Well					
Construction, Development, and Production Phase									
Construction, Development, and Operations Traffic Fugitive Dust Emissions									
Assumptions:									
				Round Trip Miles	40				
				Round Trip (Paved) Miles	16				
				Round Trip (Un-Paved) Miles	24				
				Precipitation Days (P)	45				
Unpaved Calculation AP-42, Chapter 13.2.2 November 2006				$E (PM_{10}) / VMT = 1.5 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$ $E (PM_{2.5}) / VMT = 0.15 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
Silt Content (S)				8.5		AP 42 13.2.2-1 Mean Silt Content Construction Sites			
Paved Calculation AP-42, Chapter 13.2.1 January 2011				$E (PM_{10}) / VMT = 0.0022 * (sL)^{0.91} * (W)^{0.42} * (1-(P/(365*4)))$ $E (PM_{2.5}) / VMT = 0.00054 * (sL)^{0.91} * (W)^{0.42} * (1-(P/(365*4)))$					
Silt Loading (sL)				0.6		AP-42 Table 13.2.1-2 baseline low volume roads			
Unpaved Calculations:									
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	3.09	1558.9	0.8	0.3	155.9	0.1
	Light Duty Pickup Trucks	5,000	100	0.89	2131.8	1.1	0.1	213.2	0.1
	Total:				3690.67	1.85		369.07	0.18
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	0.0576	19.4	0.0097	0.014	4.8	0.0024
	Light Duty Pickup Trucks	5,000	100	0.0034	5.5	0.0027	0.001	1.3	0.0007
	Total:				24.8	0.0		6.1	0.0
Unpaved Calculations:									
Development Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	84	0.89	1790.7	0.9	0.1	179.1	0.1
	Light Duty Haul Trucks	7,500	11	1.07	281.4	0.1	0.1	28.1	0.0
	Heavy Duty Haul Trucks	80,000	67	3.09	4973.6	2.5	0.3	497.4	0.2
	Water Trucks	70,000	24	2.91	1677.7	0.8	0.3	167.8	0.1
	Total:				8723.41	4.36		872.34	0.44
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips						
	Light Duty Pickup Trucks	5000	84	0.00	4.6	0.0	0.0	1.1	0.0006
	Light Duty Haul Trucks	7500	11	0.01	0.9	0.0	0.0	0.2	0.0001
	Heavy Duty Haul Trucks	80000	67	0.06	61.8	0.0	0.0	15.2	0.0076
	Water Trucks	70,000	24	0.05	19.3	0.0	0.0	4.7	0.0024
	Total:				86.6	0.0		21.2	0.0
Unpaved Calculations:									
Production Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	50	0.89	1065.89	0.53	0.0888	106.59	0.0533
	Light Duty Haul Trucks	7,500	0	1.07	0.00	0.00	0.1066	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	3.09	148.47	0.07	0.3093	14.85	0.0074
	Water Trucks	70,000	40	2.91	2796.14	1.40	0.2913	279.61	0.1398
	Total:				4010.50	2.01		401.05	0.20
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	50	0.00	2.73	0.0014	0.0008	0.67	0.0003
	Light Duty Haul Trucks	7,500	0	0.01	0.00	0.0000	0.0013	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	0.06	1.84	0.0009	0.0141	0.45	0.0002
	Water Trucks	70,000	40	0.05	32.18	0.0161	0.0123	7.90	0.0039
	Total:				36.75	0.02		9.02	0.00
Annual Total					Unpaved Roads PM ₁₀ (tons) 8.21			Unpaved Roads PM _{2.5} (tons) 0.8	
					Paved Roads PM ₁₀ 0.1			Paved Roads PM _{2.5} 0.0	
					Total:			0.8	
Total:					8.3		0.8		

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Development Phase
Drill Rig Emissions

Assumptions:

Parameter	Value
Days of Operation	18 (Typical Value)
Hours of Operation	432 (Typical Value)
Diesel Fuel Sulfur Content	0.000015 (Typical Value)

Parameter	Value	Units
BSFC (Avg.)	8250 (Typical Value)	btu/hp-hr
Diesel HHV	0.138 (Typical Value)	mmbtu/gal

Engine	HP *	Load Factor	Run time (hrs)	Total Hp-hrs
Vertical Drill Rig Engine	850	0.42	144	51408
Horizontal Drill Rig Engine 1	2,100	0.59	288	356832
Horizontal Drill Rig Engine 2	2,100	0.59	432	535248
Drill Rig Generator	350	0.42	432	63504
Trailers Generator	150	0.42	432	27216
Air Compressor	550	0.42	144	33264
Air Compressor	550	0.42	144	33264
Air Compressor	550	0.42	144	33264
Air Compressor	550	0.42	144	33264
Air Compressor Booster	650	0.42	144	39312
Forklift	120	0.42	144	7257.6
Aerial Lift	50	0.42	16	336
Frontend loader	150	0.42	16	1008
Dozer	175	0.60	9	945

Total HP 8,895

Total: 1,216,123 Hp-hrs

Fuel Usage: 72,703 Gallons of Diesel Total Fuel Usage: (btu/hp-hr * hp-hrs) * gal/btu

Greenhouse Gasses:

	Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location
CO2	73.96	1635919.59	817.96
CH4	0.003	66.36	0.03
N2O	0.0006	13.27	0.01

Greenhouse gas emission factors from Subpart C, Table C-1 and C-2

Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)
Vertical Drill Rig Engine	51408	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Horizontal Drill Rig Engine 1	356832	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Horizontal Drill Rig Engine 2	535248	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Drill Rig Generator	63504	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Trailers Generator	27216	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
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Air Compressor	33264	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor Booster	39312	1.3272	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Forklift	7257.6	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Aerial Lift	336	5.0000	6.9000	0.8000	0.7760	1.27E-05	1.8000	7.76E-04	2.81E-04	1.93E-04
Frontend loader	1008	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Dozer	945	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04

Engine	CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)
Vertical Drill Rig Engine	0.04331	0.23234	0.00746	0.00723	7.20E-07	0.00927	0.00016	0.00006	0.00004
Horizontal Drill Rig Engine 1	0.30059	1.61269	0.05176	0.05021	4.99E-06	0.06435	0.00114	0.00041	0.00028
Horizontal Drill Rig Engine 2	0.45089	2.41904	0.07765	0.07532	7.49E-06	0.09653	0.00171	0.00062	0.00043
Drill Rig Generator	0.18900	0.58661	0.02814	0.02730	8.89E-07	0.04760	0.00020	0.00007	0.00005
Trailers Generator	0.08100	0.25140	0.01206	0.01170	3.81E-07	0.02040	0.00009	0.00003	0.00002
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor	0.03089	0.15896	0.00483	0.00468	4.66E-07	0.00600	0.00011	0.00004	0.00003
Air Compressor Booster	0.05751	0.17767	0.00570	0.00553	5.50E-07	0.00709	0.00013	0.00005	0.00003
Forklift	0.02160	0.06704	0.00322	0.00312	1.02E-07	0.00544	0.00002	0.00001	0.00001
Aerial Lift	0.00185	0.00256	0.00030	0.00029	4.70E-09	0.00067	0.00000	0.00000	0.00000
Frontend loader	0.00300	0.00931	0.00045	0.00043	1.41E-08	0.00076	0.00000	0.00000	0.00000
Dozer	0.00281	0.00873	0.00042	0.00041	1.32E-08	0.00071	0.00000	0.00000	0.00000
Total:	1.27513	6.00321	0.20645	0.20026	0.00002	0.27680	0.00389	0.00141	0.00097

Emission Factors

- Drill rig emission factors based on Tier II engines
- All other engine emission factors based on Tier 0 engines (typical values)
- HAP emission factors from AP-42 Volume I, Large Stationary Diesel Engines Table 3.4-3

Calculations:

ton/year: (Total hp-hr * g/hp-hr) * lb-gram / lb-ton

*** Drill rig horsepower developed based on:**

- 1 Williston Basin: 2,100 from Jonah, Wyoming RMP
- 2 San Juan Basin: 2,100 from River Valley RMP
- 3 Upper Green River Basin: 2,100 from Jonah, Wyoming RMP
- 4 Denver Basin: 2,950 from River Valley RMP
- 5 Uintah Basin: 2,952 from River Valley RMP

Note, runtime for each drilling event is based on research and industry experience dependent upon each basi

Kleinfelder, Inc. Wellsite Emissions	Base Location: Williston Basin Well Type: Oil Well																																																																									
Development Phase																																																																										
Conductor Pipe Set Emissions																																																																										
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Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton * Rig engine emission rates are based on a Tier II engine and rig generator emission rates are based on a Tier 0 engine. * All days, hours, and HP values above are based on typical industry values																																																																										

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Development Phase

Hydraulic Fracturing Flowback Emissions

Assumptions:

Estimated Frac flowback Rate: 10,000 Scf/hr
Combustion Efficiency: 95.00 Percent (%)
Event Duration: 100.00 Hours
 379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Venting duration based on research and industry knowledge; please see report for additional information.
 * Venting control based on Subpart OOOO requirements of 95% minimum control.
 Control efficiency can be deleted if applicable.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr
 ** Multiply above equation by 0.02 if including 98% control efficiency

Un-combusted Componet Emissions:

Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	444.86	18.81	0.94
Ethane	5.7920	30.1	28.96	2.29	0.11
Propane	1.3650	44.1	6.83	0.79	0.04
i-Butane	0.3700	58.1	1.85	0.28	0.01
n-Butane	0.2610	58.1	1.31	0.20	0.01
i-Pentane	0.1550	72.2	0.78	0.15	0.01
n-Pentane	0.1020	72.2	0.51	0.10	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.73	0.17	0.01
Heptanes	0.0930	100.2	0.47	0.12	0.01
Octanes	0.0440	114.2	0.22	0.07	0.00
Nonanes	0.0160	128.3	0.08	0.03	0.00
Decanes +	0.0050	142.3	0.03	0.01	0.00
Benzene	0.0270	78.1	0.14	0.03	0.00
Toluene	0.0190	92.1	0.10	0.02	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.06	0.02	0.00
n-Hexane	0.1460	86.2	0.73	0.17	0.01
Nitrogen	0.0940	28.0	9.40	0.69	0.03
Carbon Dioxide	2.5280	44.0	252.80	29.32	1.47
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600	1492.8	13.80	2.14	0.11
HAPS Subtotal	0.2030	546.9	1.02	0.23	0.01
Total	100.1460	1645.0	749.82	53.26	2.66

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	8452.34	980.23	49.01
C2	5.79	550.24	63.81	3.19
C3	1.37	129.68	15.04	0.75
C4	0.63	59.95	6.95	0.35
C5+	0.76	72.58	8.42	0.42

CO₂ Total Emissions: 53.72 Tons/Event
N₂O Emissions: 1.13E-04 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.37	3.80	0.19	AP-42 CH13.5-1
NOx	0.068	0.70	0.03	AP-42 CH13.5-1
SO ₂	-	0.00	0.00	*Based on H2s 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions	Base Location: Williston Basin Well Type: Oil Well																																												
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Circulation Pump	450	0.42	24	4536																																									
Cement Pump Trucks	500	0.42	8	1680																																									
<p>Total Horsepower: 1,500 (Typical Value)</p> <p>Total: 11,760 Hp-hrs</p> <p>Fuel Usage: 724 Gallons of Diesel Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)</p>	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>16298.85</td><td>8.15</td></tr><tr><td>CH4</td><td>0.003</td><td>0.66</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.13</td><td>0.00</td></tr></table>		Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	16298.85	8.15	CH4	0.003	0.66	0.00	N2O	0.0006	0.13	0.00																												
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Engine		CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Formaldehyde (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)																																			
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Total: 0.01436 0.06369 0.00221 0.00214 0.00308 0.00004 0.00000 0.00001 0.00001																																													
Emission Factors - Engine emission factors based on Tier II engines (typical values)																																													
Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																													

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Development Phase
Well Venting During Workover Events

Assumptions:

Significant gas venting only occurs on natural gas wells.

Estimated Venting Rate: 5,000 Scf/Event (Typical Value)
Combustion Efficiency: 0.00 Percent (%)
Event Quantity: 1.00 Event - Assumed one event
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Vented quantity based on research and industry knowledge; please see report for additional information.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf-lb-mol)
** Multiply above equation by 0.02 if including 98% control efficiency

Component	Mole %	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Event
Methane	88.9720	16.0	4448.60	188.07	0.0940
Ethane	5.7920	30.1	289.60	22.95	0.0115
Propane	1.3650	44.1	68.25	7.93	0.0040
i-Butane	0.3700	58.1	18.50	2.83	0.0014
n-Butane	0.2610	58.1	13.05	2.00	0.0010
i-Pentane	0.1550	72.2	7.75	1.47	0.0007
n-Pentane	0.1020	72.2	5.10	0.97	0.0005
Other Pentanes	0.0000	70.1	0.00	0.00	0.0000
Hexanes	0.1460	86.2	7.30	1.66	0.0008
Heptanes	0.0930	100.2	4.65	1.23	0.0006
Octanes	0.0440	114.2	2.20	0.66	0.0003
Nonanes	0.0160	128.3	0.80	0.27	0.0001
Decanes +	0.0050	142.3	0.25	0.09	0.0000
Benzene	0.0270	78.1	1.35	0.28	0.0001
Toluene	0.0190	92.1	0.95	0.23	0.0001
Ethylbenzene	0.0000	106.2	0.00	0.00	0.0000
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.0000
Xylenes	0.0110	106.2	0.55	0.15	0.0001
n-Hexane	0.1460	86.2	7.30	1.66	0.0008
Nitrogen	0.0940	28.0	4.70	0.35	0.0002
Carbon Dioxide	2.5280	44.0	126.40	14.66	0.0073
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.0000

VOC Subtotal	2.7600	1492.8	138.00	21.44	0.0107
HAPS Subtotal	0.2030	546.9	10.15	2.32	0.0012
Total	100.1460	1645.0	5007.30	247.46	0.1237

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	0.00	0.00	0.00
C2	5.79	0.00	0.00	0.00
C3	1.37	0.00	0.00	0.00
C4	0.63	0.00	0.00	0.00
C5+	0.76	0.00	0.00	0.00

CO₂ Total Emissions: 0.00 Tons/Event
N₂O Emissions: 5.67E-07 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NOx	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.000	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Development Phase

Wellsite Development Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks: 84 Trips/Location
 Light Duty Haul Trucks: 11 Trips/Location Total Trips: 95 Trips

Heavy Duty Haul Trucks: 67 Trips/Location
 Water Trucks: 24 Trips/Location Total Trips: 91 Trips

* Miles and number of trips based on research and industry knowledge;
 please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NO_x	7.44E-02	1.35E-01	1.98E-02	1.41E-01	2.77E-01
CO	1.98E-02	3.60E-02	3.16E-03	3.76E-02	7.37E-02
VOC	3.16E-03	5.75E-03	4.57E-05	6.00E-03	1.18E-02
SO₂	4.57E-05	8.32E-05	4.22E-03	8.68E-05	1.70E-04
PM₁₀	4.22E-03	7.68E-03	4.09E-03	8.02E-03	1.57E-02
PM_{2.5}	4.09E-03	7.44E-03	1.88E+00	7.77E-03	1.52E-02
CO₂	1.88E+00	3.41E+00	7.61E-05	3.56E+00	6.98E+00
CH₄	7.61E-05	1.38E-04	1.52E-05	1.45E-04	2.83E-04
N₂O	1.52E-05	2.77E-05	0.00E+00	2.89E-05	5.66E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite for calendar year 2012.

c Assumes maximum development scenario

Kleinfelder, Inc. Wellsite Emissions			Base Location: Williston Basin Well Type: Oil Well		
Development Phase					
Wellhead Gas Combustion					
**Wellhead gas combustion only for Williston Basin wells, due to the regularity of of pit flares combusting all gas coming from the wellhead. If gas being captured, change scf/hr value or hours of event value.					
Assumptions:					
Estimated Gas Flow Rate:	6,875	Scf/hr			
Combustion Efficiency:	95.00	Percent (%)			
Event Duration:	2190.00	Hours	- Estimated 3 months before sales line		
	379.49	Scf/lb-mol	- Typical/Constant Conversion Value		
* Gas flow rate based on estimated gas to oil ratio and estimated liquid production					
- GOR of 1100 scf/bbl and 150 bbl/day production: 1100 scf/bbl *150 bbl-d / 24 = 6,875 scf/hr)					
* Combustion control percent based on industry knowledge of standard Williston Basin pit flares					
Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr					
** Multiply above equation by 0.05 if including 95% control efficiency					
Combusted Componet Emissions:					
Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	305.84	12.93	14.16
Ethane	5.7920	30.1	19.91	1.58	1.73
Propane	1.3650	44.1	4.69	0.55	0.60
i-Butane	0.3700	58.1	1.27	0.19	0.21
n-Butane	0.2610	58.1	0.90	0.14	0.15
i-Pentane	0.1550	72.2	0.53	0.10	0.11
n-Pentane	0.1020	72.2	0.35	0.07	0.07
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.50	0.11	0.12
Heptanes	0.0930	100.2	0.32	0.08	0.09
Octanes	0.0440	114.2	0.15	0.05	0.05
Nonanes	0.0160	128.3	0.06	0.02	0.02
Decanes +	0.0050	142.3	0.02	0.01	0.01
Benzene	0.0270	78.1	0.09	0.02	0.02
Toluene	0.0190	92.1	0.07	0.02	0.02
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.04	0.01	0.01
n-Hexane	0.1460	86.2	0.50	0.11	0.12
Nitrogen	0.0940	28.0	6.46	0.48	0.52
Carbon Dioxide	2.5280	44.0	173.80	20.16	22.07
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00
VOC Subtotal	2.7600	1492.8	9.49	1.47	1.61
HAPS Subtotal	0.2030	546.9	0.70	0.16	0.17
Total	100.1460	1645.0	515.50	36.61	40.09

Flare Combustion GHG emissions:					
	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year	
C1	88.97	5810.98	673.91	737.93	
C2	5.79	378.29	43.87	48.04	
C3	1.37	89.15	10.34	11.32	
C4	0.63	41.21	4.78	5.23	
C5+	0.76	49.90	5.79	6.34	
CO ₂ Total Emissions:				808.86	Tons/Year
N ₂ O Emissions:				1.71E-03	Tons/Year
Flare Combustion Emissions:					
Fuel Heating Value:		1028.00	btu/scf		
	lbs/mmBTU	lbs/hour	Tons/event		
CO	0.37	2.61	2.86	AP-42 CH13.5-1	
NOx	0.068	0.48	0.53	AP-42 CH13.5-1	
SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight	

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Production Phase

Production Equipment Fugitive Component Emissions

Assumptions:

Components Counts:

	Fugitive Components				
Component *	Valves	Flanges	Connectors	OE Lines	Other
Count	24	44	38	0	0
Emissions Factor (scf/hr) ^b	0.050	0.003	0.007	0.050	0.300

* Fugitive component counts for natural gas wells from Subpart W, Table W-1B

* Fugitive component counts for oil wells from Subpart W, Table W-1C

Annual Equipment Run Time:

8760

Hours/Year

379.49 Scf/lb-mol

Component	Mole % ^a	Mole Weight lb/lb-mol	Emissions Scf/Year ^b	Emissions lbs/Year	Emissions Tons/Year
Methane	88.9720	16.0	12,454.7	526.5	0.26
Ethane	5.7920	30.1	810.8	64.2	0.03
Propane	1.3650	44.1	191.1	22.2	0.01
i-Butane	0.3700	58.1	51.8	7.9	0.00
n-Butane	0.2610	58.1	36.5	5.6	0.00
i-Pentane	0.1550	72.2	21.7	4.1	0.00
n-Pentane	0.1020	72.2	14.3	2.7	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	20.4	4.6	0.00
Heptanes	0.0930	100.2	13.0	3.4	0.00
Octanes	0.0440	114.2	6.2	1.9	0.00
Nonanes	0.0160	128.3	2.2	0.8	0.00
Decanes +	0.0050	142.3	0.7	0.3	0.00
Benzene	0.0270	78.1	3.8	0.8	0.00
Toluene	0.0190	92.1	2.7	0.6	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	1.5	0.4	0.00
n-Hexane	0.1460	86.2	20.4	4.6	0.00
Nitrogen	0.0940	28.0	13.2	1.0	0.00
Carbon Dioxide	2.5280	44.0	353.9	41.0	0.02
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600			60.02	0.03
HAPS Subtotal	0.2030			6.50	0.00
Total	100.1460			692.80	0.35

Calculation

$$\text{lb/hr} = (\text{Mol \%} * \text{SumSCF/yr}) / \text{scf/lb-mol}$$

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b Fugitive emission factors from Subpart W, Table W-1A

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Production Phase
Process Heater Emissions

Wellsite Heater Inventory:

Heater Treater	Heating Value (Mbtu/hr)	Fuel Consumption (MMscf/yr)	
	750	6.44	* Heater treater size based on industry standard

Annual Run Time:	8760	Hours/Year
Fuel Gas Heat Value:	1,020	Btu/scf (Standard heating value from AP-42)

Equations:

$$\text{Fuel Consumption (MMscf/yr)} = \frac{\text{Heater Size (MBtu/hr)} * 1,000 \text{ (Btu/MBtu)} * \text{Hours of Operation (hrs/yr)}}{\text{Fuel Heat Value (Btu/scf)} * 1,000,000 \text{ (scf/MMscf)}}$$

$$\text{NOx/CO/TOC Emissions (tons/yr)} = \frac{\text{AP-42 E.Factor (lbs/MMscf)} * \text{Fuel Consumption (MMscf/yr)} * \text{Fuel heating Value (Btu/scf)}}{2,000 \text{ (lbs/ton)} * 1,020 \text{ (Btu/scf - Standard Fuel Heating Value)}}$$

	Emission Factor (lb/MMscf)	Heater Treater Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year) ^e
<i>Criteria Pollutants & VOC</i>						
NOx ^a	100	0.3221	0.0000	0.0000	0.0000	0.3221
CO ^a	84.0	0.2705	0.0000	0.0000	0.0000	0.2705
VOC	5.5	0.0177	0.0000	0.0000	0.0000	0.0177
SO ₂ ^b	0.00	0.0000	0.0000	0.0000	0.0000	0.0000
TSP ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
PM ₁₀ ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
PM _{2.5} ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
<i>Hazardous Air Pollutants</i>						
Benzene ^d	2.10E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Toluene ^d	3.40E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Hexane ^d	1.80	0.0058	0.0000	0.0000	0.0000	0.0058
Formaldehyde ^d	7.50E-02	0.0002	0.0000	0.0000	0.0000	0.0002
<i>Greenhouse Gases</i>						
CO ₂ ^f	120,162	386.9918	0.0000	0.0000	0.0000	386.9918
CH ₄ ^f	2.27	0.0073	0.0000	0.0000	0.0000	0.0073
N ₂ O ^f	0.23	0.0007	0.0000	0.0000	0.0000	0.0007

a AP-42 Table 1.4-1, Emission Factors for Natural Gas Combustion, 7/98

b Assumes produced gas contains no sulfur

c AP-42 Table 1.4-2, Emission Factors for Natural Gas Combustion, 7/98 (All Particulates are PM_{1.0})

d AP-42 Table 1.4-3, Emission Factors for Organic Compounds from Natural Gas Combustion, 7/98

e Assumes maximum development scenario

f Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.

Kleinfelder, Inc. Wellsite Emissions			Base Location: Williston Basin Well Type: Oil Well			
Production Phase						
Atmospheric Oil Tank Flashing Emissions						
Assumptions:						
Production Estimate:		150	barrels/day			
Production Days:		365	Days/Year			
Flasing Gas-to-Oil Ratio:		98	Scf/bbl	379.49 Scf/lb-mol		
Control Efficiency:		95	Percent (%)			
Flashing Gas Composition:						
Component	Mole %	Mole Weight (lb/lb-mol)	Emissions (Uncontrolled) Scf/Year	Emissions (Uncontrolled) lbs/Year	Emissions (Uncontrolled) Tons/Year	Emissions (Controlled) Tons/Year
Methane	17.8400	16.043	957205.2	40466.0018	20.2330	1.0117
Ethane	32.2588	30.07	1730845.914	137148.6380	68.5743	3.4287
Propane	30.9557	44.097	1660928.084	193000.9900	96.5005	4.8250
i-Butane	3.2347	58.123	173557.8285	26582.2595	13.2911	0.6646
n-Butane	10.4515	58.123	560775.2325	85888.7951	42.9444	2.1472
i-Pentane	1.3981	72.150	75015.0555	14262.1314	7.1311	0.3566
n-Pentane	1.7904	72.150	96063.912	18264.0155	9.1320	0.4566
Other Pentanes	0.0000	70.100	0	0.0000	0.0000	0.0000
Hexanes	0.2392	86.177	12834.276	2914.4889	1.4572	0.0729
Heptanes	0.3268	100.204	17534.454	4629.9571	2.3150	0.1157
Octanes	0.0810	114.231	4346.055	1308.2142	0.6541	0.0327
Nonanes	0.0103	128.258	552.6465	186.7805	0.0934	0.0047
Decanes +	0.0000	142.285	0	0.0000	0.0000	0.0000
Benzene	0.0204	78.120	1094.562	225.3213	0.1127	0.0056
Toluene	0.0163	92.130	874.5765	212.3237	0.1062	0.0053
Ethylbenzene	0.0017	106.160	91.2135	25.5164	0.0128	0.0006
2,2,4 Trimethylpentane	0.0030	78.120	160.965	33.1355	0.0166	0.0008
Xylenes	0.0062	106.160	332.661	93.0599	0.0465	0.0023
n-Hexane	0.1870	86.177	10033.485	2278.4675	1.1392	0.0570
Nitrogen	0.8693	28.013	46642.2915	3443.0170	1.7215	0.0861
Carbon Dioxide	0.3095	44.010	16606.2225	1925.8475	0.9629	0.0481
Hydrogen Sulfide	0.0000	34.080	0	0.0000	0.0000	0.0000
VOC Subtotal	48.72				174.95	8.75
HAPS Subtotal	0.23				1.43	0.07
Total	99.9999				266.4445	13.3222
Calculation:						
Scf/yr = (Mol% * scf/bbl * bbl/day * days/yr) / 100						
lb/yr = (scf/yr * mol wt.) / scf/lb-mol						
* Production and gas to oil ratio based on basin specific differences. Please see "Gas Stream Molar Ratios" tab and report for additional information.						

Kleinfelder, Inc. Wellsite Emissions	Base Location: Williston Basin Well Type: Oil Well																								
Production Phase																									
Wellsite Produced Water Tanks Venting																									
<p>Assumptions:</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 40%;">Average Estimated Water Production:</td> <td style="width: 20%; text-align: center;">36000</td> <td style="width: 40%;">Barrels Per Year</td> </tr> <tr> <td>Number of Water Tanks:</td> <td style="text-align: center;">1</td> <td>Tanks</td> </tr> <tr> <td>VOC Emissions Factor:</td> <td style="text-align: center;">0.2620</td> <td>lbs/bbl</td> </tr> <tr> <td>n-Hexane Emission Factor:</td> <td style="text-align: center;">0.0220</td> <td>lbs/bbl</td> </tr> <tr> <td>Benzene Emission Factor:</td> <td style="text-align: center;">0.0070</td> <td>lbs/bbl</td> </tr> </table> <p>Calculations:</p> <table border="1" style="margin-left: auto; margin-right: auto; border-collapse: collapse; text-align: center;"> <tr> <td style="width: 33%;">VOC Emissions:</td> <td style="width: 33%;">4.716</td> <td style="width: 33%;">Tons/Year</td> </tr> <tr> <td>Hexane Emissions:</td> <td>0.396</td> <td>Tons/Year</td> </tr> <tr> <td>Benzene Emissions:</td> <td>0.126</td> <td>Tons/Year</td> </tr> </table> <p style="margin-top: 20px;"> * Production conservatively based on estimated industry single well average * Emission factors based on only known lb/bbl factor, which was developed by the Colorado Department of Health and Environment (PS Memo 09-02). </p>		Average Estimated Water Production:	36000	Barrels Per Year	Number of Water Tanks:	1	Tanks	VOC Emissions Factor:	0.2620	lbs/bbl	n-Hexane Emission Factor:	0.0220	lbs/bbl	Benzene Emission Factor:	0.0070	lbs/bbl	VOC Emissions:	4.716	Tons/Year	Hexane Emissions:	0.396	Tons/Year	Benzene Emissions:	0.126	Tons/Year
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Production Phase
Truck Loading Emissions

AP - 42, Chapter 5.2

$$L_L = 12.46 \times S \times P \times M / T$$

L_L = Loading Loss Emission Factor (lbs VOC/1000 gal loaded)
S = Saturation Factor
P = True Vapor Pressure of the Loaded Liquid (psia)
M = Vapor Molecular Weight of the Loaded Liquid (lbs/lbmol)
T = Temperature of Loaded Liquid (°R)

$$\text{VOC Emissions (tpy)} = \frac{L_L (\text{lbs VOC}/1000 \text{ gal}) \times 42 \text{ gal/bbl} \times 365 \text{ days/year} \times \text{production (bbl/day)}}{1000 \text{ gal} \times 2000 \text{ lbs/ton}}$$

S ¹	P (psia) ²	M (lb/lbmol) ³	T (°F) ⁴	T (°R)	L _L (lb/1000 gal)	Production (bbl/day)	VOC (tpy)
0.6	1.80	50.00	40.00	499.67	1.35	150.0	1.55

Notes:

1. Saturation factor from AP-42, Table 5.2-1 (Submerged loading: dedicated normal service)
2. True vapor pressure is estimated from AP-42, Table 7.1-2 assuming an average daily temperature of either 40 or 50 deg F and an RVP of 10.0.
3. Molecular weight liquid vapor is estimated from AP-42, Table 7.1-2 assuming an RVP of 10.0.
4. Temperature based on the annual average temperature for basin location (either 40 or 50 degrees F based on options provided in AP-42 Table 7.1-2)

Kleinfelder, Inc. Wellsite Emissions	Base Location: Williston Basin Well Type: Oil Well																																																																																																											
Production Phase Pumpjack Unit Emissions																																																																																																												
<p>Assumptions:</p> <p style="text-align: center;">*Pumpjack engines only included at oil wells*</p> <table style="margin-left: auto; margin-right: auto;"> <tr> <td>Pumpjack Horsepower Rating:</td> <td>65.0</td> <td>Horsepower</td> </tr> <tr> <td>Load Factor:</td> <td>0.54</td> <td></td> </tr> <tr> <td>Brake Specific Fuel Consumption:</td> <td>7,750</td> <td>Btu/hp-hr</td> </tr> <tr> <td>Annual Operation:</td> <td>8,760</td> <td>Hours/Year</td> </tr> </table> <p>Equations:</p> <p style="text-align: center;"> Emissions (lbs/hr) = Emission Factor (g/hp-hr) * Power (hp) 453.6 g/lb </p> <table border="1" style="width: 100%; border-collapse: collapse; margin-top: 20px;"> <thead> <tr> <th style="text-align: center;">Pollutant</th> <th style="text-align: center;">Emission Factor ^a (lb/MMBtu)</th> <th style="text-align: center;">Emission Factor ^a (g/hp-hr)</th> <th style="text-align: center;">Emissions (lb/hr)</th> <th style="text-align: center;">Emissions (Tons/Year)</th> </tr> </thead> <tbody> <tr><td colspan="5"><i>Criteria Pollutants & VOC</i></td></tr> <tr><td>NOx</td><td></td><td style="text-align: center;">2.80</td><td style="text-align: center;">0.22</td><td style="text-align: center;">0.9490</td></tr> <tr><td>CO</td><td></td><td style="text-align: center;">4.80</td><td style="text-align: center;">0.37</td><td style="text-align: center;">1.6269</td></tr> <tr><td>VOC</td><td style="text-align: center;">0.12</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0326</td><td style="text-align: center;">0.1430</td></tr> <tr><td>PM₁₀ ^b</td><td style="text-align: center;">4.83E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">1.31E-02</td><td style="text-align: center;">5.76E-02</td></tr> <tr><td>PM_{2.5} ^b</td><td style="text-align: center;">4.83E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">1.31E-02</td><td style="text-align: center;">5.76E-02</td></tr> <tr><td>SO₂</td><td style="text-align: center;">5.88E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0002</td><td style="text-align: center;">0.0007</td></tr> <tr><td colspan="5"><i>Hazardous Air Pollutants</i></td></tr> <tr><td>Benzene</td><td style="text-align: center;">1.94E-03</td><td style="text-align: center;">-</td><td style="text-align: center;">5.28E-04</td><td style="text-align: center;">2.31E-03</td></tr> <tr><td>Toluene</td><td style="text-align: center;">9.63E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">2.62E-04</td><td style="text-align: center;">1.15E-03</td></tr> <tr><td>Ethylbenzene</td><td style="text-align: center;">1.08E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">2.94E-05</td><td style="text-align: center;">1.29E-04</td></tr> <tr><td>Xylenes</td><td style="text-align: center;">2.68E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">7.29E-05</td><td style="text-align: center;">3.19E-04</td></tr> <tr><td>Formaldehyde</td><td style="text-align: center;">5.52E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0150</td><td style="text-align: center;">0.0658</td></tr> <tr><td>n-Hexane</td><td style="text-align: center;">4.45E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">1.21E-04</td><td style="text-align: center;">5.30E-04</td></tr> <tr><td colspan="5"><i>Greenhouse Gases</i></td></tr> <tr><td>CO₂ ^c</td><td style="text-align: center;">117</td><td style="text-align: center;">-</td><td style="text-align: center;">31.80</td><td style="text-align: center;">139</td></tr> <tr><td>CH₄</td><td style="text-align: center;">0.002</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0006</td><td style="text-align: center;">0.0026</td></tr> <tr><td>N₂O</td><td style="text-align: center;">0.0002</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0001</td><td style="text-align: center;">0.0003</td></tr> </tbody> </table> <p style="margin-top: 20px;"> a AP-42 Table 3.2-3 Uncontrolled Emission Factors for 4-Stroke Rich-Burn Engines, 7/00; and Subpart JJJJ for NOX and CO emission rates. b PM = sum of PM filterable and PM condensable c Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu. </p> <p style="margin-top: 10px;"> - Network website for the 1999 National-Scale Air Toxics Assessment at http://www.epa.gov/ttn/atw/nata1999/nsata99.html </p>		Pumpjack Horsepower Rating:	65.0	Horsepower	Load Factor:	0.54		Brake Specific Fuel Consumption:	7,750	Btu/hp-hr	Annual Operation:	8,760	Hours/Year	Pollutant	Emission Factor ^a (lb/MMBtu)	Emission Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	<i>Criteria Pollutants & VOC</i>					NOx		2.80	0.22	0.9490	CO		4.80	0.37	1.6269	VOC	0.12	-	0.0326	0.1430	PM₁₀ ^b	4.83E-02	-	1.31E-02	5.76E-02	PM_{2.5} ^b	4.83E-02	-	1.31E-02	5.76E-02	SO₂	5.88E-04	-	0.0002	0.0007	<i>Hazardous Air Pollutants</i>					Benzene	1.94E-03	-	5.28E-04	2.31E-03	Toluene	9.63E-04	-	2.62E-04	1.15E-03	Ethylbenzene	1.08E-04	-	2.94E-05	1.29E-04	Xylenes	2.68E-04	-	7.29E-05	3.19E-04	Formaldehyde	5.52E-02	-	0.0150	0.0658	n-Hexane	4.45E-04	-	1.21E-04	5.30E-04	<i>Greenhouse Gases</i>					CO₂ ^c	117	-	31.80	139	CH₄	0.002	-	0.0006	0.0026	N₂O	0.0002	-	0.0001	0.0003
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Kleinfelder, Inc. Wellsite Emissions	Base Location: Williston Basin Well Type: Oil Well																								
Production Phase																									
Wellsite Dehydrator Emissions																									
<p>Assumptions:</p> <p>Number of Dehy Units: 0 Units</p> <p>Calculations:</p> <p>Calculations and specifications derived from Pinedale Anticline Final SEIS GRI-GLYCalc 4.0 operated with: 4 MMSCFD, 0.32 gpm glycol flow, average representative gas analysis, and 95% control efficiency</p> <p>Emissions:</p> <table border="1" data-bbox="553 987 1062 1478"> <thead> <tr> <th>Species</th><th>Total Project Emissions (tons/year)</th></tr> </thead> <tbody> <tr> <td>Total VOC</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Hazardous Air Pollutants</i></td></tr> <tr> <td>Benzene</td><td>0.000</td></tr> <tr> <td>Toluene</td><td>0.000</td></tr> <tr> <td>Ethylbenzene</td><td>0.000</td></tr> <tr> <td>Xylenes</td><td>0.000</td></tr> <tr> <td>n-Hexane</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Greenhouse Gases</i></td></tr> <tr> <td>CO₂</td><td>0.000</td></tr> <tr> <td>CH₄^a</td><td>0.000</td></tr> <tr> <td>N₂O</td><td>0.000</td></tr> </tbody> </table> <p>Note, no greenhouse gas emissions included for dehydrator in Pinedale EIS</p>		Species	Total Project Emissions (tons/year)	Total VOC	0.000	<i>Hazardous Air Pollutants</i>		Benzene	0.000	Toluene	0.000	Ethylbenzene	0.000	Xylenes	0.000	n-Hexane	0.000	<i>Greenhouse Gases</i>		CO₂	0.000	CH₄^a	0.000	N₂O	0.000
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: Williston Basin
Well Type: Oil Well

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks: 50 Trips/Location
 Light Duty Haul Trucks 0 Trips/Location Total Trips: 50 Trips

Heavy Duty Haul Trucks 2 Trips/Location
 Water Trucks 40 Trips/Location Total Trips: 42 Trips

* Miles and number of trips based on research and industry knowledge;
 please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (g/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NO_x	7.44E-02	6.25E-02	7.39E-03	7.39E-03	6.99E-02
CO	1.98E-02	1.66E-02	7.26E-02	7.26E-02	8.92E-02
VOC	3.16E-03	2.65E-03	3.54E-03	3.54E-03	6.19E-03
SO₂	4.57E-05	3.84E-05	2.83E-05	2.83E-05	6.67E-05
PM₁₀	4.22E-03	3.54E-03	1.94E-04	1.94E-04	3.74E-03
PM_{2.5}	4.09E-03	3.44E-03	1.79E-04	1.79E-04	3.61E-03
CO₂	1.88E+00	1.58E+00	1.13E+00	1.13E+00	2.70E+00
CH₄	7.61E-05	6.39E-05	4.56E-05	4.56E-05	1.10E-04
N₂O	1.52E-05	1.28E-05	9.13E-06	9.13E-06	2.19E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

c Assumes maximum development scenario

Kleinfelder, Inc. Wellsite Emissions			Base Location: Williston Basin Well Type: Oil Well				
Production Phase							
Pneumatic Device Emissions							
Wellsite Pneumatic Inventory:							
Devices:		Classification	Quantity	Emission Factor (Scf/hr/unit)			
			0	0.00			
			0	0.00			
			0	0.00			
Pumps:				0.00			
Annual Equipment Run Time:		8760	Hours/Year	379.49 Scf/lb-mol			
Pneumatic Device Control: ^b		0	Percent				
* Low bleed and intermittent bleed emission factors (scf/hr) based on Subpart W, Table W-1A							
* Quantity of devices based on typical industry values							
Component	Mole %	Mole Weight lb/lb-mol	(None) Tons/Year	(None) Tons/Year	(None) Tons/Year	Pneumatic Pumps Tons/Year	Total Tons/Year
Methane	88.9720	16.0	0.000	0.000	0.000	0.000	0.000
Ethane	5.7920	30.1	0.000	0.000	0.000	0.000	0.000
Propane	1.3650	44.1	0.000	0.000	0.000	0.000	0.000
i-Butane	0.3700	58.1	0.000	0.000	0.000	0.000	0.000
n-Butane	0.2610	58.1	0.000	0.000	0.000	0.000	0.000
i-Pentane	0.1550	72.2	0.000	0.000	0.000	0.000	0.000
n-Pentane	0.1020	72.2	0.000	0.000	0.000	0.000	0.000
Other Pentanes	0.0000	70.1	0.000	0.000	0.000	0.000	0.000
Hexanes	0.1460	86.2	0.000	0.000	0.000	0.000	0.000
Heptanes	0.0930	100.2	0.000	0.000	0.000	0.000	0.000
Octanes	0.0440	114.2	0.000	0.000	0.000	0.000	0.000
Nonanes	0.0160	128.3	0.000	0.000	0.000	0.000	0.000
Decanes +	0.0050	142.3	0.000	0.000	0.000	0.000	0.000
Benzene	0.0270	78.1	0.000	0.000	0.000	0.000	0.000
Toluene	0.0190	92.1	0.000	0.000	0.000	0.000	0.000
Ethylbenzene	0.0000	106.2	0.000	0.000	0.000	0.000	0.000
2,2,4 Trimethylpentane	0.0000	78.1	0.000	0.000	0.000	0.000	0.000
Xylenes	0.0110	106.2	0.000	0.000	0.000	0.000	0.000
n-Hexane	0.1460	86.2	0.000	0.000	0.000	0.000	0.000
Nitrogen	0.0940	28.0	0.000	0.000	0.000	0.000	0.000
Carbon Dioxide	2.5280	44.0	0.000	0.000	0.000	0.000	0.000
Hydrogen Sulfide	0.0000	34.1	0.000	0.000	0.000	0.000	0.000
VOC Subtotal	2.8	1492.8	0.00	0.00	0.00	0.00	0.00
HAPS Subtotal	0.2	546.9	0.00	0.00	0.00	0.00	0.00
Total	100.1	1645.0	0.00	0.00	0.00	0.00	0.00
^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.							
^b 98% control input is a result of the Wyoming Department of Environment Quality requirement, and only pertains to the Upper Green River Basin.							

APPENDIX F

EMISSION INVENTORY FOR THE DENVER BASIN OIL WELL

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Location Selection:

Geography: **Well Type:**
 Denver Basin Oil Well

- Choose geography/basin, and well type will automatically fill
- < Choose Uinta/Piceance Basin for deep gas wells with little condensate
- < Choose Upper Green River Basin for deep gas wells with dehydrators and higher condensate
- < Choose San Juan Basin for shallow gas wells with little to no condensate
- < Choose Williston Basin for deep oil wells with high gas
- < Choose Denver Basin for shallow oil wells with low gas

If the user wants to change any specifications, do so within the "Constants and References" tab, as all other tabs connect to it.

Pollutant:	Total Emissions (Tons per Year)								
	NO _x	CO	VOC	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O
Construction Phase:	0.47	0.29	0.04	0.0001	1.96	0.06	33.84	0.001	0.0003
Development Phase:	4.45	1.16	0.31	0.0002	4.48	0.16	623.66	1.06	0.0394
Operation Phase:	1.34	1.99	6.39	0.0008	0.10	0.28	391.46	0.72	0.0010
Total:	6.26	3.43	6.74	0.0010	6.55	0.50	1048.97	1.78	0.0407

Pollutant:	Total Emissions (Tons per Year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	HAPs
Construction Phase:	0.00	0.00	0.00	0.00	0.00	0.00
Development Phase:	1.35	0.95	0.0000	0.55	7.31	10.17
Operation Phase:	0.06	0.01	0.00062	0.004	0.24	0.38
Total:	1.41	0.96	0.00062	0.56	7.54	10.54

CO ₂ equivalent (Global Warming Potential)	
Total TPY:	1098.95
CO ₂ equivalent conversions:	
CO ₂	1.00
CH ₄	21.00
N ₂ O	310.00

H ₂ S Emissions	
Total TPY:	0.00

* If H₂S in gas, input value in "Gas Stream Molar Ratios" tab, and potential emissions will calculate here. Current assumption is no H₂S in gas stream.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Road Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	4	Days/Location	(Typical Value)
	48.0	Dozer Hours/Location	(Typical Value)
	48.0	Backhoe Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅ (AP-42 Table 11.9-1, 7/98)		
PM _{2.5} Multiplier:	0.105 * TSP (AP-42 Table 11.9-1, 7/98)		

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98 & 7/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0473	1.97	0.0473	0.0946
PM₁₅	0.50	0.0120	0.50	0.0120	0.0241
PM₁₀	0.38	0.0090	0.38	0.0090	0.0181
PM_{2.5}	0.21	0.0050	0.05	0.0013	0.0062

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase
Road Grader Particulate Matter

Assumptions:

Grading Length:	6.00	miles	(Typical Value)
Construction Schedule:	3	Days/Location	(Typical Value)
	12	Hours/Day	(Typical Value)
	36	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	
Average Grader Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 16.12 lbs TSP/Location

Emissions = 7.71 lbs PM₁₅/Location

Grader Construction Emissions			
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	16.12	0.45	8.06E-03
PM₁₅	7.71	0.21	3.86E-03
PM₁₀	4.63	0.13	2.31E-03
PM_{2.5}	0.50	0.01	2.50E-04

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Well Pad Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location (Dozer)	(Typical Value)
	70	Hours/Location (Back Hoe)	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs/hr)} = 5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs/hr)} = 1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

^a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase
Well Pad Grader Particulate Matter

Assumptions:

Construction Schedule:	4.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	40	Hours/Location	(Typical Value)
Watering Control Efficiency	50	Percent (%)	(Typical Value)
Average Grader Speed	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
Distance Graded	2.84	Miles/Location	(Typical Value)
PM ₁₀ Multiplier	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
 Bulldozing Overburden Emissions, Western Surface Coal Mining, 10/98

$$\text{Emissions (TSP lbs)} = 0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$$

$$\text{Emissions (PM}_{15} \text{ lbs)} = 0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$$

Emissions = 7.63 lbs TSP/well pad

Emissions = 3.65 lbs PM₁₅/well pad

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	7.63	0.19	0.0038
PM₁₅	3.65	0.09	0.0018
PM₁₀	2.19	0.05	0.0011
PM_{2.5}	0.24	0.01	0.0001

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Pipeline Dozer and Backhoe Particulate Matter

Assumptions:

Construction Schedule:	7.0	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Soil Moisture Content:	7.9	Percent (%)	AP-42 Table 11.9-3, 7/98
Soil Silt Content:	6.9	Percent (%)	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.75 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.105 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs/hr) = $5.7 * (\text{soil silt content } \%)^{1.2} * (\text{soil moisture content } \%)^{-1.3} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs/hr) = $1.0 * (\text{soil silt content } \%)^{1.5} * (\text{soil moisture content } \%)^{-1.4} * \text{Control Efficiency}$

Emissions = 1.97 lbs TSP/hour/piece of equipment

Emissions = 0.50 lbs PM₁₅/hour/piece of equipment

	Dozer Emissions ^a		Backhoe Emissions ^a		Total
	lbs/hr	Tons/Location	lbs/hr	Tons/Location	Tons/Location
TSP	1.97	0.0690	1.97	0.0690	0.14
PM₁₅	0.50	0.0176	0.50	0.0176	0.04
PM₁₀	0.38	0.0132	0.38	0.0132	0.03
PM_{2.5}	0.21	0.0072	0.21	0.0072	0.01

a Assumes one dozer and one backhoe. Backhoe emissions factors are conservatively estimated as equivalent to Dozer emissions.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Pipeline Grader Particulate Matter

Assumptions:

Distance Graded:	12.50	Miles/Location	(Typical Value)
Construction Schedule:	7	Days/Location	(Typical Value)
	10	Hours/Day	(Typical Value)
	70	Hours/Location	(Typical Value)
Watering Control Efficiency:	50	Percent (%)	(Typical Value)
Mean Vehicle Speed:	7.1	Miles/Hour	AP-42 Table 11.9-3, 7/98
PM ₁₀ Multiplier:	0.6 * PM ₁₅	(AP-42 Table 11.9-1, 7/98)	
PM _{2.5} Multiplier:	0.031 * TSP	(AP-42 Table 11.9-1, 7/98)	

Equations: From AP-42 tables 11.9-1 and 11.9-3 for
Bulldozing Overburden Emissions, Western Surface Coal Mining, 7/98

Emissions (TSP lbs) = $0.040 * (\text{Mean Vehicle Speed})^{2.5} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions (PM₁₅ lbs) = $0.051 * (\text{Mean Vehicle Speed})^{2.0} * \text{Distance Graded} * \text{Control Efficiency}$

Emissions = 33.58 lbs TSP/well

Emissions = 16.07 lbs PM₁₅/well

	Grader Construction Emissions		
	lbs/Location	lbs/hr/Location	Tons/Location
TSP	33.58	0.48	0.0168
PM₁₅	16.07	0.23	0.0080
PM₁₀	9.64	0.14	0.0048
PM_{2.5}	1.04	0.01	0.0005

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Heavy Diesel Truck Trips:

Road Construction:	7	Trips			
Well Pad Construction:	8	Trips	Total Trips:	21	Trips
Pipeline Construction:	6	Trips			

Light Duty Pickup Truck Trips:

Road Construction:	16	Trips			
Well Pad Construction:	28	Trips	Total Trips:	100	Trips
Pipeline Construction:	56	Trips			

* All assumptions above are based on typical industry values

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NOx	7.44E-02	3.12E-02	7.39E-03	1.48E-02	4.60E-02
CO	1.98E-02	8.32E-03	7.26E-02	1.45E-01	1.54E-01
VOC	3.16E-03	1.33E-03	3.54E-03	7.08E-03	8.41E-03
SO2	4.57E-05	1.92E-05	2.83E-05	5.66E-05	7.58E-05
PM10	4.22E-03	1.77E-03	1.94E-04	3.88E-04	2.16E-03
PM2.5	4.09E-03	1.72E-03	1.79E-04	3.58E-04	2.08E-03
CO2	1.88	0.79	1.13	2.25	3.04
CH4	7.61E-05	3.19E-05	4.56E-05	9.13E-05	1.23E-04
N2O	1.52E-05	6.39E-06	9.13E-06	1.83E-05	2.46E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Construction Heavy Equipment Tailpipe Emissions

Assumptions:

Fuel and Engine:

Brake Specific Fuel Consumption, Avg. (BSFC) 8250 btu/hp-hr (Typical Value)
 Diesel Higher Heating Value (HHV) 0.138 mmBtu/Gallon (Typical Value)

Trackhoe:

Working Hours 188 Total Hours (Typical Value)
 Rated Horsepower 100 (Estimate)
 Load Factor 0.59 (Default LF from NONROAD model for Tractors/Loaders/Backhoes)

Dozer:

Working Hours 188 Total Hours (Typical Value)
 Rated Horsepower 140 (Estimate)
 Load Factor 0.59 (Default LF from NONROAD model for Crawler Tractor/Dozers)

Grader:

Working Hours 130 Total Hours (Typical Value)
 Rated Horsepower 250 (Estimate)
 Load Factor 0.59 (Default LF from NONROAD model for Graders)

Total Horsepower Hours: 45795.8 Hp-hrs (Sum of all horsepower above)
Total Fuel Usage: 2737.79 Gallons Diesel Fuel

Equations:

Total Fuel Usage: (btu-hp-hr * hp-hrs) / Mmbtu-gal) / 1,000,000
 Emissions (tons/year/pad) = $\frac{\text{Emission Factor (g/mile)} * \text{Trip Distance (miles)} * \text{Load Factor}}{453.6 \text{ (g/lb)} * 2000 \text{ (lb/tons)}}$

Heavy Const. Vehicles	Backhoe			Dozer			Grader		
	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	E. Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)
NOx	8.38	1.09E+00	1.02E-01	8.38	1.53E+00	1.43E-01	8.38	2.72E+00	1.77E-01
CO	2.7	3.51E-01	3.30E-02	2.7	4.92E-01	4.62E-02	2.7	8.78E-01	5.71E-02
VOC ^b	0.68	8.84E-02	8.31E-03	0.68	1.24E-01	1.16E-02	0.68	2.21E-01	1.44E-02
PM₁₀	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03
PM_{2.5}	0.39	5.07E-02	4.77E-03	0.39	7.10E-02	6.68E-03	0.39	1.27E-01	8.24E-03

Heavy Const. Vehicles	Total Emissions ^c (tons/yr)
NOx	0.42
CO	0.14
VOC	0.03
PM₁₀	0.02
PM_{2.5}	0.02

Greenhouse Gas Emissions:

	Diesel EF kg/mmbtu	Emissions lbs	Emissions Tons
CO ₂	73.96	61604.19	30.80
CH ₄	0.003	2.50	0.0012
N ₂ O	0.0006	0.50	0.0002

a From Table A-4 of Exhaust and Crankcase Emission Factors for NONROAD Engine Modeling - Compression Ignition, EPA-420-R-10-018, July 2010.

b Emission Factor represents total Hydrocarbon Emissions

c Converted from emission factor for Distillate Fuel Oil #2 (diesel) as listed in Table C-1 to Subpart C of Part 98 - Default Emission Factors and High Heat Values for Various Types of Fuel.

Listed Factor:

73.96 kg CO₂/mmBtu
 393 hp-hr = mmBtu
 188.2 g CO₂/hp-hr

Kleinfelder, Inc. Wellsite Emissions		Base Location: Denver Basin Well Type: Oil Well													
Construction Phase															
Wind Erosion Fugitive Dust															
Assumptions:															
Threshold Friction Velocity (U _t)	1.02 1.33	m/s (2.28 mph) for well pads (AP-42 Table 13.2.5-2 Overburden - Western Surface Coal Mine) m/s (2.97 mph) for roads (AP-42 Table 13.2.5-2 Roadbed material)													
Initial Disturbance Area															
Total Access Road/ROW Area Per Location:	976,800	Square Meters	(Typical Value)												
Total Well Pad Area Disturbed Per Location:	50,000	Square Meters	(Typical Value)												
Total Area Disturbed Per Location:	1,026,800	Square Meters	(Typical Value)												
Exposed Surface Type	Flat														
Meteorological Data	2002 Grand Junction (obtained from NCDC website)														
Fastest Mile Wind Speed:	45	miles/hour	(Typical Value)												
Fastest Mile Wind Speed (U ₁₀ ⁺)	20.12	meters/sec (45 mph) reported as fastest 2-minute wind speed for Grand Junction (2002)													
Number soil of disturbances	1.00	for well pads (Assumption, disturbance at construction and reclamation) constant for dirt roads													
Equations (AP-42 13.2.5.2 Industrial Wind Erosion)															
Friction Velocity U* = 0.053 U ₁₀ ⁺															
Erosion Potential P (g/m ² /period) = 58*(U*-U _t *) ² + 25*(U*-U _t *) for U*>U _t *, P = 0 for U*< U _t *															
Emissions (tons/year) = Erosion Potential(g/m ² /period)*Disturbed Area(m ²)*Disturbances/year*(k)/(453.6 g/lb)/2000 lbs/ton/Develop Period															
<table><tr><th colspan="3">Particle Size Multiplier (k)</th></tr><tr><td>30 μm</td><td><10 μm</td><td><2.5 μm</td></tr><tr><td>1.0</td><td>0.5</td><td>0.075</td></tr></table>				Particle Size Multiplier (k)			30 μm	<10 μm	<2.5 μm	1.0	0.5	0.075			
Particle Size Multiplier (k)															
30 μm	<10 μm	<2.5 μm													
1.0	0.5	0.075													
<table><tr><th>Maxium U₁₀⁺ Wind Speed (m/s)</th><th>Maximum U* Friction Velocity m/s</th><th>Well U_t* Threshold Velocity^a m/s</th><th>Well Pad Erosion Potential g/m²</th><th>Road U_t* Threshold Velocity^a m/s</th><th>Road Erosion Potential g/m²</th></tr><tr><td>20.12</td><td>1.07</td><td>1.02</td><td>1.28</td><td>1.33</td><td>0.00</td></tr></table>				Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²	20.12	1.07	1.02	1.28	1.33	0.00
Maxium U ₁₀ ⁺ Wind Speed (m/s)	Maximum U* Friction Velocity m/s	Well U _t * Threshold Velocity ^a m/s	Well Pad Erosion Potential g/m ²	Road U _t * Threshold Velocity ^a m/s	Road Erosion Potential g/m ²										
20.12	1.07	1.02	1.28	1.33	0.00										
Wind Erosion Emissions															
<table><tr><th>Particulate Species</th><th>Well Pad (tons/year)</th><th>Roads/Pipelines (tons/year)</th></tr><tr><td>TSP</td><td>7.05E-02</td><td>0.00E+00</td></tr><tr><td>PM₁₀</td><td>3.52E-02</td><td>0.00E+00</td></tr><tr><td>PM_{2.5}</td><td>5.28E-03</td><td>0.00E+00</td></tr></table>				Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)	TSP	7.05E-02	0.00E+00	PM ₁₀	3.52E-02	0.00E+00	PM _{2.5}	5.28E-03	0.00E+00
Particulate Species	Well Pad (tons/year)	Roads/Pipelines (tons/year)													
TSP	7.05E-02	0.00E+00													
PM ₁₀	3.52E-02	0.00E+00													
PM _{2.5}	5.28E-03	0.00E+00													

Kleinfelder, Inc.				Base Location: Denver Basin					
Website Emissions				Well Type: Oil Well					
Construction, Development, and Production Phase									
Construction, Development, and Operations Traffic Fugitive Dust Emissions									
Assumptions:									
				Round Trip Miles	40				
				Round Trip (Paved) Miles	16				
				Round Trip (Un-Paved) Miles	24				
				Precipitation Days (P)	50				
Unpaved Calculation AP-42, Chapter 13.2.2 November 2006				$E (PM_{10}) / VMT = 1.5 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$ $E (PM_{2.5}) / VMT = 0.15 * (S/12)^{0.9} * (W/3)^{0.45} * (365-p)/365$					
Silt Content (S)				8.5		AP 42 13.2.2-1 Mean Silt Content Construction Sites			
Paved Calculation AP-42, Chapter 13.2.1 January 2011				$E (PM_{10}) / VMT = 0.0022 * (sL)^{0.91} * (W)^{0.42} * (1-(P/(365*4)))$ $E (PM_{2.5}) / VMT = 0.00054 * (sL)^{0.91} * (W)^{0.42} * (1-(P/(365*4)))$					
Silt Loading (sL)				0.6		AP-42 Table 13.2.1-2 baseline low volume roads			
Unpaved Calculations:									
Construction Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	3.04	1534.5	0.8	0.3	153.5	0.1
	Light Duty Pickup Trucks	5,000	100	0.87	2098.5	1.0	0.1	209.8	0.1
	Total:				3633.00	1.82		363.30	0.18
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Heavy Duty Haul Trucks	80,000	21	0.0574	19.3	0.0096	0.014	4.7	0.0024
	Light Duty Pickup Trucks	5,000	100	0.0034	5.4	0.0027	0.001	1.3	0.0007
	Total:				24.7	0.0		6.1	0.0
Unpaved Calculations:									
Development Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	84	0.87	1762.7	0.9	0.1	176.3	0.1
	Light Duty Haul Trucks	7,500	11	1.05	277.0	0.1	0.1	27.7	0.0
	Heavy Duty Haul Trucks	80,000	67	3.04	4895.9	2.4	0.3	489.6	0.2
	Water Trucks	70,000	24	2.87	1651.5	0.8	0.3	165.1	0.1
	Total:				8587.11	4.29		858.71	0.43
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips						
	Light Duty Pickup Trucks	5000	84	0.00	4.6	0.0	0.0	1.1	0.0006
	Light Duty Haul Trucks	7500	11	0.01	0.9	0.0	0.0	0.2	0.0001
	Heavy Duty Haul Trucks	80000	67	0.06	61.5	0.0	0.0	15.1	0.0076
	Water Trucks	70,000	24	0.05	19.2	0.0	0.0	4.7	0.0024
	Total:				86.3	0.0		21.2	0.0
Unpaved Calculations:									
Production Phase	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	50	0.87	1049.23	0.52	0.0874	104.92	0.0525
	Light Duty Haul Trucks	7,500	0	1.05	0.00	0.00	0.1049	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	3.04	146.15	0.07	0.3045	14.61	0.0073
	Water Trucks	70,000	40	2.87	2752.45	1.38	0.2867	275.25	0.1376
	Total:				3947.83	1.97		394.78	0.20
Paved Calculations:									
	Vehicle Type	Average Weight (lbs)	Vehicle Round Trips	PM ₁₀ (lb/VMT)	PM ₁₀ (lbs)	PM ₁₀ (Tons)	PM _{2.5} (lb/VMT)	PM _{2.5} (lbs)	PM _{2.5} (Tons)
	Light Duty Pickup Trucks	5,000	50	0.00	2.72	0.0014	0.0008	0.67	0.0003
	Light Duty Haul Trucks	7,500	0	0.01	0.00	0.0000	0.0013	0.00	0.0000
	Heavy Duty Haul Trucks	80,000	2	0.06	1.84	0.0009	0.0141	0.45	0.0002
	Water Trucks	70,000	40	0.05	32.07	0.0160	0.0123	7.87	0.0039
	Total:				36.62	0.02		8.99	0.00
Annual Total				Unpaved Roads PM ₁₀ (tons) 8.08			Unpaved Roads PM _{2.5} (tons) 0.8		
				Paved Roads PM ₁₀ 0.1			Paved Roads PM _{2.5} 0.0		
				Total:			8.2		
							0.8		

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Development Phase
Drill Rig Emissions

Assumptions:

Parameter	Value
Days of Operation	12 (Typical Value)
Hours of Operation	288 (Typical Value)
Diesel Fuel Sulfur Content	0.000015 (Typical Value)

Parameter	Value	Units
BSFC (Avg.)	8250 (Typical Value)	btu/hp-hr
Diesel HHV	0.138 (Typical Value)	mmbtu/gal

Engine	HP *	Load Factor	Run time (hrs)	Total Hp-hrs
Vertical Drill Rig Engine	550	0.42	96	22176
Horizontal Drill Rig Engine	2,950	0.59	192	334176
Drill Rig Generator	350	0.42	288	42336
Trailers Generator	150	0.42	288	18144
Air Compressor	550	0.42	96	22176
Air Compressor	550	0.42	96	22176
Air Compressor Booster	650	0.42	96	26208
Forklift	120	0.42	96	4838.4
Aerial Lift	50	0.42	12	252
Frontend loader	150	0.42	12	756
Dozer	175	0.42	6	441
-	0	0.00	0	0
-	0	0.00	0	0
-	0	0.00	0	0
-	0	0.00	0	0
Total HP	6,245			

Total: 493,679 Hp-hrs

Fuel Usage: 29,513 Gallons of Diesel Total Fuel Usage: (btu/hp-hr * hp-hrs) * gal/btu

Greenhouse Gasses:

	Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location
CO2	73.96	664094.07	332.05
CH4	0.003	26.94	0.01
N2O	0.0006	5.39	0.00

Greenhouse gas emission factors from Subpart C, Table C-1 and C-2

Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)
Vertical Drill Rig Engine	22176	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Horizontal Drill Rig Engine	334176	0.7642	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Drill Rig Generator	42336	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Trailers Generator	18144	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Air Compressor	22176	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor	22176	0.8425	4.3351	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Air Compressor Booster	26208	1.3272	4.1000	0.1316	0.1277	1.27E-05	0.1636	7.76E-04	2.81E-04	1.93E-04
Forklift	4838.4	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Aerial Lift	252	3.4900	8.3800	0.7220	0.7003	1.27E-05	0.9900	7.76E-04	2.81E-04	1.93E-04
Frontend loader	756	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
Dozer	441	2.7000	8.3800	0.4020	0.3899	1.27E-05	0.6800	7.76E-04	2.81E-04	1.93E-04
-	0	0.0000	0.0000	0.0000	0.0000	1.27E-05	0.0000	0.00E+00	0.00E+00	0.00E+00
-	0	0.0000	0.0000	0.0000	0.0000	1.27E-05	0.0000	0.00E+00	0.00E+00	0.00E+00
-	0	0.0000	0.0000	0.0000	0.0000	1.27E-05	0.0000	0.00E+00	0.00E+00	0.00E+00

Engine	CO (Tons/yr)	NO _x (Tons/yr)	PM ₁₀ (Tons/yr)	PM _{2.5} (Tons/yr)	SO ₂ (Tons/yr)	VOC (Tons/yr)	Benzene (Tons/yr)	Toulene (Tons/yr)	Xylenes (Tons/yr)
Vertical Drill Rig Engine	0.02059	0.10597	0.00322	0.00312	3.10E-07	0.00400	0.00007	0.00003	0.00002
Horizontal Drill Rig Engine	0.28150	1.51030	0.04848	0.04702	4.68E-06	0.06026	0.00107	0.00039	0.00027
Drill Rig Generator	0.12600	0.39107	0.01876	0.01820	5.93E-07	0.03173	0.00014	0.00005	0.00003
Trailers Generator	0.05400	0.16760	0.00804	0.00780	2.54E-07	0.01360	0.00006	0.00002	0.00001
Air Compressor	0.02059	0.10597	0.00322	0.00312	3.10E-07	0.00400	0.00007	0.00003	0.00002
Air Compressor	0.02059	0.10597	0.00322	0.00312	3.10E-07	0.00400	0.00007	0.00003	0.00002
Air Compressor Booster	0.03834	0.11845	0.00380	0.00369	3.67E-07	0.00473	0.00008	0.00003	0.00002
Forklift	0.01440	0.04469	0.00214	0.00208	6.77E-08	0.00363	0.00002	0.00001	0.00000
Aerial Lift	0.00097	0.00233	0.00020	0.00019	3.53E-09	0.00028	0.00000	0.00000	0.00000
Frontend loader	0.00225	0.00698	0.00034	0.00032	1.06E-08	0.00057	0.00000	0.00000	0.00000
Dozer	0.00131	0.00407	0.00020	0.00019	6.17E-09	0.00033	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
-	0.00000	0.00000	0.00000	0.00000	0.00E+00	0.00000	0.00000	0.00000	0.00000
Total:	0.58057	2.56341	0.09160	0.08886	0.00001	0.12712	0.00158	0.00057	0.00039

Emission Factors

- Drill rig emission factors based on Tier II engines
- All other engine emission factors based on Tier 0 engines (typical values)
- HAP emission factors from AP-42 Volume I, Large Stationary Diesel Engines Table 3.4-3

Calculations:

ton/year: (Total hp-hr * g/hp-hr) * lb-gram / lb-ton

*** Drill rig horsepower developed based on:**

- 1 Williston Basin: 2,100 from Jonah, Wyoming RMP
- 2 San Juan Basin: 2,100 from River Valley RMP
- 3 Upper Green River Basin: 2,100 from Jonah, Wyoming RMP
- 4 Denver Basin: 2,950 from River Valley RMP
- 5 Uintah Basin: 2,952 from River Valley RMP

Note, runtime for each drilling event is based on research and industry experience dependent upon each basi

Kleinfelder, Inc. Wellsite Emissions					Base Location: Denver Basin Well Type: Oil Well																																																																																																							
Development Phase																																																																																																												
Conductor Pipe Set Emissions																																																																																																												
Assumptions:																																																																																																												
<table><tr><th>Parameter</th><th>Value</th></tr><tr><td>Days of Operation</td><td>2</td></tr><tr><td>Hours of Operation</td><td>24</td></tr><tr><td>Diesel Fuel Sulfur Content</td><td>0.000015</td></tr></table>		Parameter	Value	Days of Operation	2	Hours of Operation	24	Diesel Fuel Sulfur Content	0.000015	<table><tr><th>Parameter</th><th>Value</th><th>Units</th></tr><tr><td>BSFC (Avg.)</td><td>8250</td><td>btu/hp-hr</td></tr><tr><td>Diesel HHV</td><td>0.138</td><td>mmbtu/gal</td></tr></table> <div>(Typical Value)</div> <div>(Typical Value)</div>								Parameter	Value	Units	BSFC (Avg.)	8250	btu/hp-hr	Diesel HHV	0.138	mmbtu/gal																																																																																		
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Workovers:					Greenhouse Gases:																																																																																																							
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Total Horsepower: 400					Greenhouse gas emission factors from Subpart C, Table C-1 and C-2																																																																																																							
Total: 4,032 Hp-hrs																																																																																																												
Fuel Usage: 241 Gallons of Diesel					Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu																																																																																																							
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Engine	Total Hp-hrs	CO (g/hp-hr)	NO _x (g/hp-hr)	PM ₁₀ (g/hp-hr)	PM _{2.5} (g/hp-hr)	SO ₂ (lb/hp-hr)	VOC (g/hp-hr)	Benzene (lb/mmBtu)	Toulene (lb/mmBtu)	Xylenes (lb/mmBtu)																																																																																																		
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ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																																																																																												
* Rig engine emission rates are based on a Tier II engine and rig generator emission rates are based on a Tier 0 engine.																																																																																																												
* All days, hours, and HP values above are based on typical industry values																																																																																																												

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Development Phase

Hydraulic Fracturing Flowback Emissions

Assumptions:

Estimated Frac flowback Rate:	10,000	Scf/hr	
Combustion Efficiency:	95.00	Percent (%)	
Event Duration:	100.00	Hours	
	379.49	Scf/lb-mol	- Typical/Constant Conversion Value

* Venting duration based on research and industry knowledge; please see report for additional information.

* Venting control based on Subpart OOOO requirements of 95% minimum control.

Control efficiency can be deleted if applicable.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr

** Multiply above equation by 0.02 if including 98% control efficiency

Un-combusted Componet Emissions:

Component	Mole % ^a	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year
Methane	88.9720	16.0	444.86	18.81	0.94
Ethane	5.7920	30.1	28.96	2.29	0.11
Propane	1.3650	44.1	6.83	0.79	0.04
i-Butane	0.3700	58.1	1.85	0.28	0.01
n-Butane	0.2610	58.1	1.31	0.20	0.01
i-Pentane	0.1550	72.2	0.78	0.15	0.01
n-Pentane	0.1020	72.2	0.51	0.10	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	0.73	0.17	0.01
Heptanes	0.0930	100.2	0.47	0.12	0.01
Octanes	0.0440	114.2	0.22	0.07	0.00
Nonanes	0.0160	128.3	0.08	0.03	0.00
Decanes +	0.0050	142.3	0.03	0.01	0.00
Benzene	0.0270	78.1	0.14	0.03	0.00
Toluene	0.0190	92.1	0.10	0.02	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	0.06	0.02	0.00
n-Hexane	0.1460	86.2	0.73	0.17	0.01
Nitrogen	0.0940	28.0	9.40	0.69	0.03
Carbon Dioxide	2.5280	44.0	252.80	29.32	1.47
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600	1492.8	13.80	2.14	0.11
HAPS Subtotal	0.2030	546.9	1.02	0.23	0.01
Total	100.1460	1645.0	749.82	53.26	2.66

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	8452.34	980.23	49.01
C2	5.79	550.24	63.81	3.19
C3	1.37	129.68	15.04	0.75
C4	0.63	59.95	6.95	0.35
C5+	0.76	72.58	8.42	0.42

CO₂ Total Emissions:	53.72	Tons/Event
N₂O Emissions:	1.13E-04	Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.37	3.80	0.19	AP-42 CH13.5-1
NO _x	0.068	0.70	0.03	AP-42 CH13.5-1
SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc. Wellsite Emissions	Base Location: Denver Basin Well Type: Oil Well																																												
Development Phase																																													
Workover Cementing Emissions																																													
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<p>Total Horsepower: 1,500 (Typical Value)</p> <p>Total: 11,760 Hp-hrs</p> <p>Fuel Usage: 724 Gallons of Diesel Total Fuel Usage: ((btu/hp-hr * hp-hrs) * gal/btu)</p>	<table><tr><th></th><th>Diesel EF Kg/mmBtu</th><th>Emissions lbs/Location</th><th>Emissions Tons/Location</th></tr><tr><td>CO2</td><td>73.96</td><td>16298.85</td><td>8.15</td></tr><tr><td>CH4</td><td>0.003</td><td>0.66</td><td>0.00</td></tr><tr><td>N2O</td><td>0.0006</td><td>0.13</td><td>0.00</td></tr></table>		Diesel EF Kg/mmBtu	Emissions lbs/Location	Emissions Tons/Location	CO2	73.96	16298.85	8.15	CH4	0.003	0.66	0.00	N2O	0.0006	0.13	0.00																												
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Emission Factors - Engine emission factors based on Tier II engines (typical values)																																													
Calculations: ton/year: (Total hp-hr * g-hp-hr) * lb-gram / lb-ton																																													

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Development Phase
Well Venting During Workover Events

Assumptions:

Significant gas venting only occurs on natural gas wells.

Estimated Venting Rate: 5,000 Scf/Event (Typical Value)
Combustion Efficiency: 0.00 Percent (%)
Event Quantity: 1.00 Event - Assumed one event
379.49 Scf/lb-mol - Typical/Constant Conversion Value

* Vented quantity based on research and industry knowledge; please see report for additional information.

Equations:

Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf-lb-mol)
** Multiply above equation by 0.02 if including 98% control efficiency

Component	Mole %	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Event
Methane	88.9720	16.0	4448.60	188.07	0.0940
Ethane	5.7920	30.1	289.60	22.95	0.0115
Propane	1.3650	44.1	68.25	7.93	0.0040
i-Butane	0.3700	58.1	18.50	2.83	0.0014
n-Butane	0.2610	58.1	13.05	2.00	0.0010
i-Pentane	0.1550	72.2	7.75	1.47	0.0007
n-Pentane	0.1020	72.2	5.10	0.97	0.0005
Other Pentanes	0.0000	70.1	0.00	0.00	0.0000
Hexanes	0.1460	86.2	7.30	1.66	0.0008
Heptanes	0.0930	100.2	4.65	1.23	0.0006
Octanes	0.0440	114.2	2.20	0.66	0.0003
Nonanes	0.0160	128.3	0.80	0.27	0.0001
Decanes +	0.0050	142.3	0.25	0.09	0.0000
Benzene	0.0270	78.1	1.35	0.28	0.0001
Toluene	0.0190	92.1	0.95	0.23	0.0001
Ethylbenzene	0.0000	106.2	0.00	0.00	0.0000
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.0000
Xylenes	0.0110	106.2	0.55	0.15	0.0001
n-Hexane	0.1460	86.2	7.30	1.66	0.0008
Nitrogen	0.0940	28.0	4.70	0.35	0.0002
Carbon Dioxide	2.5280	44.0	126.40	14.66	0.0073
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.0000

VOC Subtotal	2.7600	1492.8	138.00	21.44	0.0107
HAPS Subtotal	0.2030	546.9	10.15	2.32	0.0012
Total	100.1460	1645.0	5007.30	247.46	0.1237

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP. was a good representative analyses of general gas wells.

Flare Combustion GHG emissions:

	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year
C1	88.97	0.00	0.00	0.00
C2	5.79	0.00	0.00	0.00
C3	1.37	0.00	0.00	0.00
C4	0.63	0.00	0.00	0.00
C5+	0.76	0.00	0.00	0.00

CO₂ Total Emissions: 0.00 Tons/Event
N₂O Emissions: 5.67E-07 Tons/Event

Flare Combustion Emissions: Fuel Heating Value: 1028.00 btu/scf

	lbs/mmBTU	lbs/hour	Tons/event	
CO	0.00	0.00	0.00	AP-42 CH13.5-1
NOx	0.000	0.00	0.00	AP-42 CH13.5-1
SO ₂	-	0.00	0.000	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Development Phase

Wellsite Development Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks: 84 Trips/Location
 Light Duty Haul Trucks: 11 Trips/Location Total Trips: 95 Trips

Heavy Duty Haul Trucks: 67 Trips/Location
 Water Trucks: 24 Trips/Location Total Trips: 91 Trips

* Miles and number of trips based on research and industry knowledge;
 please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lb/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NO_x	7.44E-02	1.35E-01	1.98E-02	1.41E-01	2.77E-01
CO	1.98E-02	3.60E-02	3.16E-03	3.76E-02	7.37E-02
VOC	3.16E-03	5.75E-03	4.57E-05	6.00E-03	1.18E-02
SO₂	4.57E-05	8.32E-05	4.22E-03	8.68E-05	1.70E-04
PM₁₀	4.22E-03	7.68E-03	4.09E-03	8.02E-03	1.57E-02
PM_{2.5}	4.09E-03	7.44E-03	1.88E+00	7.77E-03	1.52E-02
CO₂	1.88E+00	3.41E+00	7.61E-05	3.56E+00	6.98E+00
CH₄	7.61E-05	1.38E-04	1.52E-05	1.45E-04	2.83E-04
N₂O	1.52E-05	2.77E-05	0.00E+00	2.89E-05	5.66E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite for calendar year 2012.

c Assumes maximum development scenario

Kleinfelder, Inc. Wellsite Emissions	Base Location: Denver Basin Well Type: Oil Well																																																																																																																																																																																		
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<p style="text-align: center;">**Wellhead gas combustion only for Williston Basin wells, due to the regularity of of pit flares combusting all gas coming from the wellhead. If gas being captured, change scf/hr value or hours of event value.</p> <p>Assumptions:</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 30%;">Estimated Gas Flow Rate:</td> <td style="width: 20%;">0</td> <td style="width: 20%;">Scf/hr</td> <td style="width: 30%;"></td> </tr> <tr> <td>Combustion Efficiency:</td> <td>0.00</td> <td>Percent (%)</td> <td></td> </tr> <tr> <td>Event Duration:</td> <td>0.00</td> <td>Hours</td> <td>- Estimated 3 months before sales line</td> </tr> <tr> <td></td> <td>379.49</td> <td>Scf/lb-mol</td> <td>- Typical/Constant Conversion Value</td> </tr> </table> <p style="text-align: center;">* It is assumed that all produced natural gas is sent to a sales line after the well is completed.</p> <p style="text-align: center;">Emissions (Tons/Year) = ((Scf/hr * Mole% / 100) * Mole Wt.) / (2000 * scf/lb-mol)) * hrs/yr</p> <p style="text-align: center;">** Multiply above equation by 0.05 if including 95% control efficiency</p> <p>Combusted Component Emissions:</p> <table border="1" style="width: 100%; border-collapse: collapse; text-align: center;"> <thead> <tr> <th>Component</th> <th>Mole % *</th> <th>Mole Weight lb/lb-mole</th> <th>Emissions Scf/hr</th> <th>Emissions lbs/hour</th> <th>Emissions Tons/Year</th> </tr> </thead> <tbody> <tr><td>Methane</td><td>88.9720</td><td>16.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethane</td><td>5.7920</td><td>30.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Propane</td><td>1.3650</td><td>44.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Butane</td><td>0.3700</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Butane</td><td>0.2610</td><td>58.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>i-Pentane</td><td>0.1550</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Pentane</td><td>0.1020</td><td>72.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Other Pentanes</td><td>0.0000</td><td>70.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hexanes</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Heptanes</td><td>0.0930</td><td>100.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Octanes</td><td>0.0440</td><td>114.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nonanes</td><td>0.0160</td><td>128.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Decanes +</td><td>0.0050</td><td>142.3</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Benzene</td><td>0.0270</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Toluene</td><td>0.0190</td><td>92.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Ethylbenzene</td><td>0.0000</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>2,2,4 Trimethylpentane</td><td>0.0000</td><td>78.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Xylenes</td><td>0.0110</td><td>106.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>n-Hexane</td><td>0.1460</td><td>86.2</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Nitrogen</td><td>0.0940</td><td>28.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Carbon Dioxide</td><td>2.5280</td><td>44.0</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td>Hydrogen Sulfide</td><td>0.0000</td><td>34.1</td><td>0.00</td><td>0.00</td><td>0.00</td></tr> <tr><td colspan="6"> </td></tr> <tr> <td>VOC Subtotal</td> <td>2.7600</td> <td>1492.8</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>HAPS Subtotal</td> <td>0.2030</td> <td>546.9</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> <tr> <td>Total</td> <td>100.1460</td> <td>1645.0</td> <td>0.00</td> <td>0.00</td> <td>0.00</td> </tr> </tbody> </table>		Estimated Gas Flow Rate:	0	Scf/hr		Combustion Efficiency:	0.00	Percent (%)		Event Duration:	0.00	Hours	- Estimated 3 months before sales line		379.49	Scf/lb-mol	- Typical/Constant Conversion Value	Component	Mole % *	Mole Weight lb/lb-mole	Emissions Scf/hr	Emissions lbs/hour	Emissions Tons/Year	Methane	88.9720	16.0	0.00	0.00	0.00	Ethane	5.7920	30.1	0.00	0.00	0.00	Propane	1.3650	44.1	0.00	0.00	0.00	i-Butane	0.3700	58.1	0.00	0.00	0.00	n-Butane	0.2610	58.1	0.00	0.00	0.00	i-Pentane	0.1550	72.2	0.00	0.00	0.00	n-Pentane	0.1020	72.2	0.00	0.00	0.00	Other Pentanes	0.0000	70.1	0.00	0.00	0.00	Hexanes	0.1460	86.2	0.00	0.00	0.00	Heptanes	0.0930	100.2	0.00	0.00	0.00	Octanes	0.0440	114.2	0.00	0.00	0.00	Nonanes	0.0160	128.3	0.00	0.00	0.00	Decanes +	0.0050	142.3	0.00	0.00	0.00	Benzene	0.0270	78.1	0.00	0.00	0.00	Toluene	0.0190	92.1	0.00	0.00	0.00	Ethylbenzene	0.0000	106.2	0.00	0.00	0.00	2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00	Xylenes	0.0110	106.2	0.00	0.00	0.00	n-Hexane	0.1460	86.2	0.00	0.00	0.00	Nitrogen	0.0940	28.0	0.00	0.00	0.00	Carbon Dioxide	2.5280	44.0	0.00	0.00	0.00	Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00							VOC Subtotal	2.7600	1492.8	0.00	0.00	0.00	HAPS Subtotal	0.2030	546.9	0.00	0.00	0.00	Total	100.1460	1645.0	0.00	0.00	0.00
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Flare Combustion GHG emissions:					
	Component Molar Ratio (%)	Emissions Scf/hr	Emissions lbs/hr	Emissions Tons/Year	
C1	88.97	0.00	0.00	0.00	
C2	5.79	0.00	0.00	0.00	
C3	1.37	0.00	0.00	0.00	
C4	0.63	0.00	0.00	0.00	
C5+	0.76	0.00	0.00	0.00	
CO₂ Total Emissions:				0.00	Tons/Year
N₂O Emissions:				0.00E+00	Tons/Year
Flare Combustion Emissions:					
		Fuel Heating Value:	1028.00	btu/scf	
		lbs/mmBTU	lbs/hour	Tons/event	
	CO	0.00	0.00	0.00	AP-42 CH13.5-1
	NOx	0.000	0.00	0.00	AP-42 CH13.5-1
	SO ₂	-	0.00	0.00	*Based on H ₂ S 34 mol weight and SO ₂ 64 mol weight

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Production Phase

Production Equipment Fugitive Component Emissions

Assumptions:

Components Counts:

	Fugitive Components				
Component *	Valves	Flanges	Connectors	OE Lines	Other
Count	18	32	28	0	0
Emissions Factor (scf/hr) ^b	0.050	0.003	0.007	0.050	0.300

* Fugitive component counts for natural gas wells from Subpart W, Table W-1B

* Fugitive component counts for oil wells from Subpart W, Table W-1C

Annual Equipment Run Time: 8760 Hours/Year 379.49 Scf/lb-mol

Component	Mole % ^a	Mole Weight lb/lb-mol	Emissions Scf/Year ^b	Emissions lbs/Year	Emissions Tons/Year
Methane	88.9720	16.0	9,290.4	392.8	0.20
Ethane	5.7920	30.1	604.8	47.9	0.02
Propane	1.3650	44.1	142.5	16.6	0.01
i-Butane	0.3700	58.1	38.6	5.9	0.00
n-Butane	0.2610	58.1	27.3	4.2	0.00
i-Pentane	0.1550	72.2	16.2	3.1	0.00
n-Pentane	0.1020	72.2	10.7	2.0	0.00
Other Pentanes	0.0000	70.1	0.00	0.00	0.00
Hexanes	0.1460	86.2	15.2	3.5	0.00
Heptanes	0.0930	100.2	9.7	2.6	0.00
Octanes	0.0440	114.2	4.6	1.4	0.00
Nonanes	0.0160	128.3	1.7	0.6	0.00
Decanes +	0.0050	142.3	0.5	0.2	0.00
Benzene	0.0270	78.1	2.8	0.6	0.00
Toluene	0.0190	92.1	2.0	0.5	0.00
Ethylbenzene	0.0000	106.2	0.00	0.00	0.00
2,2,4 Trimethylpentane	0.0000	78.1	0.00	0.00	0.00
Xylenes	0.0110	106.2	1.1	0.3	0.00
n-Hexane	0.1460	86.2	15.2	3.5	0.00
Nitrogen	0.0940	28.0	9.8	0.7	0.00
Carbon Dioxide	2.5280	44.0	264.0	30.6	0.02
Hydrogen Sulfide	0.0000	34.1	0.00	0.00	0.00

VOC Subtotal	2.7600			44.77	0.02
HAPS Subtotal	0.2030			4.85	0.00
Total	100.1460			516.78	0.26

Calculation

$$\text{lb/hr} = (\text{Mol \%} * \text{SumSCF/yr}) / \text{scf/lb-mol}$$

^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.

^b Fugitive emission factors from Subpart W, Table W-1A

Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Production Phase
Process Heater Emissions

Wellsite Heater Inventory:

Heater Treater	Heating Value (Mbtu/hr)	Fuel Consumption (MMscf/yr)	
	750	6.44	* Heater treater size based on industry standard

Annual Run Time:	8760	Hours/Year
Fuel Gas Heat Value:	1,020	Btu/scf (Standard heating value from AP-42)

Equations:

$$\text{Fuel Consumption (MMscf/yr)} = \frac{\text{Heater Size (MBtu/hr)} * 1,000 \text{ (Btu/MBtu)} * \text{Hours of Operation (hrs/yr)}}{\text{Fuel Heat Value (Btu/scf)} * 1,000,000 \text{ (scf/MMscf)}}$$

$$\text{NOx/CO/TOC Emissions (tons/yr)} = \frac{\text{AP-42 E.Factor (lbs/MMscf)} * \text{Fuel Consumption (MMscf/yr)} * \text{Fuel heating Value (Btu/scf)}}{2,000 \text{ (lbs/ton)} * 1,020 \text{ (Btu/scf - Standard Fuel Heating Value)}}$$

	Emission Factor (lb/MMscf)	Heater Treater Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year)	Total Emissions (Tons/Year) ^e
<i>Criteria Pollutants & VOC</i>						
NOx ^a	100	0.3221	0.0000	0.0000	0.0000	0.3221
CO ^a	84.0	0.2705	0.0000	0.0000	0.0000	0.2705
VOC	5.5	0.0177	0.0000	0.0000	0.0000	0.0177
SO ₂ ^b	0.00	0.0000	0.0000	0.0000	0.0000	0.0000
TSP ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
PM ₁₀ ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
PM _{2.5} ^c	7.60	0.0245	0.0000	0.0000	0.0000	0.0245
<i>Hazardous Air Pollutants</i>						
Benzene ^d	2.10E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Toluene ^d	3.40E-03	0.0000	0.0000	0.0000	0.0000	0.0000
Hexane ^d	1.80	0.0058	0.0000	0.0000	0.0000	0.0058
Formaldehyde ^d	7.50E-02	0.0002	0.0000	0.0000	0.0000	0.0002
<i>Greenhouse Gases</i>						
CO ₂ ^f	120,162	386.9918	0.0000	0.0000	0.0000	386.9918
CH ₄ ^f	2.27	0.0073	0.0000	0.0000	0.0000	0.0073
N ₂ O ^f	0.23	0.0007	0.0000	0.0000	0.0000	0.0007

a AP-42 Table 1.4-1, Emission Factors for Natural Gas Combustion, 7/98

b Assumes produced gas contains no sulfur

c AP-42 Table 1.4-2, Emission Factors for Natural Gas Combustion, 7/98 (All Particulates are PM_{1.0})

d AP-42 Table 1.4-3, Emission Factors for Organic Compounds from Natural Gas Combustion, 7/98

e Assumes maximum development scenario

f Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu.

Kleinfelder, Inc. Wellsite Emissions			Base Location: Denver Basin Well Type: Oil Well			
Production Phase						
Atmospheric Oil Tank Flashing Emissions						
Assumptions:						
Production Estimate:		125	barrels/day			
Production Days:		365	Days/Year			
Flasing Gas-to-Oil Ratio:		45	Scf/bbl	379.49 Scf/lb-mol		
Control Efficiency:		95	Percent (%)			
Flashing Gas Composition:						
Component	Mole %	Mole Weight (lb/lb-mol)	Emissions (Uncontrolled) Scf/Year	Emissions (Uncontrolled) lbs/Year	Emissions (Uncontrolled) Tons/Year	Emissions (Controlled) Tons/Year
Methane	23.6778	16.043	486134.8313	20551.4272	10.2757	0.5138
Ethane	31.6716	30.07	650257.5375	51525.0577	25.7625	1.2881
Propane	27.0752	44.097	555887.7	64594.5345	32.2973	1.6149
i-Butane	2.3870	58.123	49008.09375	7506.1199	3.7531	0.1877
n-Butane	6.1325	58.123	125907.8906	19284.1559	9.6421	0.4821
i-Pentane	0.9352	72.150	19200.825	3650.5297	1.8253	0.0913
n-Pentane	1.5003	72.150	30803.03438	5856.3834	2.9282	0.1464
Other Pentanes	0.6754	70.100	13867.52484	2561.6314	1.2808	0.0640
Hexanes	2.2516	86.177	46228.1625	10497.7848	5.2489	0.2624
Heptanes	0.7869	100.204	16156.04063	4265.9883	2.1330	0.1066
Octanes	0.1469	114.231	3016.040625	907.8641	0.4539	0.0227
Nonanes	0.0463	128.258	950.596875	321.2776	0.1606	0.0080
Decanes +	0.0105	142.285	215.578125	80.8283	0.0404	0.0020
Benzene	0.1540	78.120	3161.8125	650.8756	0.3254	0.0163
Toluene	0.0709	92.130	1455.665625	353.3966	0.1767	0.0088
Ethylbenzene	0.0034	106.160	69.80625	19.5279	0.0098	0.0005
2,2,4 Trimethylpentane	0.0253	78.120	519.440625	106.9296	0.0535	0.0027
Xylenes	0.0219	106.160	449.634375	125.7825	0.0629	0.0031
n-Hexane	0.9119	86.177	18722.44688	4251.6122	2.1258	0.1063
Nitrogen	0.0000	28.013	0	0.0000	0.0000	0.0000
Carbon Dioxide	2.1907	44.010	44977.80938	5216.1411	2.6081	0.1304
Hydrogen Sulfide	0.0000	34.080	0	0.0000	0.0000	0.0000
VOC Subtotal	43.14				62.52	3.13
HAPS Subtotal	1.19				2.75	0.14
Total	100.6753				101.1639	5.0582
Calculation:						
Scf/yr = (Mol% * scf/bbl * bbl/day * days/yr) / 100						
lb/yr = (scf/yr * mol wt.) / scf/lb-mol						
* Production and gas to oil ratio based on basin specific differences. Please see "Gas Stream Molar Ratios" tab and report for additional information.						

Kleinfelder, Inc. Wellsite Emissions	Base Location: Denver Basin Well Type: Oil Well																								
Production Phase																									
Wellsite Produced Water Tanks Venting																									
<p>Assumptions:</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 40%;">Average Estimated Water Production:</td> <td style="width: 20%; text-align: center;">11000</td> <td style="width: 40%;">Barrels Per Year</td> </tr> <tr> <td>Number of Water Tanks:</td> <td style="text-align: center;">1</td> <td>Tanks</td> </tr> <tr> <td>VOC Emissions Factor:</td> <td style="text-align: center;">0.2620</td> <td>lbs/bbl</td> </tr> <tr> <td>n-Hexane Emission Factor:</td> <td style="text-align: center;">0.0220</td> <td>lbs/bbl</td> </tr> <tr> <td>Benzene Emission Factor:</td> <td style="text-align: center;">0.0070</td> <td>lbs/bbl</td> </tr> </table> <p>Calculations:</p> <table border="1" style="margin-left: auto; margin-right: auto; border-collapse: collapse; text-align: center;"> <tr> <td style="width: 33%;">VOC Emissions:</td> <td style="width: 33%;">1.441</td> <td style="width: 33%;">Tons/Year</td> </tr> <tr> <td>Hexane Emissions:</td> <td>0.121</td> <td>Tons/Year</td> </tr> <tr> <td>Benzene Emissions:</td> <td>0.0385</td> <td>Tons/Year</td> </tr> </table> <p style="margin-top: 20px;"> * Production conservatively based on estimated industry single well average * Emission factors based on only known lb/bbl factor, which was developed by the Colorado Department of Health and Environment (PS Memo 09-02). </p>		Average Estimated Water Production:	11000	Barrels Per Year	Number of Water Tanks:	1	Tanks	VOC Emissions Factor:	0.2620	lbs/bbl	n-Hexane Emission Factor:	0.0220	lbs/bbl	Benzene Emission Factor:	0.0070	lbs/bbl	VOC Emissions:	1.441	Tons/Year	Hexane Emissions:	0.121	Tons/Year	Benzene Emissions:	0.0385	Tons/Year
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Production Phase
Truck Loading Emissions

AP - 42, Chapter 5.2

$$L_L = 12.46 \times S \times P \times M / T$$

L_L = Loading Loss Emission Factor (lbs VOC/1000 gal loaded)
S = Saturation Factor
P = True Vapor Pressure of the Loaded Liquid (psia)
M = Vapor Molecular Weight of the Loaded Liquid (lbs/lbmol)
T = Temperature of Loaded Liquid (°R)

$$\text{VOC Emissions (tpy)} = \frac{L_L (\text{lbs VOC}/1000 \text{ gal}) \times 42 \text{ gal/bbl} \times 365 \text{ days/year} \times \text{production (bbl/day)}}{1000 \text{ gal} \times 2000 \text{ lbs/ton}}$$

S ¹	P (psia) ²	M (lb/lbmol) ³	T (°F) ⁴	T (°R)	L _L (lb/1000 gal)	Production (bbl/day)	VOC (tpy)
0.6	2.30	50.00	50.00	509.67	1.69	125.0	1.62

- Notes:
1. Saturation factor from AP-42, Table 5.2-1 (Submerged loading: dedicated normal service)
 2. True vapor pressure is estimated from AP-42, Table 7.1-2 assuming an average daily temperature of either 40 or 50 deg F and an RVP of 10.0.
 3. Molecular weight liquid vapor is estimated from AP-42, Table 7.1-2 assuming an RVP of 10.0.
 4. Temperature based on the annual average temperature for basin location (either 40 or 50 degrees F based on options provided in AP-42 Table 7.1-2)

Kleinfelder, Inc. Wellsite Emissions	Base Location: Denver Basin Well Type: Oil Well																																																																																																											
Production Phase Pumpjack Unit Emissions																																																																																																												
<p>Assumptions:</p> <p style="text-align: center;">*Pumpjack engines only included at oil wells*</p> <table style="margin-left: auto; margin-right: auto;"> <tr> <td>Pumpjack Horsepower Rating:</td> <td>65.0</td> <td>Horsepower</td> </tr> <tr> <td>Load Factor:</td> <td>0.54</td> <td></td> </tr> <tr> <td>Brake Specific Fuel Consumption:</td> <td>8,000</td> <td>Btu/hp-hr</td> </tr> <tr> <td>Annual Operation:</td> <td>8,760</td> <td>Hours/Year</td> </tr> </table> <p>Equations:</p> <p style="text-align: center;"> Emissions (lbs/hr) = Emission Factor (g/hp-hr) * Power (hp) 453.6 g/lb </p> <table border="1" style="width: 100%; border-collapse: collapse; margin-top: 20px;"> <thead> <tr> <th style="text-align: center;">Pollutant</th> <th style="text-align: center;">Emission Factor ^a (lb/MMBtu)</th> <th style="text-align: center;">Emission Factor ^a (g/hp-hr)</th> <th style="text-align: center;">Emissions (lb/hr)</th> <th style="text-align: center;">Emissions (Tons/Year)</th> </tr> </thead> <tbody> <tr><td colspan="5"><i>Criteria Pollutants & VOC</i></td></tr> <tr><td>NOx</td><td></td><td style="text-align: center;">2.80</td><td style="text-align: center;">0.22</td><td style="text-align: center;">0.9490</td></tr> <tr><td>CO</td><td></td><td style="text-align: center;">4.80</td><td style="text-align: center;">0.37</td><td style="text-align: center;">1.6269</td></tr> <tr><td>VOC</td><td style="text-align: center;">0.12</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0337</td><td style="text-align: center;">0.1476</td></tr> <tr><td>PM₁₀ ^b</td><td style="text-align: center;">4.83E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">1.36E-02</td><td style="text-align: center;">5.94E-02</td></tr> <tr><td>PM_{2.5} ^b</td><td style="text-align: center;">4.83E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">1.36E-02</td><td style="text-align: center;">5.94E-02</td></tr> <tr><td>SO₂</td><td style="text-align: center;">5.88E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0002</td><td style="text-align: center;">0.0007</td></tr> <tr><td colspan="5"><i>Hazardous Air Pollutants</i></td></tr> <tr><td>Benzene</td><td style="text-align: center;">1.94E-03</td><td style="text-align: center;">-</td><td style="text-align: center;">5.45E-04</td><td style="text-align: center;">2.39E-03</td></tr> <tr><td>Toluene</td><td style="text-align: center;">9.63E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">2.70E-04</td><td style="text-align: center;">1.18E-03</td></tr> <tr><td>Ethylbenzene</td><td style="text-align: center;">1.08E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">3.03E-05</td><td style="text-align: center;">1.33E-04</td></tr> <tr><td>Xylenes</td><td style="text-align: center;">2.68E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">7.53E-05</td><td style="text-align: center;">3.30E-04</td></tr> <tr><td>Formaldehyde</td><td style="text-align: center;">5.52E-02</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0155</td><td style="text-align: center;">0.0679</td></tr> <tr><td>n-Hexane</td><td style="text-align: center;">4.45E-04</td><td style="text-align: center;">-</td><td style="text-align: center;">1.25E-04</td><td style="text-align: center;">5.47E-04</td></tr> <tr><td colspan="5"><i>Greenhouse Gases</i></td></tr> <tr><td>CO₂ ^c</td><td style="text-align: center;">117</td><td style="text-align: center;">-</td><td style="text-align: center;">32.82</td><td style="text-align: center;">144</td></tr> <tr><td>CH₄</td><td style="text-align: center;">0.002</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0006</td><td style="text-align: center;">0.0027</td></tr> <tr><td>N₂O</td><td style="text-align: center;">0.0002</td><td style="text-align: center;">-</td><td style="text-align: center;">0.0001</td><td style="text-align: center;">0.0003</td></tr> </tbody> </table> <p style="margin-top: 20px;"> ^a AP-42 Table 3.2-3 Uncontrolled Emission Factors for 4-Stroke Rich-Burn Engines, 7/00; and Subpart JJJJ for NOX and CO emission rates. ^b PM = sum of PM filterable and PM condensable ^c Subpart W - Part 98.233(z)(1) indicates the use of Table C-1 and Table C-2 for fuel combustion of stationary and portable equipment. Table C-1 provides an EF for natural gas combustion of 53.02 kg CO₂/mmBtu. Table C-2 provides an EF for natural gas combustion for CH₄ as 1.0E-03 kg/MMBtu and for N₂O as 1.0E-04 kg/MMBtu. </p> <p style="margin-top: 10px;"> - Network website for the 1999 National-Scale Air Toxics Assessment at http://www.epa.gov/ttn/atw/nata1999/nsata99.html </p>		Pumpjack Horsepower Rating:	65.0	Horsepower	Load Factor:	0.54		Brake Specific Fuel Consumption:	8,000	Btu/hp-hr	Annual Operation:	8,760	Hours/Year	Pollutant	Emission Factor ^a (lb/MMBtu)	Emission Factor ^a (g/hp-hr)	Emissions (lb/hr)	Emissions (Tons/Year)	<i>Criteria Pollutants & VOC</i>					NOx		2.80	0.22	0.9490	CO		4.80	0.37	1.6269	VOC	0.12	-	0.0337	0.1476	PM₁₀ ^b	4.83E-02	-	1.36E-02	5.94E-02	PM_{2.5} ^b	4.83E-02	-	1.36E-02	5.94E-02	SO₂	5.88E-04	-	0.0002	0.0007	<i>Hazardous Air Pollutants</i>					Benzene	1.94E-03	-	5.45E-04	2.39E-03	Toluene	9.63E-04	-	2.70E-04	1.18E-03	Ethylbenzene	1.08E-04	-	3.03E-05	1.33E-04	Xylenes	2.68E-04	-	7.53E-05	3.30E-04	Formaldehyde	5.52E-02	-	0.0155	0.0679	n-Hexane	4.45E-04	-	1.25E-04	5.47E-04	<i>Greenhouse Gases</i>					CO₂ ^c	117	-	32.82	144	CH₄	0.002	-	0.0006	0.0027	N₂O	0.0002	-	0.0001	0.0003
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Kleinfelder, Inc. Wellsite Emissions	Base Location: Denver Basin Well Type: Oil Well																								
Production Phase																									
Wellsite Dehydrator Emissions																									
<p>Assumptions:</p> <p>Number of Dehy Units: 0 Units</p> <p>Calculations:</p> <p>Calculations and specifications derived from Pinedale Anticline Final SEIS GRI-GLYCalc 4.0 operated with: 4 MMSCFD, 0.32 gpm glycol flow, average representative gas analysis, and 95% control efficiency</p> <p>Emissions:</p> <table border="1" data-bbox="553 987 1062 1478"> <thead> <tr> <th>Species</th><th>Total Project Emissions (tons/year)</th></tr> </thead> <tbody> <tr> <td>Total VOC</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Hazardous Air Pollutants</i></td></tr> <tr> <td>Benzene</td><td>0.000</td></tr> <tr> <td>Toluene</td><td>0.000</td></tr> <tr> <td>Ethylbenzene</td><td>0.000</td></tr> <tr> <td>Xylenes</td><td>0.000</td></tr> <tr> <td>n-Hexane</td><td>0.000</td></tr> <tr> <td colspan="2"><i>Greenhouse Gases</i></td></tr> <tr> <td>CO₂</td><td>0.000</td></tr> <tr> <td>CH₄^a</td><td>0.000</td></tr> <tr> <td>N₂O</td><td>0.000</td></tr> </tbody> </table> <p>Note, no greenhouse gas emissions included for dehydrator in Pinedale EIS</p>		Species	Total Project Emissions (tons/year)	Total VOC	0.000	<i>Hazardous Air Pollutants</i>		Benzene	0.000	Toluene	0.000	Ethylbenzene	0.000	Xylenes	0.000	n-Hexane	0.000	<i>Greenhouse Gases</i>		CO₂	0.000	CH₄^a	0.000	N₂O	0.000
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Kleinfelder, Inc.
Wellsite Emissions

Base Location: Denver Basin
Well Type: Oil Well

Construction Phase

Roadway Construction Traffic Tailpipe Emissions

Assumptions:

Average Round Trip Distance: 40.0 Miles/Trip Average

Light Duty Pickup Trucks: 50 Trips/Location
 Light Duty Haul Trucks 0 Trips/Location Total Trips: 50 Trips

Heavy Duty Haul Trucks 2 Trips/Location
 Water Trucks 40 Trips/Location Total Trips: 42 Trips

* Miles and number of trips based on research and industry knowledge;
 please see report for additional information.

Equations:

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (g/mile)} * \# \text{ Trips} * \text{Trip Distance (miles)}}{2000 \text{ (lb/tons)}}$$

Construction Vehicles	Heavy Haul Trucks		Light Duty Pickups		Total
	E. Factor ^a (lb/mile)	Emissions (Tons/Location)	E. Factor ^b (lb/mile)	Emissions (Tons/Location)	Emissions (Tons/Location)
NO_x	7.44E-02	6.25E-02	7.39E-03	7.39E-03	6.99E-02
CO	1.98E-02	1.66E-02	7.26E-02	7.26E-02	8.92E-02
VOC	3.16E-03	2.65E-03	3.54E-03	3.54E-03	6.19E-03
SO₂	4.57E-05	3.84E-05	2.83E-05	2.83E-05	6.67E-05
PM₁₀	4.22E-03	3.54E-03	1.94E-04	1.94E-04	3.74E-03
PM_{2.5}	4.09E-03	3.44E-03	1.79E-04	1.79E-04	3.61E-03
CO₂	1.88E+00	1.58E+00	1.13E+00	1.13E+00	2.70E+00
CH₄	7.61E-05	6.39E-05	4.56E-05	4.56E-05	1.10E-04
N₂O	1.52E-05	1.28E-05	9.13E-06	9.13E-06	2.19E-05

a Emission factors developed using EPA MOVES model, assuming Heavy-Heavy Duty Diesel Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

b Emission factors developed using EPA MOVES model, assuming Light Heavy Duty Gasoline Trucks, traveling 15 mph onsite in typical oil and gas development area, for calendar year 2012.

c Assumes maximum development scenario

Kleinfelder, Inc. Wellsite Emissions			Base Location: Denver Basin Well Type: Oil Well				
Production Phase							
Pneumatic Device Emissions							
Wellsite Pneumatic Inventory:							
Devices:		Classification	Quantity	Emission Factor (Scf/hr/unit)			
			0	0.00			
			0	0.00			
			0	0.00			
Pumps:				0.00			
Annual Equipment Run Time:		8760	Hours/Year	379.49 Scf/lb-mol			
Pneumatic Device Control: ^b		0	Percent				
* Low bleed and intermittent bleed emission factors (scf/hr) based on Subpart W, Table W-1A							
* Quantity of devices based on typical industry values							
Component	Mole %	Mole Weight lb/lb-mol	(None) Tons/Year	(None) Tons/Year	(None) Tons/Year	Pneumatic Pumps Tons/Year	Total Tons/Year
Methane	88.9720	16.0	0.000	0.000	0.000	0.000	0.000
Ethane	5.7920	30.1	0.000	0.000	0.000	0.000	0.000
Propane	1.3650	44.1	0.000	0.000	0.000	0.000	0.000
i-Butane	0.3700	58.1	0.000	0.000	0.000	0.000	0.000
n-Butane	0.2610	58.1	0.000	0.000	0.000	0.000	0.000
i-Pentane	0.1550	72.2	0.000	0.000	0.000	0.000	0.000
n-Pentane	0.1020	72.2	0.000	0.000	0.000	0.000	0.000
Other Pentanes	0.0000	70.1	0.000	0.000	0.000	0.000	0.000
Hexanes	0.1460	86.2	0.000	0.000	0.000	0.000	0.000
Heptanes	0.0930	100.2	0.000	0.000	0.000	0.000	0.000
Octanes	0.0440	114.2	0.000	0.000	0.000	0.000	0.000
Nonanes	0.0160	128.3	0.000	0.000	0.000	0.000	0.000
Decanes +	0.0050	142.3	0.000	0.000	0.000	0.000	0.000
Benzene	0.0270	78.1	0.000	0.000	0.000	0.000	0.000
Toluene	0.0190	92.1	0.000	0.000	0.000	0.000	0.000
Ethylbenzene	0.0000	106.2	0.000	0.000	0.000	0.000	0.000
2,2,4 Trimethylpentane	0.0000	78.1	0.000	0.000	0.000	0.000	0.000
Xylenes	0.0110	106.2	0.000	0.000	0.000	0.000	0.000
n-Hexane	0.1460	86.2	0.000	0.000	0.000	0.000	0.000
Nitrogen	0.0940	28.0	0.000	0.000	0.000	0.000	0.000
Carbon Dioxide	2.5280	44.0	0.000	0.000	0.000	0.000	0.000
Hydrogen Sulfide	0.0000	34.1	0.000	0.000	0.000	0.000	0.000
VOC Subtotal	2.8	1492.8	0.00	0.00	0.00	0.00	0.00
HAPS Subtotal	0.2	546.9	0.00	0.00	0.00	0.00	0.00
Total	100.1	1645.0	0.00	0.00	0.00	0.00	0.00
^a Gas analyses for gas wells are based on research done on different RMP's and private industry analyses. Research showed that the representative average gas analyses used by the River Valley RMP was a good representative analyses of general gas wells.							
^b 98% control input is a result of the Wyoming Department of Environment Quality requirement, and only pertains to the Upper Green River Basin.							

Exhibit 3

Attachment F

DRAFT OIL AND GAS AIR EMISSIONS INVENTORY REPORT FOR SEVEN LEASE PARCELS IN THE BLM ROYAL GORGE FIELD OFFICE

Prepared for:

BLM
Colorado State Office and Royal Gorge Field Office
Colorado

Prepared by:

URS
URS Group, Inc.

Program Office:
9901 IH-10, Suite 350
San Antonio, Texas, 78230

URS Project 22243007

July 2013

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<u>2.1 Potential Well Development</u>	1
<u>2.2 Potential Oil and Gas Activities</u>	2
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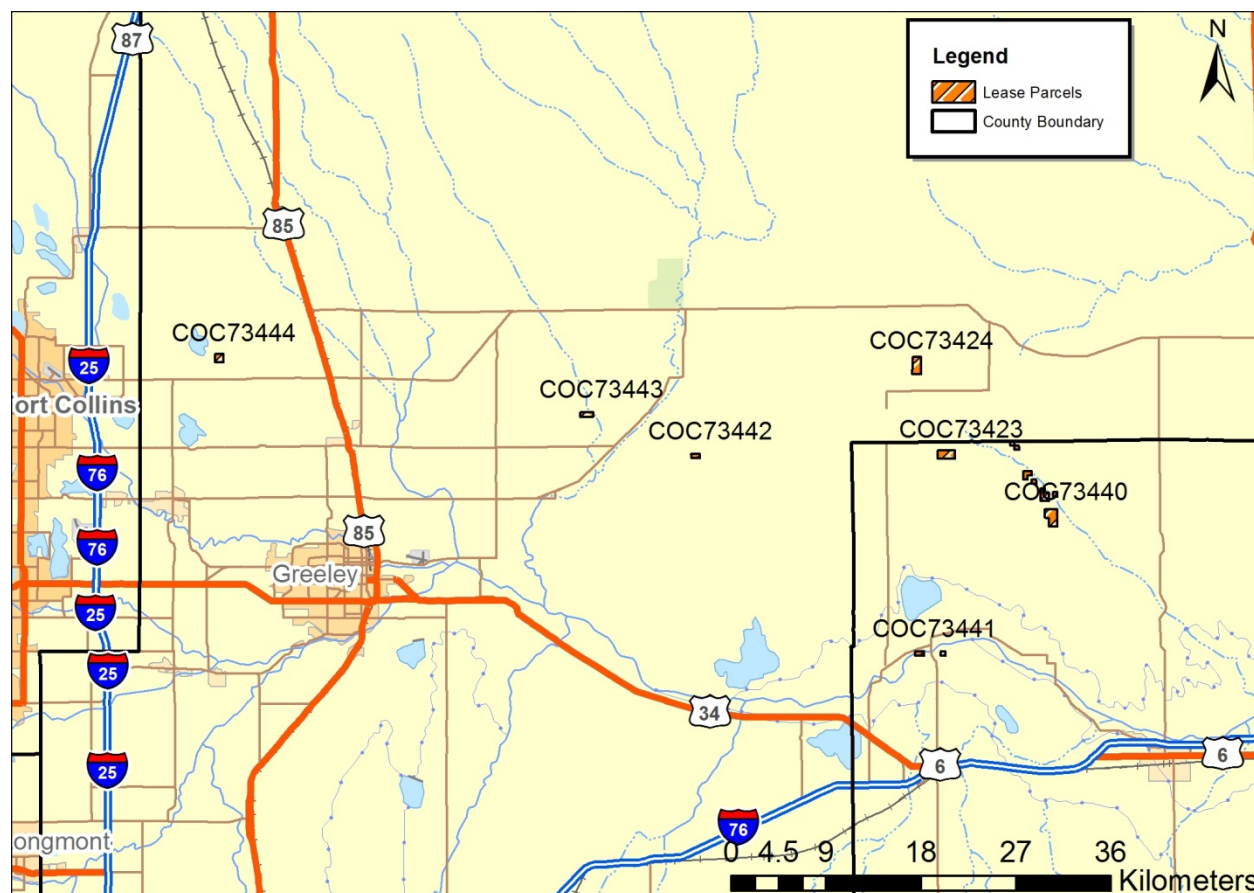
LIST OF ACRONYMS AND ABBREVIATIONS

AP-42	<i>Compilation of Air Pollutant Emission Factors</i>
APD	Application for Permit to Drill
API	American Petroleum Institute
bbls	Barrels
BLM	Bureau of Land Management
CH ₄	Methane
CO	Carbon monoxide
CO ₂	Carbon dioxide
COGCC	Colorado Oil and Gas Conservation Commission
CSO	Colorado State Office
Mscf	Thousands of standard cubic feet
NAA	Non-Attainment Area
NH ₃	Ammonia
N ₂ O	Nitrous oxides
NO _x	Oxides of nitrogen
O&G	Oil and Gas
PM	Particulate matter
PM ₁₀	Particulate matter less than or equal to 10 microns in size
PM _{2.5}	Particulate matter less than or equal to 2.5 microns in size
PSICC	Pike and San Isabel National Forests and Cimarron and Comanche National Grasslands
RFD	Reasonably foreseeable development
RGFO	Royal Gorge Field Office
SO ₂	Sulfur dioxide
tpy	Tons per year
URS	URS Group, Inc.
USEPA	U.S. Environmental Protection Agency
VOC	Volatile organic compound

PROJECT INTRODUCTION AND STUDY AREA

This oil and gas (O&G) emissions inventory report identifies the data and methodologies used in developing air emissions inventories for potential oil and gas development and production activities on seven (7) specific lease parcels in the Bureau of Land Management (BLM) Royal Gorge Field Office (RGFO). These seven parcels are part of the twelve (12) lease parcels in eastern Colorado referred to in the Stipulation and Order entered into by WildEarth Guardians and the BLM (WildEarth 2012) and for this report will further be known as “Study” or “Project”. The emissions inventories include quantified potential emissions based on the 2012 BLM RGFO Reasonable Foreseeable Development (RFD) document (BLM 2012).

For emissions inventory domain purposes, the Study Area focuses on the seven lease parcels in the BLM RGFO in Colorado. The RGFO administers over 680,000 surface acres of public land along the Colorado Front Range and 6.8 million sub-surface acres. This Field Office covers approximately the eastern half of Colorado and includes a variety of terrain. The Project emissions inventory development will focus on potential oil and gas activities on the seven lease parcels in the RGFO. A map showing the locations of the seven BLM lease parcels is presented below (Map 1-1).



Map 0-1. Locations of Seven BLM Lease Parcels

The number of active wells for each Township that contains one of the seven lease parcels is shown below in Table 1-1 (data taken from Figure 5b of the RFD [BLM 2012]). Also shown in this table are the number of active wells in the county in 2011, as well as the 2011 oil, gas, and water production for each of the two counties containing the seven lease parcels (COGCC 2013). In order to provide a background of the emissions levels in the area of the lease parcels, Table 1-2 provides county level emissions inventories in tons per year (tpy) for Weld and Morgan counties taken from the 2008 National Emissions Inventory (USEPA 2013).

Table 0-1. Active Wells and Production Values

Parcel Serial #	Township	Number of Active Wells in Township in 2011	County	Number of Active Wells in County in 2011	2011 Average Monthly Oil Production (bbls)	2011 Average Monthly Gas Production (Mscf)	2011 Average Monthly Water Production (bbls)
COC73423	Township 6 North Range 60 West	6	Morgan	252	9,159	10,946	265,862
COC73440	Township 6 North Range 59 West	4					
COC73441	Township 4 North Range 60 West	0					
COC73424	Township 7 North Range 60 West	8	Weld	22,323	2,220,768	19,964,793	954,887
COC73442	Township 6 North Range 62 West	54					
COC73443	Township 7 North Range 63 West	50					
COC73444	Township 7 North Range 67 West	21					

bbls = barrels

Mscf = thousands of standard cubic feet

Source: COGCC 2011 County Production Report

Table 0-2. 2008 County Level Emissions Inventories (tpy)

County	PM ₁₀	PM _{2.5}	CO	NO _x	SO ₂	VOC	CO ₂	CH ₄	N ₂ O	NH ₃	HAPs
Morgan	6,880	1,529	10,471	9,561	13,466	10,234	306,257	22	10	5,765	2,232
Weld	28,851	5,962	60,876	20,088	352	52,991	1,683,038	137	66	17,042	7,389

PM = Particulate matter

PM₁₀ = Particulate matter less than or equal to 10 microns in size

PM_{2.5} = Particulate matter less than or equal to 2.5 microns in size

CO = Carbon monoxide

NO_x = Oxides of nitrogen

SO₂ = Sulfur dioxide

VOC = Volatile organic compounds

CO₂ = Carbon dioxide

CH₄ = Methane

N₂O = Nitrous oxide

NH₃ = Ammonia

HAPs = Hazardous air pollutants

Source: USEPA 2008 NEI

EMISSIONS INVENTORY METHODOLOGY

This section describes the data sources and methods that were used to develop the seven lease parcel-specific emission inventories.

POTENTIAL WELL DEVELOPMENT

Potential well development was estimated using data from the 2012 BLM RGFO RFD and is shown in Table 2-1. Map 2-1 shows oil and gas development potential and projected drilling densities for the years 2011 through 2030 for each Township in the RGFO (Figure 17, 2012 BLM). The minimum and maximum number of potential wells per Township was determined for each lease parcel based on this figure. The average acres disturbed per well was calculated using Table 14a of the RFD document along with the expected percentages of multi-well and single-well pads found on page 31. Parcels must have at least one well in order to retain a lease; therefore, the potential minimum wells developed for each of the lease parcels is one. To determine the potential maximum wells developed for each lease parcel, the area of each parcel in acres was divided by the average acres disturbed for each well. If the result was greater than the maximum wells per Township, the potential maximum was set to the maximum wells per Township; otherwise, the result was used.

Table 0-3. Potential Conventional Well Development for the Seven Lease Parcels

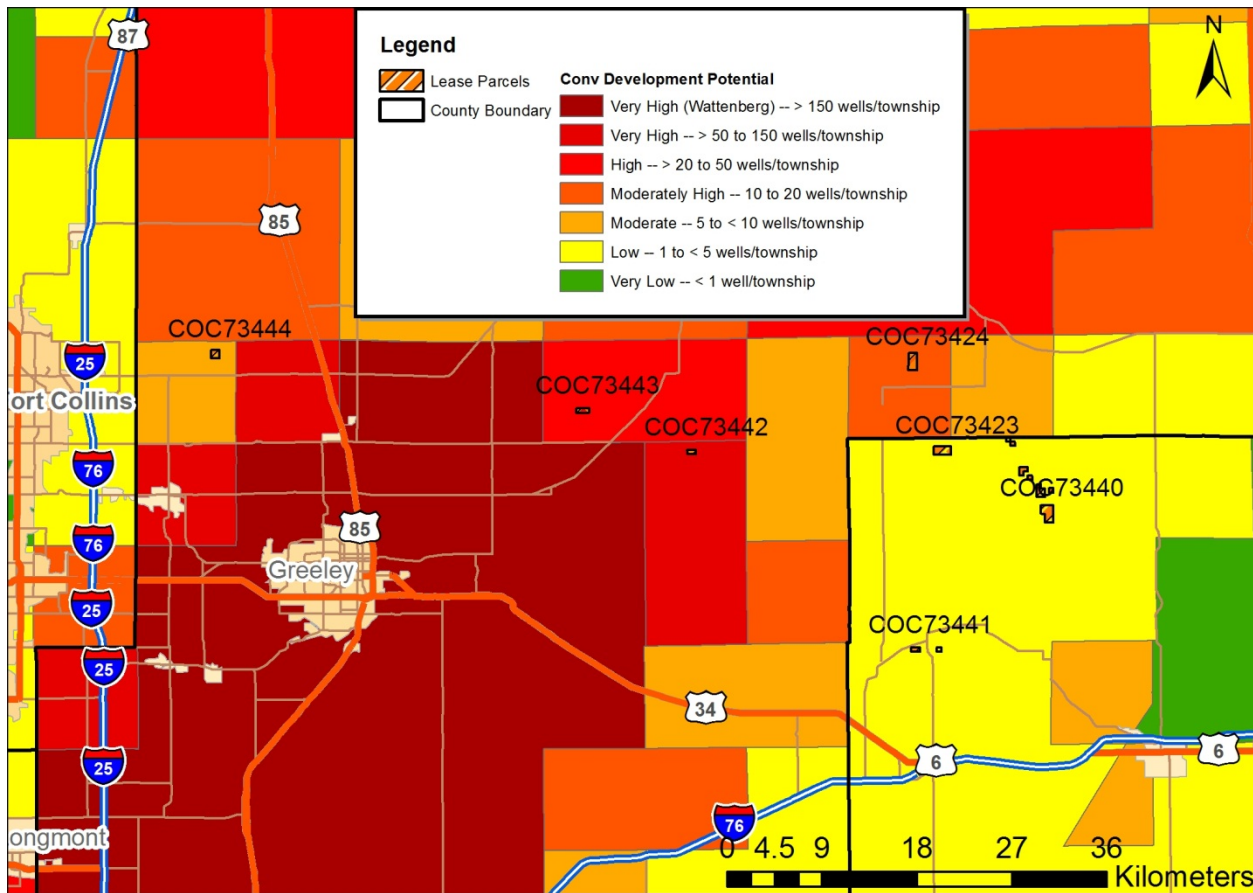
Parcel Serial #	In Non-attainment Area? ¹	Development Category	Minimum Wells per Township	Maximum Wells per Township	Area of Parcel (acres)	Average Acres Disturbed per Well ²	Potential Minimum Wells Developed in Parcel ³	Potential Maximum Wells Developed in Parcel ⁴
COC73444	Y	Moderate	5	9	160	7.6	1	9
COC73443	Y	High	21	50	123	7.6	1	16
COC73442	Y	Very High	51	150	80	7.6	1	10
COC73424	Y	Moderately High	10	20	320	7.6	1	20
COC73423	N	Low	1	4	320	2.1	1	4
COC73441	N	Low	1	4	120	2.1	1	4
COC73440	N	Low	1	4	879	2.1	1	4

(1) Parcels are either within the Greater Wattenberg Non-Attainment Area (NAA) or to the east of the NAA.

(2) Average acres disturbed is determined from values in the RFD.

(3) Parcels must have at least one well to retain lease.

(4) Potential maximum wells developed is either the number of wells that will fit in the parcel, or the maximum per Township, if the former is greater.



Map 0-2. Conventional O&G Development Potential

POTENTIAL OIL AND GAS ACTIVITIES

Potential oil and gas activities on the lease parcels range from land disturbance from construction and drilling, to well completion activities from venting and flaring, and production activities. Particulate emissions could be generated from the construction of new well pads, roads and pipelines. Construction emissions will also include criteria pollutants from exhaust emissions from construction traffic and drilling engines. At times, during completion, well workovers, or blowdowns, gas may be vented or flared.

Potential oil and gas activity levels for the seven lease parcels were estimated from a variety of sources. Potential oil, gas, condensate, and water produced from wells that could be developed on the lease parcels were estimated by the BLM Colorado State Office (BLM-CSO) from Applications for Permit to Drill (APD) submissions from other sites in the area of the seven lease parcels.

Data requests were sent out to oil and gas operators that work in the area of the seven lease parcels. Only one operator sent back a response. This data was used to supplement the data from the APDs.

Another source of data was the Pike and San Isabel National Forests and Cimarron and Comanche National Grasslands (PSICC) Air Quality Study. The data from this study was used to fill in any data gaps left after the APD and operator data had been entered.

PER-WELL EMISSIONS INVENTORY

The per-well emissions were calculated using the activity data listed in the above section along with emission factors taken from AP-42 (USEPA 1998, 2000, 2006), the American Petroleum Institute's Compendium (API 2009), the USEPA's *Protocol for Equipment Leak Emissions Estimates*, as well as, emissions factors developed for the Piceance Basin in western Colorado.

Emissions calculations took into account all current EPA and Colorado regulations on the oil and gas industry. The latest EPA regulations that affect this project include the following (USEPA 2012):

- High-bleed pneumatic controllers must have a gas bleed limit of 6 cubic feet of gas per hour, and
- Storage tanks with VOC emissions of 6 tons per year or more are required to reduce emissions by at least 95%.

The estimated per-well emissions for the seven lease parcels are listed in Table 2-2 below.

Table 0-4. Per-Well Emissions Estimates

Resource/Phase	PM ₁₀ tpy	PM _{2.5} tpy	NO _x tpy	SO ₂ tpy	CO tpy	VOC tpy	HAPs tpy	CO ₂ tpy	CH ₄ tpy	N ₂ O tpy
Oil										
Construction	28.51	3.61	11.16	0.03	2.63	0.75	0.08	1,518.74	0.03	0.01
Operation	15.62	1.64	10.58	0.01	6.26	20.96	2.01	1,149.23	20.86	0.02
Maintenance	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.00
Reclamation	0.06	0.01	0.02	0.00	0.01	0.00	0.00	1.73	0.00	0.00
Total	44.27	5.27	21.75	0.03	8.90	21.72	2.09	2,670.32	20.89	0.03
Natural Gas										
Construction	28.62	3.63	11.18	0.03	2.77	0.76	0.08	1,563.51	0.03	0.01
Operation	14.68	1.65	4.53	0.01	8.06	33.30	3.65	1,211.83	31.69	0.01
Maintenance	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.00
Reclamation	0.06	0.01	0.02	0.00	0.01	0.00	0.00	1.73	0.00	0.00
Total	43.45	5.30	15.73	0.03	10.84	34.06	3.73	2,777.69	31.72	0.03

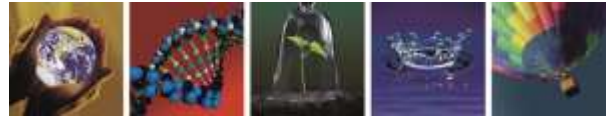
SUMMARY

Per-well emissions estimates have been calculated for seven parcels in Weld and Morgan Counties in Colorado. These estimates were calculated using the most current data available and included the most current rules and regulations. Colorado has published recommended modeling thresholds for new sources of emissions (CDPHE 2011). These thresholds are exceeded by the per-well emissions estimates for short-term and long-term PM₁₀ and PM_{2.5}, and short-term NO_x. Approximately half of the estimated emissions of PM₁₀, PM_{2.5}, NO_x and CO₂ come from construction related activities. These activities are expected to last a few weeks per well. The BLM may also require additional controls as conditions of approvals at the permitting stage, which could further reduce emissions. These additional controls may include, but are not limited to, Tier 4 engines and fugitive dust control for construction and traffic.

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Exhibit 4



**COLORADO AIR RESOURCE
MANAGEMENT MODELING STUDY
(CARMMS)
2021 MODELING RESULTS FOR THE HIGH,
LOW AND MEDIUM OIL AND GAS
DEVELOPMENT SCENARIOS
Final**

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1.0 INTRODUCTION

1.1 Background

The Bureau of Land Management (BLM) is in the process of developing new Resource Management Plans (RMPs) for several Field Offices in Colorado. The draft RMP for the Grand Junction Field Office (GJFO) was released in January 2013¹. In May 2013, a draft RMP for the Dominguez-Escalante National Conservation Area (D-E NCA) was released². The draft RMP for the Uncompahgre Field Office (UFO³), the RMP revision for the Royal Gorge Field Office (RGFO⁴), and the Roan Plateau Planning Area Supplemental Environmental Impact Statement (SEIS⁵) are all in preparation, or pre-planning. As part of these RMPs, BLM is estimating the air quality (AQ) and air quality related value (AQRV) impacts due to the projected BLM-authorized mineral development activities. The analysis includes the cumulative AQ and AQRV impacts due to all Reasonable Foreseeable Development (RFD) sources in the region. In the past, individual RMPs have generally performed their own AQ/AQRV analysis for a long-term year (e.g., 20 years out) when the maximum RMP development is projected to occur. This has resulted in inefficiencies and potential inconsistencies in the RMP's AQ/AQRV analysis and a possibility for a failure to adequately assess the effects of cumulative development across all BLM planning areas on AQ/AQRV in the region. In addition, making emissions projections for such a long-term future year results in increased uncertainties and may create potential inconsistencies in the RMP planned and actual development activities. Thus, the BLM GJFO RMP Air Resource Management Plan (ARMP⁶) contains a commitment to perform a unified regional air quality modeling study to address the AQ/AQRV impacts due to development activities within the GJFO planning area as well as all of BLM Colorado's development activities for a short-term year approximately 10 years in the future.

To address this commitment, the BLM has contracted with Environmental Management Planning and Solutions Inc. (EMPSi), and their Subcontractors ENVIRON International Corporation (ENVIRON) and Carter Lake Consulting (CLC), to perform the Colorado Air Resource Management Modeling Study (CARMMS). The first step in the CARMMS air quality modeling was the development of a Photochemical Grid Model (PGM) and far-field dispersion Modeling Protocol (ENVIRON, Carter Lake and EMPSi, 2014). The Modeling Protocol describes procedures for addressing potential AQ and AQRV impacts due to BLM-authorized mineral development and other BLM-authorized activities in Colorado and in particular within the GJFO and other BLM FOs planning areas in Colorado. AQRVs include visibility, sulfur and nitrogen deposition and lake acid neutralizing capacity (ANC).

The BLM New Mexico State Office (NMSO) is also looking at preparing a RMP for oil and gas development within the Mancos Shale development area in northwestern New Mexico that resides

¹ <http://www.blm.gov/co/st/en/fo/gjfo/rmp/rmp.html>

² http://www.blm.gov/co/st/en/nca/denca/denca_rmp.html

³ http://www.blm.gov/co/st/en/fo/ufo/uncompahgre_rmp.html

⁴

http://www.blm.gov/pgdata/etc/medialib/blm/co/field_offices/royal_gorge_field/oil_and_gas.Par.16932.File.dat/RoyalGorgeFinal_RFD_August_2012%20web.pdf

⁵ http://www.blm.gov/co/st/en/BLM_Programs/land_use_planning/rmp/roan_plateau.html

⁶

http://www.blm.gov/pgdata/etc/medialib/blm/co/field_offices/grand_junction_field/Draft_RMP/appdx.Par.47942.File.dat/AppendixG_Draft%20GJFO%20Air%20Plan_508.pdf

primarily within the BLM New Mexico Farmington Field Office (NMFFO). Given that the Mancos Shale development area is adjacent to some of the Colorado BLM Planning Areas and resides within the CARMMS modeling domain, the BLM decided to add the Mancos Development area to the CARMMS analysis.

The BLM Colorado State Office (COSO) convened an Interagency Air Quality Review Team (IAQRT) that consists of U.S. Environmental Protection Agency (EPA) Region 8, Colorado Department of Health and Environment (CDPHE) Air Pollution Control Division (APCD), National Park Service (NPS), Fish and Wildlife Service (FWS) and United States Forest Service (USFS) to review and comment on the Modeling Protocol in accordance with the June 23, 2011 Memorandum of Understanding (MOU⁷) between the United States Department of Interior (USDOI), United States Department of Agriculture (USDA) and United States Environmental Protection Agency (EPA) on procedures for assessing the AQ and AQRV impacts due to on-land oil and gas development activities on Federal lands under the National Environmental Policy Act (NEPA). With the addition of the NMFFO Mancos Shale development to CARMMS, the IAQRT was expanded to include EPA Region 6 and the New Mexico Environmental Department (NMED).

1.2 Purpose

This document presents the final 2021 modeling results for the CARMMS High, Low and Medium Development Scenarios source apportionment modeling. Presented are the individual AQ and AQRV impacts due to oil and gas (O&G) development on Federal lands within 13 separate Colorado BLM planning areas and the NMFFO Mancos Shale development area as well as the combined assessment of O&G development on Federal and non-Federal lands. In addition, the AQ and AQRV impacts due to mining within the 13 Colorado BLM planning areas and all O&G development within the 4 km CARMMS domain is presented. The 2021 modeling results are compared against National and State Ambient Air Quality Standards (NAAQS and SAAQS) throughout the 4 km modeling domain. The contributions of O&G development to AQ and AQRV at Class I and sensitive Class II areas are presented and compared to PSD increment concentrations and visibility and deposition thresholds of concern.

The CARMMS modeling was performed following procedures documented in a Modeling Protocol. A first draft CARMMS air assessment Modeling Protocol was prepared in August 2013. The BLM and their contractors presented the results of the first draft CARMMS Modeling Protocol to the IAQRT at the BLM COSO office in Denver on October 30, 2013. The IAQRT provided comments on the first draft Modeling Protocol that were incorporated into a draft final Modeling Protocol that was released in January 2014 (ENVIRON, CLC and EMPSi, 2014) along with a Response-to-Comments document that was also dated January 2014. Another meeting with the IAQRT was held at the BLM COSO office on February 28, 2014. IAQRT provided several comments that were addressed in a March 4, 2014 Response-to-Comments document and incorporated into this document. A preliminary draft CARMMS modeling report was prepared in May 2014 that included results for just the 2021 High Development Scenario. Based on comments from BLM, the preliminary draft CARMMS report was updated in an interim draft CARMMS report dated October 2014 that included the 2021 High and Low Development Scenarios modeling results. After

⁷ <http://www.epa.gov/compliance/resources/policies/nepa/air-quality-analyses-mou-2011.pdf>

completion of the 2021 Medium Development Scenario source apportionment modeling this final reported was prepared in December 2014 that includes the 2021 High, Low and Medium Development Scenarios results.

1.3 Overview of Modeling Approach

CARMMS is using a photochemical grid model (PGM) to assess the AQ and AQRV impacts associated with BLM-authorized mineral development on Federal lands within BLM Colorado and the New Mexico Farmington Field Office Planning Areas. CARMMS will not assess the near-source AQ impacts of the O&G and other development activities; that will be addressed at the Project level in the future. The development of a PGM database is quite resources intensive. Thus, to the extent possible, CARMMS has leveraged two studies that have or are developing PGM modeling databases for the western states:

1. The West-wide Jump-start Air Quality Modeling Study (WestJumpAQMS) has performed meteorological, emissions and air quality modeling using a 36 km CONUS, 12 km WESTUS and 4 km Intermountain West modeling domains for the 2008 calendar year. Details on the WestJumpAQMS modeling approach, the PGM 2008 base case modeling and model performance evaluation are available on the WestJumpAQMS website⁸ and contained within the WestJumpAQMS Modeling Protocol (ENVIRON, Alpine and UNC, 2013a⁹) and final report (ENVIRON, Alpine and UNC, 2013b¹⁰).
2. The Three-State Air Quality Study (3SAQS) used the WestJumpAQMS 2008 PGM modeling platform and is developing a new PGM modeling database for the western U.S. and the 2011 calendar year. 3SAQS performed 2020 emissions scenario modeling on the 36/12 CONUS/WESTUS domains using the 2008 modeling platform. 3SAQS is also developing a 2011 modeling platform and performing 2011 and 2020 emission scenario modeling with the 2011 modeling platform. The 3SAQS 2011 modeling platform was not ready in time for the CARMMS modeling.

For CARMMS, WestJumpAQMS developed a stand-alone 2008 4 km CAMx PGM modeling database for the CARMMS 4 km modeling domain shown in Figure 2-1. Boundary Conditions (BCs) for the 4 km CARMMS domain were obtained from a CAMx 2008 36/12 km simulation conducted by WestJumpAQMS. WestJumpAQMS has conducted a model performance evaluation for the WRF 2008 36/12/4 km meteorological simulation and the CAMx 2008 36/12/4 km base case simulation that are summarized for the CARMMS 4 km domain in, respectively, Appendices A and B with more details available on the WestJumpAQMS website¹¹.

The CARMMS CAMx modeling of the CARMMS 4 km modeling domain (Figure 2-1) for a 2021 future year emission scenario using the WestJumpAQMS 2008 meteorological inputs involved the following activities:

⁸ <http://www.wrapair2.org/WestJumpAQMS.aspx>

⁹ http://www.wrapair2.org/pdf/WestJumpAQMS_Modeling_Protocol_and_Source%20Apportionment_Design_FinalMay.pdf

¹⁰ http://www.wrapair2.org/pdf/WestJumpAQMS_FinRpt_Finalv2.pdf

¹¹ <http://www.wrapair2.org/WestJumpAQMS.aspx>

- Develop a 2021 Future Year emissions scenario using the CARMMS estimates of oil and gas and other mineral development within the Colorado and northern New Mexico BLM planning areas and the EPA/3SAQS 2020 emission estimates for all other source categories.
 - For O&G emissions in the western Colorado BLM Planning Areas, CARMMS developed emissions calculators (Appendix C) with data specific to each area. BLM COSO provided 2021 oil and gas activity projections for a High, Low and Medium Development Scenarios.
 - 2021 mining emissions within western Colorado BLM Planning Areas were also estimated using CARMMS emissions calculators (Appendix D).
 - O&G emissions for eastern Colorado BLM Planning Areas were developed in a study for the BLM Royal Gorge Field Office (RGFO) and provided by the BLM COSO.
 - The CARMMS emissions calculators were adapted to estimate emissions for the Mancos Shale development area using information provided by the BLM NMFFO.
 - O&G emissions for the Uinta Basin were developed for the Air Resource Management Study (ARMS) and were provided by the BLM Utah State Office (UTSO).
 - O&G emissions for the Wyoming were based on recent future year emission developed for the BLM Wyoming State Office (WYSO) Continental Divide-Creston Draft EIS¹² modeling.
 - O&G emissions for the remainder of the region were based on recent 2020 emission projections developed by the Three State Air Quality Study (3SAQS)
 - Future year anthropogenic emissions for the remainder of the source categories were based on a 2020 emissions inventory developed by EPA for the PM_{2.5} NAAQS rulemaking and updated by 3SAQS.
 - Future year emissions for biogenic sources, fires, windblown dust, sea salt and lightning were kept constant at 2008 levels and were based on the WestJumpAQMS.
- The future year emissions were processed using the SMOKE emissions model to generate 2020/2021 emissions for the WestJumpAQMS 36/12 km domain and 4 km CARMMS domain.
- CAMx modeling was performed for the 36/12 km domains and the 2020/2021 emissions scenario using the 2008 WestJumpAQMS modeling platform.
- 2020/2021 Boundary Condition (BC) inputs for the CARMMS 4 km modeling domain were generated using output from the 36/12 km CAMx model simulation for the 2020/2021 emissions scenario using the 2008 WestJumpAQMS 2008 meteorological inputs.
- CAMx ozone and particulate matter source apportionment simulations were performed for the 2021 High, Low and Medium Development Scenarios and 4 km CARMMS modeling domain using the 2008 CARMMS modeling platform.

¹² http://www.blm.gov/wy/st/en/info/NEPA/documents/rfo/cd_creston.html

- The CAMx 2021 4 km CARMMS domain source apportionment output for the High, Low and Medium Development Scenarios were post-processed to obtain the separate AQ and AQRV impacts due to mineral development activities on Federal lands within each of the 13 Colorado and the northern New Mexico BLM planning areas.
- The CAMx 2021 High, Low and Medium O&G Development Scenarios output was also post-processed to obtain the cumulative AQ and AQRV impacts due to mineral development on Federal and non-Federal lands within all of the Colorado and the northern New Mexico BLM planning areas as well as O&G development throughout the CARMMS 4 km modeling domain.
- The AQ and AQRV impacts of BLM-authorized oil and gas development on Federal lands within each BLM Colorado planning areas alone and cumulative impacts across all planning areas for the 2021 High, Low and Medium Development Scenarios are summarized in this final report.

1.4 Air Quality Standards and AQRV Thresholds

1.4.1 Federal and State Air Quality Standards and PSD Increments

EPA sets National Ambient Air Quality Standards (NAAQS) for six pollutants, which are called criteria air pollutants (CAPs). The CAPs are: ozone (O₃), nitrogen dioxide (NO₂), carbon monoxide (CO), suspended Particle Pollution (particulate matter with a mean aerodynamic diameter of less than or equal to 10 and 2.5 microns; PM₁₀ and PM_{2.5}), sulfur dioxide (SO₂) and lead (Pb). States may also set their own ambient air quality standards, which must be as stringent as the NAAQS but may be more stringent.

Federal air quality regulations adopted and enforced by the states limit incremental emission increases to specific levels defined by the classification of air quality in an area. The Prevention of Significant Deterioration (PSD) Program is designed to limit the incremental increase of specific air pollutant concentrations above a legally defined baseline level. Incremental increases in PSD Class I areas are strictly limited, while increases allowed in Class II areas are less strict. PSD Class I and Class II increments are defined for NO₂, PM₁₀, PM_{2.5} and SO₂. Please note the PSD increments are project level thresholds, and are not an appropriate metric for reference against field office level impacts.

Table 1-1 summarizes the NAAQS, the Colorado Ambient and Quality Standards (CAAQS) and the New Mexico Ambient Air Quality Standards (NMAAQs). PSD Class I and Class II increments are also shown in Table 1-1.

Table 1-1. Applicable National and State Ambient Air Quality Standards and PSD concentration increments.

Pollutant/Averaging Time	NAAQS	CAAQS ¹³	NMAAQs ¹⁴	PSD Class I Increment ¹	PSD Class II Increment ¹
CO					
1-hour ²	35 ppm	--	13.1 ppm	--	--
8-hour ²	9 ppm	--	8.7ppm	--	--
NO₂					
1-hour ³	100 ppb	--	--	--	--
24-hour	--	--	0.10 ppm	--	--
Annual ⁴	53 ppb	--	0.05 ppm	2.5	25
O₃¹⁵					
8-hour ⁵	0.075 ppm	--	--	--	--
PM₁₀					
24-hour ⁶	150 µg/m ³	--	--	8	30
Annual ⁷	--	--	--	4	17
PM_{2.5}					
24-hour ⁸	35 µg/m ³	--	--	2	9
Annual ⁹	12 µg/m ³	--	--	1	4
SO₂					
1-hour ¹⁰	75 ppb	--	--		
3-hour ¹¹	0.5 ppm	700 µg/m ³	--	25	512
24-hour ¹²	--	--	0.10 ppm	5	91
Annual ⁴	--	--	0.02 ppm	2	20

1. The PSD demonstrations serve information purposes only and do not constitute a regulatory PSD increment consumption analysis.
2. No more than one exceedance per calendar year; for MAAQS - No more than one exceedance per consecutive 12 months
3. 98th percentile, averaged over 3 year; for MAAQS - not to be exceeded more than once over any 12 consecutive months
4. Annual mean not to be exceeded; for MAAQS - arithmetic average over any four consecutive quarters not to be exceeded
5. Fourth-highest daily maximum 8-hour ozone concentrations in a year, averaged over 3 years
6. Not to be exceeded more than once per calendar year on average over 3 years.
7. 3 year average of the arithmetic means over a calendar year
8. 98th percentile, averaged over 3 years
9. Annual mean, averaged over 3 years, NAAQS promulgated December 14, 2012
10. 99th percentile of daily maximum 1-hour concentrations in a year, averaged over 3 years
11. No more than one exceedance per calendar year (secondary NAAQS) and no more than one exceedance in 12 consecutive months (CAAQS)
12. For areas in New Mexico not within 3.5 miles of the Chino Mines Company
13. <http://www.colorado.gov/cs/Satellite/CDPHE-Main/CBON/1251601911433>
14. <http://www.nmcpr.state.nm.us/nmac/parts/title20/20.002.0003.htm>
15. In December 2014 EPA proposed a new primary 8-hour ozone NAAQS that would lower the threshold to somewhere in the 65-70 ppb range that will be promulgated in October 2015.

1.4.2 Air Quality Related Value (AQRV) Thresholds

The impacts of each BLM authorized oil and gas and other activities within each BLM Planning area, as well as cumulative impacts of all activities together, at Class I and sensitive Class II areas will be assessed for three AQRVs: visibility, deposition and acid neutralizing capacity (ANC). The June 23, 2011 MOU between EPA, USDOl and USDA states that the project and cumulative AQRV impacts at Class I and sensitive Class II areas should be assessed by comparing against thresholds of concern defined by the Federal Land Manager (FLM) for the given Class I or sensitive Class II area in question. In the CARMMS first draft Modeling Protocol and at the October 30, 2013 meeting with the Interagency Air Quality Review Team (IAQRT) we presented the following threshold of concern for AQRVs in Class I and sensitive Class II areas and there were no disagreements in the comments received from the IAQRT:

- Visibility impacts for BLM-authorized oil and gas sources within each BLM Planning Area are assessed using the FLAG (2010) procedures that use the new IMPROVE equation, annual average natural visibility background and monthly relative humidity adjustment factors [f(RH)] (see Section 4.6.1). The visibility impacts from mineral development on Federal lands within each separate BLM planning area are compared against a 0.5 and 1.0 change in deciview (dv) haze index threshold of concern and any exceedances will be reported. Please note the dv thresholds are project level thresholds, and not an appropriate metric to reference against field office level or cumulative impacts.
- Cumulative sources visibility impacts from multiple BLM Planning Areas are assessed using a new visibility approach and metrics developed by the FLMs based on the regional haze rule visibility metrics for the best and worst 20% visibility days as discussed in Section 4.6.2.
- Acid deposition impacts due to mineral development on Federal lands within each separate BLM Planning Area for annual total sulfur (S) and total nitrogen (N) deposition are compared against the 0.005 kg/ha/yr Deposition Analysis Threshold (DAT) for the western states. Please note the DAT is a project level threshold, and not an appropriate metric to reference against field office level or cumulative impacts.
- Total N and S deposition impacts due to all emissions in the 2008 and 2021 emissions scenarios (i.e., cumulative) are compared to Critical Load values of 2.2 kg/ha/yr for N in Wyoming, 2.3 kg/ha/yr for N in Colorado except for Dinosaur National Monument where a 3.0 kg/ha/yr Critical Load value for N is used. For S, a 5.0 kg/ha/yr critical load value is used everywhere (see Section 4.7).
- The predicted annual deposition fluxes of sulfur and nitrogen at sensitive lake receptors due to Federal O&G development from individual BLM Planning Areas are used to estimate the change in ANC in accordance with the January 2000, USFS Rocky Mountain Region's Screening Methodology for Calculating ANC Change to High Elevation Lakes, User's Guide (USFS, 2000). The predicted changes in ANC are compared with the USFS's Level of Acceptable Change (LAC) thresholds of 10% for lakes with ANC values greater than 25 µeq/l and 1 µeq/l for lakes with background ANC values of 25 µeq/l and less (see Section 4.8). Please note the LAC is a project level threshold, and not an appropriate metric to reference against field office level or cumulative impacts.

2.0 CARMMS DATABASE DEVELOPMENT

2.1 Modeling System

The CARMMS 2008 modeling database was based on the WestJumpAQMS so the same modeling system was adopted. The justification for the model selection is given in the CARMMS Modeling Protocol (ENVIRON, Cater Lake and EMPSi, 2014). Table 2-1 lists the main models selected for the BLM CARMMS modeling with a brief summary of the reasons for their selection as follows:

- The WRF meteorological model was selected because it contains more recent updates and features compared to the MM5 alternative that is no longer supported by its developer.
- The SMOKE emissions model is the most current and up-to-date emissions modeling system and has performance improvements over the alternatives.
- The MOVES on-road mobile emissions modeling system is the recommended modeling system by the EPA.
- The MEGAN biogenic emissions model has been updated by WRAP specifically for simulating biogenic emissions in the western states.
- The CAMx photochemical grid model (PGM) includes a source apportionment capability that is critically important for the CARMMS and was not available in the version of CMAQ PGM alternative at the time the study was initiated.

Table 2-1. Summary of models selected for the BLM CARMMS modeling.

Model Type	Selected Model
Meteorological Model	Weather Research Forecasting (WRF)
Emissions Model	Sparse Matrix Operator Kernel Emissions (SMOKE)
Emissions Model – On Road Sources	Motor Vehicle Emissions Simulator (MOVES2010)
Emissions Model – Biogenic Sources	Model for Emissions of Gases and Aerosols in Nature (MEGAN)
Photochemical Grid Model	Comprehensive Air-quality Model with extensions (CAMx)

2.2 Episode Selection

Since the CARMMS will need to address annual average air quality issues (e.g., PM_{2.5}) and deposition issues, a full year is selected for modeling. Due to computational requirements and resource constraints, a single meteorological baseline year will be modeled. The entire 2008 calendar year was selected for the CARMMS modeling because it satisfied the most episode selection criteria of recent years:

1. The entire 2008 calendar year includes a variety of meteorological conditions. The year appears to have higher than average photochemical production potential so was not an atypical low year for secondary ozone and PM formation.
2. 2008 had observed ozone and PM_{2.5} concentrations that were close to and even above the ozone and PM_{2.5} Design Values in Colorado.

3. The 2008 year did not include any special study data in Colorado. Note that enhanced monitoring of the Front Range region and vicinity was collected for the summer of 2014, but that was after most of the CARMMS modeling was completed.
4. By modeling a full year (366 days) there should be sufficient number of days to calculate Relative Response Factors (RRFs) following EPA's guidance document (EPA, 2007).
5. The 2008 calendar year was already modeled as part of the Denver ozone modeling and in the WestJumpAQMS and 3SAQS. In particular, the ability to leverage the CARMMS database development off of WestJumpAQMS is critical to the success of the study.
6. Ozone nonattainment areas under the March 2008 0.075 ppm 8-hour ozone NAAQS were designated using 2008-2010 observations, which includes the selected 2008 modeling period.
7. The entire 2008 calendar year dataset includes both weekdays and weekend days.
8. Of the recent years, 2008 fulfills more of the episode selection criteria than other recent years available at the time the project was initiated.

2.3 CARMMS Modeling Domains

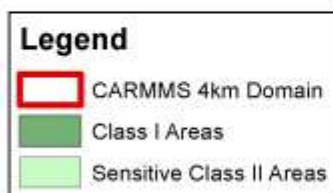
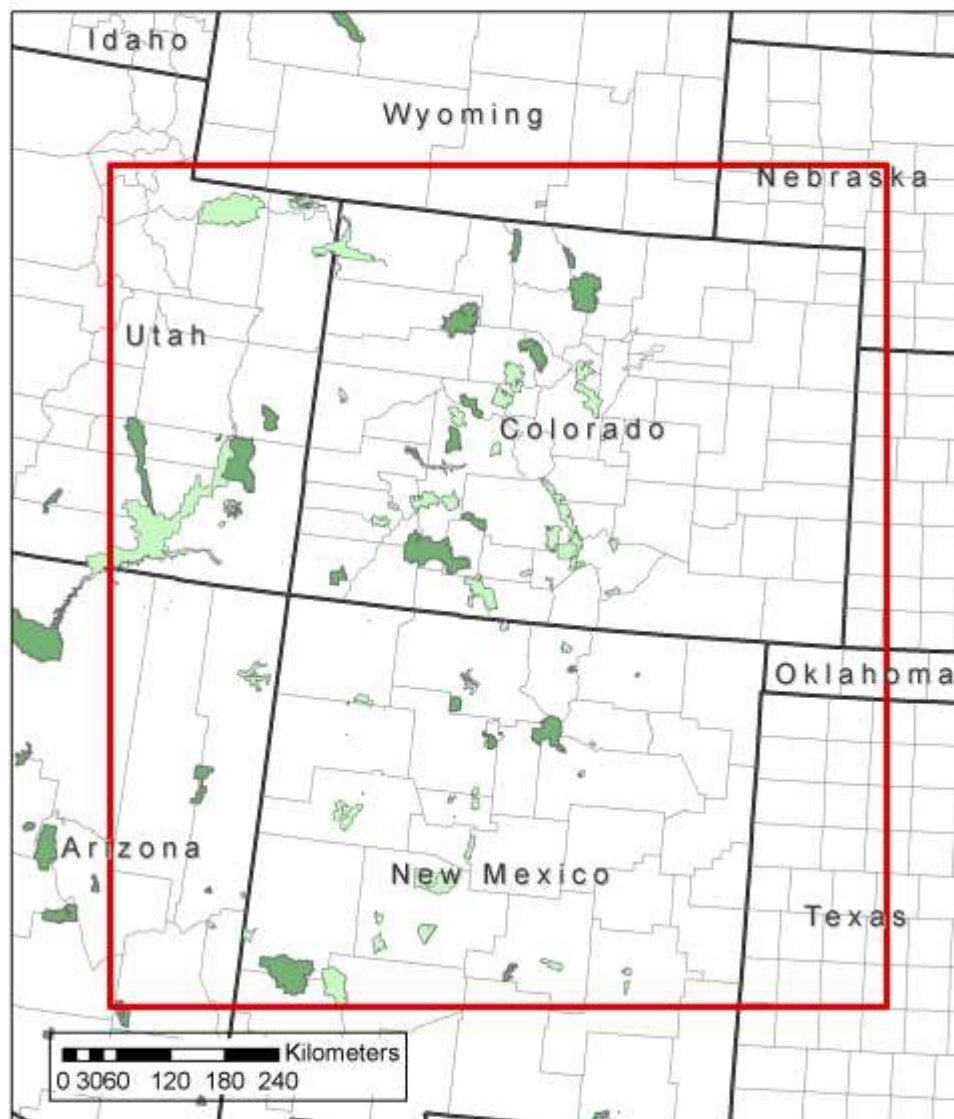
To leverage modeling data from other studies, the CARMMS adopted the so-called RPO Lambert projection that uses a longitude/latitude origin at (-97, 40) and standard latitude parallels of 33 and 45 degrees. Figure 2-1 displays the 4 km modeling domain used in the CARMMS emissions and photochemical modeling. An initial 4 km modeling domain was identified by including all Class I areas for which any part of the Class I area is within 200 km of a western Colorado BLM Field Office Planning Area. While developing the Modeling Protocol, the BLM New Mexico State Office (NMSO) indicated that they would like to include their Mancos Shale Oil development in the CARMMS modeling. The Mancos Shale Oil development area would be within the New Mexico BLM Farmington Field Office area, but would primarily reside in San Juan County with portions potentially stretching into neighboring Rio Arriba, Sandoval and McKinley Counties. Thus, the CARMMS 4 km domain was extended southward to include all Class I areas within 300 km of the Mancos Shale development area.

Figure 2-1 also shows the Class I areas throughout the domain that were analyzed for air quality and AQRV impacts. More details on the Class I and sensitive Class II areas where the AQ and AQRV impacts due to oil and gas and other activities within the BLM planning areas will be assessed is given in Chapter 4.

The CAMx vertical domain definitions will depend on the definition of the WRF vertical layer structure. WRF was run with 37 vertical levels (36 vertical layers using CAMx definition of layer thicknesses) from the surface up to 50 mb (~19-km high above mean sea level) (ENVIRON and Alpine, 2012¹³). The WRF model employs a terrain following coordinate system defined by pressure, using multiple layers that extend from the surface to 50 mb (approximately 19 km

¹³ http://www.wrapair2.org/pdf/WestJumpAQMS_2008_Annual_WRF_Final_Report_February29_2012.pdf

above mean sea level). CARMMS is adopting the same layer collapsing strategy as used by WestJumpAQMS whereby multiple WRF layers are combined into one CAMx layer to reduce the air quality model computational time. Table 2-2 displays the approach for collapsing the WRF 36 vertical layers to 25 vertical layers in CAMx for CARMMS and WestJumpAQMS. The WRF layer collapsing scheme in Table 2-2 is collapsing two WRF layers into one CAMx/CMAQ layer for the lowest four layers in CAMx/CMAQ. In the past, the lowest layers of MM5/WRF were mapped directly into CAMx/CMAQ with no layer collapsing. However, in those applications the MM5/WRF layer 1 was much thicker (20-40 m) than used in this WRF application (12 m). Use of a 12 m lowest layer may trap emissions in a too shallow layer and may result in overstated surface concentrations. For example, NO_x emissions are caused by combustion so are buoyant and have plume rise that in reality could take them out of the first layer if it is defined too shallow.



Coordinates of 4km Domain:

SW Corner: (-1260,-720) km
NE Corner: (-396,216) km
(nx,ny) = (216,234)

Projection = Lambert Conformal
parameters: (-97, 40, 33, 45)

Figure 2-1. 4 km modeling domain used in the Colorado Air Resource Management Modeling Study (CARMMS).

Table 2-2. 37 Vertical layer interface definition for WRF simulations (left most columns), and approach for reducing to 25 vertical layers for CAMx by collapsing multiple WRF layers (right columns).

WRF Meteorological Model					CAMx Air Quality Model		
WRF Layer	Sigma	Pressure (mb)	Height (m)	Thickness (m)	CAMx Layer	Height (m)	Thickness (m)
37	0.0000	50.00	19260	2055	25	19260.0	3904.9
36	0.0270	75.65	17205	1850			
35	0.0600	107.00	15355	1725	24	15355.1	3425.4
34	0.1000	145.00	13630	1701			
33	0.1500	192.50	11930	1389	23	11929.7	2569.6
32	0.2000	240.00	10541	1181			
31	0.2500	287.50	9360	1032	22	9360.1	1952.2
30	0.3000	335.00	8328	920			
29	0.3500	382.50	7408	832	21	7407.9	1591.8
28	0.4000	430.00	6576	760			
27	0.4500	477.50	5816	701	20	5816.1	1352.9
26	0.5000	525.00	5115	652			
25	0.5500	572.50	4463	609	19	4463.3	609.2
24	0.6000	620.00	3854	461	18	3854.1	460.7
23	0.6400	658.00	3393	440	17	3393.4	439.6
22	0.6800	696.00	2954	421	16	2953.7	420.6
21	0.7200	734.00	2533	403	15	2533.1	403.3
20	0.7600	772.00	2130	388	14	2129.7	387.6
19	0.8000	810.00	1742	373	13	1742.2	373.1
18	0.8400	848.00	1369	271	12	1369.1	271.1
17	0.8700	876.50	1098	177	11	1098.0	176.8
16	0.8900	895.50	921	174	10	921.2	173.8
15	0.9100	914.50	747	171	9	747.5	170.9
14	0.9300	933.50	577	84	8	576.6	168.1
13	0.9400	943.00	492	84			
12	0.9500	952.50	409	83	7	408.6	83.0
11	0.9600	962.00	326	82	6	325.6	82.4
10	0.9700	971.50	243	82	5	243.2	81.7
9	0.9800	981.00	162	41	4	161.5	64.9
8	0.9850	985.75	121	24			
7	0.9880	988.60	97	24	3	96.6	40.4
6	0.9910	991.45	72	16			
5	0.9930	993.35	56	16	2	56.2	32.2
4	0.9950	995.25	40	16			
3	0.9970	997.15	24	12	1	24.1	24.1
2	0.9985	998.58	12	12			
1	1.0000	1000	0			0	

2.4 Meteorological Modeling Approach

The CARMMS meteorological inputs for the CAMx modeling are based on the WRF modeling performed as part of the WestJumpAQMS. The WRF computational domains were defined to be slightly larger than the CAMx and SMOKE modeling domains to eliminate the occurrence of boundary artifacts in the CAMx meteorological inputs. Such boundary artifacts can occur when the boundary conditions (BCs) for the meteorological variables come into dynamic balance with WRF's atmospheric equations and numerical methods.

The WRF model contains many different physics options, and achieving the best model performance for any particular year and region is accomplished by performing model sensitivity tests using different options. As part of the post-2008 Denver ozone SIP modeling, Alpine Geophysics, LLC and ENVIRON conducted numerous WRF meteorological sensitivity simulations to determine the best performing configuration for simulating meteorology in the Inter-Mountain West region (Morris et al., 2011). The final WRF configuration was used for the 2008 Denver ozone modeling as well as for the WestJumpAQMS WRF modeling results that are used in CARMMS.

2.4.1 2008 WRF Modeling Methodology

The WestJumpAQMS 2008 WRF modeling methodology is described below. More details are provided in the WestJumpAQMS WRF Application/Evaluation report (ENVIRON and Alpine, 2012¹⁴).

Horizontal Domain Definition: The computational domain on which WRF was applied for WestJumpAQMS included a 36 km CONUS, 12 km WESTUS and 4 km Inter-Mountain West Domain (IMWD). The 4 km domain includes the 4 km CARMMS domain shown in Figure 2-1. The grid projection is Lambert Conformal with a pole of projection of 40 degrees North, -97 degrees East and standard parallels of 33 and 45 degrees, the so-called RPO projection. The datum (size and shape of earth) is a perfect sphere with radius 6370.0 km.

Vertical Domain Definition: The WRF modeling was based on 37 vertical layers with an approximately 12 meter deep surface layer. The vertical domain is presented in both sigma and height coordinates in Table 2-2.

Topographic Inputs: Topographic information for WRF were developed using the standard WRF terrain databases. The 36 km domain is based on the 10 minute (18 km) global data. The 12 km domain is based on the 2 minute (~4 km) data. The 4 km domain is based on 30 second (~900 m) data.

Vegetation Type and Land Use Inputs: Vegetation type and land use information were developed using the most recently released WRF databases provided with the WRF distribution. Standard WRF surface characteristics corresponding to each land use category were employed.

Atmospheric Data Inputs: The first guess fields were taken from the 12 km North American Model (NAM) database.

¹⁴ http://www.wrapair2.org/pdf/WestJumpAQMS_2008_Annual_WRF_Final_Report_February29_2012.pdf

Diffusion Options: Horizontal Smagorinsky first-order closure ($km_opt = 4$) with sixth-order numerical diffusion and suppressed up-gradient diffusion ($diff_6th_opt = 2$) were used.

Lateral Boundary Conditions: Lateral boundary conditions were specified from the initialization dataset (12 km NAM) on the 36 km domain with continuous updates nested from the 36 km domain to the 12 km domain and continuous updates nested from the 12 km domain to the 4 km domain, using one-way nesting ($feedback = 0$).

Top and Bottom Boundary Conditions: The top boundary condition was selected as an implicit Rayleigh dampening for the vertical velocity. Consistent with the model application for non-idealized cases, the bottom boundary condition was selected as physical, not free-slip.

Water Temperature Inputs: The water temperature data were taken from the National Centers for Environmental Prediction (NCEP) Real Time Global (RTG) global one-twelfth degree analysis¹⁵.

FDDA Data Assimilation: The WRF model was run with a combination of analysis and observation nudging (i.e., Four Dimensional Data assimilation [FDDA]). Analysis nudging was used on the 36 km and 12 km domain using the 12 km NAM dataset. For winds and temperature, analysis nudging coefficients of 5×10^{-4} and 3.0×10^{-4} were used on the 36 km and 12 km domains, respectively. For mixing ratio, an analysis nudging coefficient of 1.0×10^{-5} was used for both the 36 km and 12 km domains. The nudging uses both surface and aloft nudging with nudging for temperature and mixing ratio not performed in the lower atmosphere (i.e., within the boundary layer and at the surface). Observation nudging was performed on the 4 km grid domain using the Meteorological Assimilation Data Ingest System (MADIS)¹⁶ observation archive. The MADIS archive includes the National Climatic Data Center (NCDC)¹⁷ observations and the National Data Buoy Center (NDBC) Coastal-Marine Automated Network C-MAN¹⁸ stations. The observational nudging coefficients for winds, temperatures and mixing ratios were 1.0×10^{-4} , 1.0×10^{-4} , and 1.0×10^{-5} , respectively and the radius of influence was set to 50 km.

Physics Options: The WRF model contains many different physics options. The physics options chosen for the WestJumpAQMS application are presented in Table 2-3.

Application Methodology: The WRF model was executed in 5½ day blocks initialized at 12Z every 5 days. Model results were output every 60 minutes. The first twelve (12) hours of each 5 ½ day block is used for model spin-up and not used in the PGM model inputs or in the WRF model performance evaluation. WRF was configured to run in distributed memory parallel mode.

¹⁵ Real-time, global, sea surface temperature (RTG-SST) analysis. <http://polar.ncep.noaa.gov/sst/oper/Welcome.html>

¹⁶ Meteorological Assimilation Data Ingest System. <http://madis.noaa.gov/>

¹⁷ National Climatic Data Center. <http://lwf.ncdc.noaa.gov/oa/ncdc.html>

¹⁸ National Data Buoy Center. <http://www.ndbc.noaa.gov/cman.php>

Table 2-3. Physics options used in the WestJumpAQMS WRF 2008 simulation modeling.

WRF Treatment	Option Selected	Notes
Microphysics	Thompson scheme	New with WRF 3.1.
Longwave Radiation	RRTMG	Rapid Radiative Transfer Model for GCMs includes random cloud overlap and improved efficiency over RRTM.
Shortwave Radiation	RRTMG	Same as above, but for shortwave radiation.
Land Surface Model (LSM)	NOAH	Two-layer scheme with vegetation and sub-grid tiling.
Planetary Boundary Layer (PBL) scheme	YSU	Yonsie University (Korea) Asymmetric Convective Model with non-local upward mixing and local downward mixing.
Cumulus parameterization	Kain-Fritsch in the 36 km and 12 km domains. None in the 4 km domain.	4 km can explicitly simulate cumulus convection so parameterization not needed.
Analysis nudging	Nudging applied to winds, temperature and moisture in the 36 km and 12 km domains	Temperature and moisture nudged above PBL only.
Observation Nudging	Nudging applied to surface wind only in the 4 km domain	Surface temperature and moisture observation nudging can introduce instabilities.
Initialization Dataset	12 km North American Model (NAM)	Also used in analysis nudging

2.4.2 Meteorological Model Performance Evaluation

The WestJumpAQMS performed a comprehensive and detailed model performance evaluation of the 2008 WRF 36/12/4 km model simulation. The WestJumpAQMS WRF model performance evaluation is documented in a WRF Application/Evaluation report that is available on its website (ENVIRON and Alpine, 2012¹⁹). The WRF evaluation consisted of the following:

- Evaluation against surface meteorological observations of wind direction, wind speed, temperature and water vapor mixing ratio (humidity) with monthly performance statistics calculated using the METSTAT program:
 - Surface meteorological performance statistics were calculated across the 36 km CONUS, 12 km WESTUS and 4 km Inter-Mountain West domains, across each individual western state and at individual monitoring sites within each western state, including Colorado²⁰ that is the main focus of the CARMMS.
 - The surface meteorological model performance statistics were compared against model performance evaluation benchmarks in order to help interpret the WRF model performance and compare it with other studies that were used to develop the benchmarks. The 2008 WRF model performance was compared against both the

¹⁹ http://www.wrapair2.org/pdf/WestJumpAQMS_2008_Annual_WRF_Final_Report_February29_2012.pdf

²⁰ <http://www.wrapair2.org/pdf/westjump.wrf.site.co.2012-04-04.pdf>

simple (simple terrain and/or simple meteorological conditions) and complex (complex terrain and/or more complex meteorological conditions) model performance benchmarks.

- The WRF 2008 precipitation estimates were compared with monthly analysis fields generated by the Climate Prediction Center (CPC) in a qualitative evaluation.

Appendix A summarizes some of the WestJumpAQMS WRF model performance evaluation products as they relate to WRF performance within the CARMMS 4 km modeling domain. The WestJumpAQMS 2008 WRF model performance within the CARMMS region is as good or better than meteorological model performance seen in past photochemical modeling studies of the region (e.g., WRAP regional haze modeling and Denver 2008 ozone State Implementation Plan modeling). Thus, the WestJumpAQMS 2008 WRF meteorological fields were judged to be appropriate for use in the CARMMS.

2.5 2008 BASE CASE EMISSIONS

The 2008 Base Case emissions were developed by the WestJumpAQMS. The primary source for the 2008 Base Case emissions is Version 2.0 of the National Emissions Inventory (NEIv2.0²¹). For most source categories, the SMOKE emissions modeling system was used to process the emissions into the hourly gridded speciated emissions needed as input for CAMx. The comprehensive and detailed documentation for the WestJumpAQMS 2008 Base Case emissions inventory is available on the WestJumpAQMS website²² and includes a final report (ENVIRON, Alpine and UNC, 2013) and 16 Emissions Technical Memorandums that provide details on the 2008 emissions for each source category as well as for the parameters used in the emissions modeling.

2.5.1 Source of 2008 Base Case Emissions

Table 2-4 summarizes the emission models and sources of 2008 Base Case emissions that are based primarily on the 2008 NEIv2.0 with the following enhancements:

- Major (≥ 25 MW) Electrical Generating Units (EGUs) point source SO_2 and NO_x emissions used Continuous Emissions Monitor (CEM) measurement data that are available online from the EPA Clean Air Markets Division (CAMD²³). These data are hour-specific for SO_2 , NO_x and heat input. The temporal variability of other pollutant emissions (e.g., PM) for the CEM sources were estimated using the hourly CEM heat input data to allocate the annual emissions from the NEIv2.0 to each hour of the year. Emissions, locations and stack parameters for point sources without CEM devices were based on the 2008 NEIv2.0.
- The WRAP-IPAMS Phase III 2006 oil and gas emission inventories were projected to 2008 for all Phase III basins that were available at the time of the WestJumpAQMS 2008 emissions development. In addition, under WestJumpAQMS new oil and gas emissions

²¹ <http://www.epa.gov/ttnchie1/net/2008inventory.html>

²² <http://www.wrapair2.org/WestJumpAQMS.aspx>

²³ <http://www.epa.gov/airmarkets/>

inventory was developed for the Permian Basin in southeastern New Mexico/northwestern Texas.

- On-road mobile source emissions were based on the MOVES2010²⁴ model with county-specific weekday and weekend day VMT and monthly meteorology for the 2008 base case modeling year.
- The WRAP windblown dust (WBD) model²⁵ was used to generate WBD emissions using day-specific hourly meteorology from the 2008 WRF simulation.
- Sea salt and lightning emissions were generated using the 2008 WRF model hourly gridded output.
- Emissions from fires (wildfires, prescribed burns and agricultural burning) are based on the 2008 fire emissions inventory developed in the Joint Fire Sciences Program (JFSP) Deterministic and Empirical Assessment of Smoke's Contribution to Ozone (DEASCO3²⁶) study.
- Biogenic emissions were generated using an enhanced version of the Model of Emissions of Gases and Aerosols in Nature (MEGAN²⁷) that was updated by WRAP to better represent biogenic emissions for the western states.
- Mexico emissions were based on the 2008 projections from the 1999 Mexico national emissions inventory.
- The Environment Canada 2006 emissions inventory based on the National Pollutant Release Inventory (NPRI) was used for Canada.
- New spatial surrogates for the emissions were developed using the latest 2010 Census and other data that are now available and includes population and housing statistics for 2010. Details on the new spatial surrogates used for allocating county-level emissions to the 4 km grid cells can be found in the WestJumpAQMS Emissions Technical Memorandum Number 13²⁸.

²⁴ <http://www.epa.gov/otaq/models/moves/>

²⁵ <http://www.wrapair.org/forums/dejf/fderosion.html>

²⁶ https://www.firescience.gov/projects/11-1-6-6/proposal/11-1-6-6_11-1-6_attachment_1_primary.pdf

²⁷ <http://acd.ucar.edu/~guenther/MEGAN/MEGAN.htm>

²⁸ http://www.wrapair2.org/pdf/Memo13_Parameters_Sep30_2013.pdf

Table 2-4. Summary of sources of emissions and emission models used to generate 2008 base case emissions for use in CARMMS.

Emissions Component	Configuration	Details
Model Code	SMOKE Version 3.1	http://www.smoke-model.org/index.cfm
Oil and Gas Emissions	Update WRAP Phase III 2006 to 2008	Seven WRAP Phase III Basins in CO, NM, UT and WY plus add 2008 Permian Basin O&G Emissions
Area Source Emissions	2008 NEI Version 2.0	Western state updates, then SMOKE processing of http://www.epa.gov/ttn/chief/net/2008inventory.html
On-Road Mobile Sources	MOVES2010	County specific emissions run for monthly weekday and weekend days. California based on EMFAC2011.
Point Sources	2008 CEM and Non-CEM Sources	Use 2008 day-specific hourly measured CEM for SO ₂ and NO _x emissions for CEM sources, 2008 NEIv2.0 for other pollutants and non-CEM sources
Off-Road Mobile Sources	2008 NEIv2.0	Based on EPA NONROAD model http://www.epa.gov/oms/nonrdmdl.htm
Wind Blown Dust Emissions	WRAP Wind Blown Dust (WBD)	WRAP WBD Model with 2008 WRF meteorology adjusted to be consistent with 2002 WBD modeling
Ammonia Emissions	NEIv2.0	Based on CMU Ammonia Model. Review and update spatial allocation if appropriate.
Biogenic Sources	MEGAN	Enhanced version of MEGAN Version 2.1 from WRAP Biogenics study http://www.wrapair2.org/pdf/WGA_BiogEmissInv_FinalReport_March20_2012.pdf
Fires	2008 DEASCO3	2008 DEASCO3 fire inventory used. http://www.wrapair2.org/pdf/JSFP_DEASCO3_TechnicalProposal_November19_2010.pdf
Temporal Adjustments	Seasonal, day, hour	Based on latest collected information
Chemical Speciation	CB05 Chemical Speciation	CB6 considered but was too new at time study was initiated.
Gridding	Spatial Surrogates based on landuse	Develop new spatial surrogates using 2010 census data and other data
Quality Assurance	SMOKE QA Tools; PAVE, VERDI plots; Summary reports	Follow WRAP emissions QA/QC plan.

2.5.2 On-Road Mobile Sources

The Motor Vehicle Emissions Simulator (MOVES²⁹) is EPA's current tool to construct on-road mobile source emissions estimates for national, state, and county level inventories of criteria air pollutants, greenhouse gas emissions, and some mobile source air toxics from highway vehicles. In addition, MOVES can make projections for energy consumption (total, petroleum-based, and fossil-based). EPA requires that all new regulatory modeling studies use the MOVES model for mobile source emissions and MOVES is also recommended for NEPA studies (EPA, 2012c).

The CARMMS/WestJumpAQMS 2008 on-road mobile source emission modeling was conducted using MOVES2010 (EPA, 2012a). On July 31, 2014, EPA released a new version of MOVES (MOVES2014; EPA, 2014a,b). The CARMMS mobile source emissions modeling was conducted in 2013 using MOVES2010, well before the release of MOVES2014. As stated in EPA's MOVES2014 Policy Guidance (EPA, 2014c) "All states other than California should use MOVES2014 for future SIPs in order to take full advantage of the improvements incorporated in this version. However, state and local agencies that have already completed significant work on a SIP with MOVES2010 can continue to use it"³⁰ (EPA, 2014c).

The WestJumpAQMS ran MOVES2010 configured to estimate 2008 mobile source emissions directly (i.e., emissions inventory mode) at a county level basis by month using the monthly average diurnally varying 2008 WRF meteorological conditions. However, the 3SAQS updated the 2008 and 2020 mobile source emissions using MOVES2010 in the emissions factor mode to generate a lookup table of emissions factors that was used with SMOKE-MOVES and the 2008 WRF gridded hourly meteorological data to generate day-specific hourly gridded on-road mobile source emission inputs. The CARMMS 2021 High, Low and Medium Development Scenarios CAMx source apportionment modeling used the 3SAQS 2020 SMOKE-MOVES on-road mobile source emissions. SMOKE-MOVES spatially allocated the mobile source activity data to the 36/12/4 km modeling domains using spatial surrogates developed using the 2010 census and other data. This includes new spatial surrogate categories specific to new source categories in MOVES (e.g., heavy duty truck idling at rest stops. SMOKE-MOVES also chemically speciated the emissions to the CB05 chemical mechanism using CB05 chemical speciation profiles based on the SPECIATE4.3 database. More details on the 2008 on-road mobile source emissions can be found in the 3SAQS 2008 base case modeling report (Adelman, Shanker, Yang and Morris, 2014).

2.5.3 Area and Non-Road Mobile Sources

The 2008 NEIv2.0 area and non-road emissions were processed using the SMOKE emissions model with new 2010 census spatial surrogates and default temporal and CB05 speciation adjustments. Several source categories within the area and non-road category were removed from the NEIv2.0 so that they could be replaced or updated and separately processed, which allows a more thorough QA/QC analysis. The source categories that were extracted from the NEIv2.0 area and non-road sources for separate treatment or replacement were as follows:

²⁹ <http://www.epa.gov/otaq/models/moves/>

³⁰ <http://www.epa.gov/otaq/models/moves/documents/420b14008.pdf>

- Oil and gas (O&G) exploration and production sources for locations covered by most of the WRAP Phase III O&G Basins and the Permian Basin were removed from the 2008 NEIv2. They were replaced by the WRAP Phase III 2006 emissions projected to 2008 (see Section 2.5.4). New 2008 O&G emissions were developed for the Permian Basin in southeastern New Mexico/northwestern Texas. The 2008 NEIv2.0 O&G emissions were used for the remainder of the U.S. locations, which includes the Williston and Great Plains Basins (North Dakota and Montana) whose WRAP Phase III emissions were not available at the time of the 2008 emissions inventory development.
- Ammonia emissions due to livestock and fertilizer sources were removed from the NEIv2.0 and processed separately.
- Aircraft, locomotive and marine (ALM) sources were processed separately as their own source group in the emissions modeling. The marine sources do not include large ocean going (Class 3) vessels (Commercial Marine Vessels, CMV) that were processed under the off-shore shipping category.
- Fire emissions were removed from the NEIv2.0 and were replaced by 2008 fire emissions developed as part of the DEASCO3 study.
- Fugitive dust emissions were removed from the NEIv2.0 for separate processing.

Below we summarize the processing area and non-road emissions used from the 2008 NEIv2 in the CARMMS 2008 base case, more details can be found in WestJumpAQMS Technical Memorandum No.2 Area and Non-Road Emissions (Loomis, Morris and Adelman, 2013³¹).

2.5.3.1 Area Sources

The NEI Area (or Non-Point) data category contains emission estimates for sources which individually are too small in magnitude or too numerous to inventory as individual point sources, and which can often be estimated more accurately as a single aggregate source for a County or Tribal area. Area source (non-point) emissions are emissions sources that are summed over a geographic region, rather than specifically located. Examples of area sources include small industrial, residential, consumer product, and agricultural emissions. For emissions modeling purposes, these types of emissions are defined by state and county (or tribal) identifiers, and SCC codes. After extracting the area source categories from the NEIv2.0 as indicated above, the remaining area sources in the NEIv2.0 were processed by SMOKE as their own source category.

2.5.3.2 Non-Road Sources

The NEI Non-Road data categories contain mobile sources which are estimated for version 2.0 of the 2008 NEI using the EPA NONROAD³² model, run within the National Mobile Inventory Model (NMIM³³). The non-road emissions have been compiled as both annual total emissions, and average day emissions by month. In order to take the best advantage of the monthly and seasonal variability of the non-road emissions sources, we used the monthly options for SMOKE modeling inputs.

³¹ http://www.wrapair2.org/pdf/Memo_2_Area_Jan22_2013%20review%20draft.pdf

³² <http://www.epa.gov/otaq/nonrdmdl.htm>

³³ <http://www.epa.gov/otaq/nmim.htm>

Note that emissions data for aircraft, locomotives, and commercial marine vessels are not included in the NEI non-road data category starting with the 2008 NEI. These three non-road mobile source categories were handled as special cases, with separate input processing streams. Aircraft engine emissions occurring during Landing and Takeoff Operations (LTO) and the Ground Support Equipment (GSE) and Auxiliary Power Units (APU) associated with the aircraft are now included in the point data category at individual airports in the 2008 NEI. Emissions from locomotives that occur at rail yards are also included in the point data category. In-flight aircraft emissions, locomotive emissions outside of the rail yards, and commercial marine vessel emissions (both underway and port emissions) are included in the Non-Point data category.

2.5.4 2008 Oil and Gas Emissions

For Basins covered by the WRAP-IPAMS Phase III 2006 oil and gas (O&G) emissions available at the time of the 2008 base case emissions development, the WRAP Phase III O&G 2006 emissions were projected to 2008. WestJumpAQMS also developed new 2008 O&G emissions for the Permian Basin in southeastern New Mexico/northwestern Texas. For all other Basins in the U.S. (including Williston and Great Plains Basins whose WRAP Phase III emissions were not available at the time of the 2008 base case development) the 2008 O&G emissions from the NEIv2.0 were used and processed as area and point sources.

2.5.4.1 2008 Phase III O&G Emissions Update

The WRAP Phase III 2006 baseline O&G inventories were projected to 2008 for the following eight WRAP Phase III Basins:

- Denver-Julesburg Basin (CO)
- Piceance Basin (CO)
- Uinta Basin (UT)
- North San Juan Basin (CO)
- South San Juan Basin (NM)
- Wind River Basin (WY)
- Powder River Basin (WY)
- Greater Green River Basin (WY)

The 2008 O&G emission update for the WRAP Phase III and Permian Basins used 2008 O&G production statistics from the Enerdeq database published by IHS Global, also referred to as the “PI Dwight’s” database. This database contains production statistics that are consistent and typically of higher quality than the primary data in individual state O&G Commission databases.

Processing of the IHS data for the 2008 projections followed the same methodology as used in the WRAP Phase III study³⁴. Summaries of production statistics were extracted from the IHS database, including well count by well type and location, spud count, production of gas by well type and well location, production of liquid petroleum (oil or condensate) by well type and well

³⁴ <http://www.wrapair2.org/PhaseIII.aspx>

location, and production of water by well type and well location. All data were summarized at the county and basin level, for tribal and non-tribal land separately as applicable to each basin. No new survey work was conducted for the 2008 O&G emissions update so the analysis did not include any updates of company-specific production statistics as was done in the development of the Phase III 2006 O&G emission inventories. The resulting production statistics data were summarized at the county, tribal and basin levels for all basins including the Permian Basin.

The 2008 production statistics from the IHS database were used to project the Phase III baseline 2006 O&G inventories. The projections will be developed as scaling factors that represented the ratio of the value of a specific activity parameter in 2008 to the value in 2006. The scaling factors were developed at the county and tribal levels for all basins. Scaling factors were then matched to all source categories considered as part of the Phase III inventories, using the same cross-referencing analysis conducted as part of the midterm (2012) projections in the Phase III study. The 2008 to 2006 scaling factors were used to adjust the activity data for the oil and gas emissions.

Where specific scaling factors are estimated to be less than one (1), indicating a reduction in an activity parameter from 2006 to 2008, all emissions factors and activity data will be assumed to be identical in 2008 as in 2006 and the 2006 emissions will be reduced and no emission controls assessment is needed (i.e., when activity is reduced between 2006 and 2008 we are assuming that the same equipment is being used in the field, it is just producing less). In this case, the 2008 emissions will be developed assuming the direct application of the scaling factor with no additional controls.

Where scaling factors are estimated to be greater than one (1), it is assumed that some growth in activity has occurred in the 2006-2008 time period and that new equipment may have been deployed in the field. A controls analysis was conducted specific to each basin and utilizing the control measures identified as part of the WRAP Phase III midterm O&G projections work. The controls analysis only considered broad control factors, rather than detailed analyses as conducted in the Phase III midterm projections. Where no significant impact of controls from federal or state regulations are anticipated in the 2006-2008 time period, no control factors for the specific source category will be assumed.

For Colorado Basins, the permitted O&G 2008 emissions were based on the CDPHE 2008 APEN database rather than projected from the WRAP Phase III 2006 O&G emissions, whose permitted O&G emissions were based on the CDPHE 2006 APEN database. In addition, the Colorado Department of Health and Development (CDPHE) has determined that not all condensate flash VOC emissions that were assumed to be controlled 95% by flares make it to the flare and are instead vented to the atmosphere. Thus, CDPHE has introduced the concept of a Capture Efficiency (CE) for condensate flare control that assumes only 75% of the condensate flash VOC emissions are actually controlled by the flare and the other 25% is released directly to the atmosphere. The CDPHE 75% CE assumption was adopted in the CARMMS/WestJumpAQMS 2008 base case O&G emissions in Colorado. The WRAP Phase III 2006 unpermitted condensate tank O&G emissions are either projected to 2008 (D-J Basin) or the 2008 APEN condensate tank emissions are reduced (Piceance Basin) in order for the total 2008 condensate production in the inventory to match the 2008 IHS database production statistics.

Details on the development of the 2008 O&G emissions for the Colorado Basins, the Uinta and South San Juan Basins and the Wyoming Basins can be found in three WestJumpAQMS Technical Memorandums by, respectively, Bar-Ilan and Morris (2012a³⁵), Bar-Ilan and Morris (2012b³⁶) and Bar-Ilan and Morris (2012c³⁷).

2.5.4.2 2008 Emission Inventory for the Permian Basin

A study prepared by Applied EnviroSolutions, Inc. (AES) on 2007 O&G emissions in the New Mexico portion of the Permian Basin along with 2008 O&G emissions from the Texas Commission on Environmental Quality (TCEQ) was used to develop a comprehensive O&G emissions inventory of the Permian Basin. The Permian Basin lies outside of the CARMMS modeling domain, although Permian Basin emissions are used in the CAMx 36/12 km modeling to provide BCs for the CARMMS 4 km domain. Details on the development of the 2008 O&G emissions for the Permian Basin can be found in WestJumpAQMS Emissions Technical Memorandum Number 4d (Bar-Ilan and Morris, 2013³⁸).

2.5.4.3 2008 O&G Emissions for the Remainder of the U.S.

The WRAP Phase III Basins and Permian Basin O&G emissions described above covers most of an area including northwestern TX, NM, CO, UT and WY and all of the 4 km CARMMS domain. For areas within these states not covered by the WRAP Phase III and Permian Basins, and O&G emissions outside of this region, the O&G emissions from the 2008 NElv2.0 were used. Details on the O&G emissions used in the 2008 base case not covered by the WRAP Phase III Basins can be found in WestJumpAQMS Technical Memorandum No. 4e (Loomis, Adelman, Morris and Bar-Ilan, 2013³⁹).

2.5.5 Fire Emissions

2008 emissions from wild fires, prescribed burns and agricultural burning were based on the comprehensive 2008 fire emissions inventory developed as part of the DEASCO3⁴⁰ project sponsored by the Joint Fire Science Program (JFSP). The WestJumpAQMS emissions Technical Memorandum Number 5 (Morris, Tai, Loomis and Adelman, 2012⁴¹) discusses and compares available fire emissions data for 2008. Details on the DEASCO3 fire emissions development methodology⁴² and the methodology for fire plume rise and speciation⁴³ is available on the DEASCO3 website.

2.5.6 Ammonia Emissions

Ammonia emissions were based on the 2008 NElv2.0 emissions inventory. A vast majority of the ammonia emissions in the 2008 NElv2.0 were from livestock and fertilizer application that

³⁵ http://www.wrapair2.org/pdf/Memo_4a_OG_Jun06_2012_Final.pdf

³⁶ http://www.wrapair2.org/pdf/Memo_4b_OG_June06_2012_Final.pdf

³⁷ http://www.wrapair2.org/pdf/Memo_4c_OG_Jan23_2013_RevisedFinal.pdf

³⁸ http://www.wrapair2.org/pdf/Memo_4d_OG_Apr24_2013_Final.pdf

³⁹ http://www.wrapair2.org/pdf/Final_Memo_4e_RemainderOG_Mar6_2013.pdf

⁴⁰ http://www.wrapair2.org/pdf/JFSP_DEASCO3_TechnicalProposal_November19_2010.pdf

⁴¹ http://www.wrapair2.org/pdf/Memo_5_Fires_Apr27_2012_Final.pdf

⁴² https://wraptools.org/pdf/ei_methodology_20130930.pdf

⁴³ https://wraptools.org/pdf/DEASCO3_Plume_Rise_Memo_20131210.pdf

were based on the CMU ammonia model⁴⁴. Updated spatial surrogates for locations of Concentrated Animal Feeding Operations (CAFOs) in Colorado developed as part of the NPS ROMANS study were used to spatially allocate the NEIv2.0 livestock ammonia emissions in Colorado, which greatly improves the ammonia emissions within the CARMMS domain. Details on the development of the ammonia emissions used in the CARMMS 2008 base case can be found in the WestJumpAQMS Technical Memorandum No. 8 (Loomis, Wilkinson, Adelman and Morris, 2013⁴⁵).

2.5.7 Ocean Going Vessels

The 2008 off-shore shipping emissions inventory was based on the 2008 NEIv2.0. These emissions are developed and carried as point sources, rather than the area-level files generally used for off-road mobile sources, including marine emissions sources. Details on the Off-Shore Shipping emissions are provided in a report “Documentation for the Commercial Marine Vessel Component of the National Emissions Inventory – Methodology” prepared by Eastern Research Group (ERG, 2010⁴⁶) dated March 30, 2010. The WestJumpAQMS emissions Technical Memorandum Number 7 (Loomis, Morris and Adelman, 2012⁴⁷) describes the off-shore shipping emissions and how they were processed for input into the photochemical grid model.

2.5.8 Biogenic Emissions

WRAP performed a Western Biogenic Emissions Update Study that enhanced the MEGAN biogenic emissions model to better simulate biogenic emissions in the western U.S. The CARMMS used the new enhanced version of MEGAN along with the 2008 WRF 36/12/4 km data to generate hourly gridded speciated biogenic emission inputs for 2008 and the CARMMS 4 km domain. Details on the WRAP Biogenic Emissions Update Study can be found in the study’s final report (Sakulyanontvittaya, Yarwood and Guenther, 2012⁴⁸) with a summary provided in the WestJumpAQMS emissions Technical Memorandum Number 9 on biogenic emissions (Sakulyanontvittaya et al., 2012⁴⁹).

2.5.9 Spatial Allocation

New spatial allocation surrogates were developed at 4 km resolution for the CONUS domain using the latest 2010 CENSUS and other new data. The 4 km surrogate distributions were used directly for disaggregating the county-level emissions to the 4 km grid cells in the CARMMS modeling domain, as well as collapsed to 36 and 12 km resolution for spatial allocation to the 36 km CONUS and 12 km WESTUS domains used in WestJumpAQMS modeling. Table 2-5 summarizes the spatial surrogates to be used for spatial allocation in the CARMMS/WestJumpAQMS SMOKE emissions modeling. More details are provided in the WestJumpAQMS emissions Technical Memorandum Number 13 on SMOKE modeling parameters (Adelman, Loomis and Morris, 2013⁵⁰).

⁴⁴ <http://www.cmu.edu/ammonia/>

⁴⁵ http://www.wrapair2.org/pdf/Memo8_AmmoniaSources_Feb28_2013review_draft.pdf

⁴⁶ http://www.epa.gov/ttn/chief/net/nei08_alm_popup.html

⁴⁷ http://www.wrapair2.org/pdf/OffshoreShippingEmissionsMemo_7WestJumpAQMS_Jan23_2012.pdf

⁴⁸ http://www.wrapair2.org/pdf/WGA_BiogEmissInv_FinalReport_March20_2012.pdf

⁴⁹ http://www.wrapair2.org/pdf/Memo_9_Biogenics_May9_2012_Final.pdf

⁵⁰ http://www.wrapair2.org/pdf/Memo13_Parameters_Feb28_2013review_draft.pdf

Table 2-5. Spatial surrogate distributions to be used in the SMOKE emissions modeling spatial allocations.

Shapefile	Description	Type	Year	Source
cty_pophu2k_revised	U.S. County Boundaries	Polygon	2005	U.S. Census Bureau
pophu_bg2010	Population/ Housing	Polygon	2010	U.S. Census Bureau
rd_ps_tiger2010	Roadways	Line	2010	U.S. Census Bureau
waterway_ntad2011	Waterways	Line	2010	U.S. Bureau of Transport Statistics
rail_tiger2010	Railways	Line	2010	U.S. Census Bureau
exits**	Highway Exits	Point	2010	ESRI
mjrds**	Major Roads	Line	2010	ESRI
transterm**	Transportation Terminals	Point	2010	ESRI
fema_bsf_2002bnd	Building footprints	Polygon	2010	FEMA
heating_fuels_acs0510_c2010	Home heating fuels	Polygon	2010	U.S. Census Bureau

2.5.10 Temporal Allocation

Temporal profiles are available from the U.S. EPA for a wide range of emissions sources. While the majority of the temporal profiles available from the EPA represent nationally averaged emissions sources, state-specific monthly profiles exist for prescribed fires, wildfires, livestock, and some mobile sources. For most sources the emissions modeling temporal allocations were based on the U.S. EPA temporal profiles distributed with the 2008 NEIv2.0⁵¹ (filename: amptpro_2008aa_us_can_revised_06oct2011_v0.txt). Several source categories use episode emissions that already have hourly emissions so will not use the temporal allocation profiles. These emissions categories include: large point sources with measured hourly CEM emissions; on-road mobile sources that use the MOVES monthly weekday/weekend day hourly emissions; biogenic emissions from MEGAN; and fire emissions from DEASCO3. The EPA default cross walk file between SCC codes and temporal allocations is available on the NEIv2.0 website⁵².

2.5.11 Chemical Speciation

The U.S. EPA develops speciation profiles from information stored in the SPECIATE database⁵³. The SPECIATE database is the official repository of volatile organic compound (VOC) and particulate matter (PM) emissions source profiles for different categories of emissions sources. CARMMS SMOKE emissions modeling used the SPECIATE Version 4.3 database released in September 2011 that contains 5,592 profiles of chemical mass fractions from source testing conducted by EPA, state agencies, or published in the literature since the 1970's. Of the profiles in SPECIATE V4.3, 3,570 are for PM sources, 1,775 are for VOC sources, and 247 are for other gases, such as mercury. The most recent update to the SPECIATE database occurred with the release of version 4.4 in February 2014 that includes 5,728 speciation profiles for VOC, PM and mercury. SPECIATE 4.4 was released after CARMMS conducted most of its emissions modeling.

Part of the speciation process for VOCs includes converting inventory reactive organic gases (ROG) to total organic gases (TOG). This step is required because inventoried VOC excludes ethane and methane in the mass of total VOC while the speciation profiles include ethane and

⁵¹ <http://www.epa.gov/ttnchie1/net/2008inventory.html>

⁵² ftp://ftp.epa.gov/EmisInventory/2008v2/doc/scc_eisector_xwalk_2008neiv2.xlsx

⁵³ <http://www.epa.gov/ttnchie1/software/speciate/>

methane. Before the speciation profiles can be applied to the inventory, the inventory VOC must be scaled up to account for the missing methane mass. SCC-specific ROG-to-TOG conversion factors are included with the speciation profiles to prepare the inventories for speciation.

The CARMMS CAMx photochemical grid modeling used the Carbon Bond version 05 (CB05) chemical mechanism (Yarwood et al., 2005⁵⁴). The SMOKE emissions modeling was performed using CB05 speciation profiles, based on the SPECIATE V4.3 database, and ROG-to-TOG conversion factors. The Speciation Tool is an interface to the SPECIATE database that develops CB05 VOC speciation profiles for use in the SMOKE emissions modeling. The exception to using the SPECIATE V4.3 VOC speciation profiles was for the WRAP Phase III Basins where Basin-specific CB05 VOC speciation profiles were used for O&G VOC emissions.

2.5.12 Emissions Quality Assurance and Quality Control

The emissions modeling quality assurance (QA) and quality control (QC) procedures developed as part of the WRAP Regional Modeling Center are being used in the CARMMS and WestJumpAQMS emissions modeling (Adelman, 2004). The 2008 base case emissions are processed by major source category in several different “streams” of emissions modeling. This is done in order to assist in the QA/QC of the emissions modeling as it is much easier to identify potential issues in the emissions fields when analyzing single source categories at a time. Each stream of emissions modeling generates a pre-merged CAMx-ready emissions model input with all pre-merged emissions inputs merged together to generate the final CAMx-ready two-dimensional gridded low-level (layer 1) and point source emission inputs. Table 2-6 lists an example of separate streams of emissions modeling by source category that can be used. Also shown in Table 2-6 are the source of the emissions, processing comments and the temporal allocation strategy whose options are as follows:

- Single day per year (aveday_yr)
- Single day per month (aveday_mon)
- Typical Monday, Weekday, Saturday, Sunday per year (mwdss_yr)
- Typical Monday, Weekday, Saturday, Sunday per month (mwdss_mon)
- Emissions estimated for each model simulation day (daily)
- Emissions estimated for each model simulation day with temporal profiles generated with average daily meteorology (daily met)
- Emissions estimated for each model simulation day with temporal profiles generated with hourly meteorology (hourly met)

⁵⁴ http://www.camx.com/publ/pdfs/cb05_final_report_120805.aspx

Table 2-6. Emissions processing categories and temporal allocation approach for 2008 Base Case emissions modeling.

No.	Emissions Processing Category (Abbr)	Inventory Source	Temporal	Processing Comments
1	Nonpoint/Area (nonpt)	NEI	mwdss_mon	Remove oil & gas, agricultural NH ₃ , and dust;; includes commercial marine and rail
2	Livestock NH ₃ (lv)	NEI	mwdss_mon	Do not apply met-based temporal profiles; separate out for possible sensitivity later
3	Fertilizer NH ₃ (ft)	NEI	mwdss_mon	Group with lv as a full agricultural NH ₃ sector (ag)
4	Fugitive and Road Dust (fd)	NEI	mwdss_mon	Includes paved and unpaved road dust; apply transport factors but not met factors
5	Residential Wood Combustion (rwc)	NEI	mwdss_mon	Do not apply met-based temporal profiles; separate out for possible sensitivity later
6	Area Oil & Gas from P3 (ogp3)	WRAP P3	mwdss_mon	Basin specific speciation profiles and spatial surrogates (includes Permian Basin)
7	Area Oil and Gas from NEI (ognei)	NEI	MWDSS_mon	Use default speciation and allocations
8	Nonroad mobile (nr)	NEI	mwdss_mon	Includes NMIM commercial marine and rail
9	MOVES RPD (rpd)	MOVES	hourly met	
10	CEM Point (ptcem)	NEI08/CAMD	daily	Anomalies removed from 2008 CAMD data
11	Non-CEM Point (ptncem)	NEI08	mwdss_mon	Removed oil & gas sources from NEI and transferred to ptognei sector
12	Point Oil & Gas from P3 (ptogp3)	WRAP P3	mwdss_mon	WRAP Phase III inventory and Permian Basin
13	Point Oil & Gas from NEI (ptognei)	WRAP NEI	mwdss_mon	Remove NEI oil and gas emissions for counties in WRAP P3/Permian Basins
14	Point Fires (ptfire)	FINN or SMARTFIRE	daily	
15	Commercial Marine (ptseca)	NEI	aveday_mon	Latest version from Emissions Control Area (ECA) rule
16	Lightning NO _x (lnox)		hourly met	Gridded hourly NO emissions tied to WRF convective rainfall (optional)
17	Sea salt (ss)		hourly met	Surf zone and open ocean PM emissions (Optional)
18	Windblown Dust (wbd)	TBD	hourly met	WRAP WBD model one option
19	MEGAN Biogenic (bg)	MEGAN2.1	hourly met	Use new versions of MEGAN V2.10 updated by WRAP for the western U.S.
20	Mexico Area (mexar)	Mexico NEI	mwdss_mon	Mexico inventory projected from 1999 to 2008
21	Mexico Point (mexpt)	Mexico NEI	mwdss_mon	Mexico inventory projected from 1999 to 2013
22	Mexico Mobile (mexmb)	Mexico NEI	mwdss_mon	Mexico inventory projected from 1999 to 2013
23	Canada Area (canar)	Canada NPRI	mwdss_mon	Latest Environment Canada Inventory
24	Canada Point (canpt)	Canada NPRI	mwdss_mon	Latest Environment Canada Inventory
25	Canada Mobile (canmb)	Canada NPRI	mwdss_mon	Latest Environment Canada Inventory
26+	BLM Planning Areas	BLM	Mwdss_mon	Separate processing of O&G and mining emissions in each BLM Planning Area

Separate QA/QC is performed for each separate stream of emissions processing and in each step. SMOKE includes advanced quality assurance features that include error logs when emissions are dropped or added. The QA/QC procedures developed under the WRAP RMC will be used (Adelman, 2004) that includes visual displays that such as:

- Spatial plots of the hourly emissions for each major species (e.g., NO_x, VOC, some speciated VOC, SO₂, NH₃, PM and CO);
- Vertical average emissions plots for major species and each of the grids;
- Diurnal plots of total emissions by major species and by state; and
- Summary tables of emissions for major species for each grid and by major source category.

This QA information will be examined against the original point and area source data and summarized in an overall QA/QC assessment.

Scripts to perform the emissions merging of the appropriate biogenic, on-road, non-road, area, low-level, fire, and point emission files were written to generate the CAMx-ready two-dimensional day-specific hourly speciated gridded emission inputs. The point source and, as available, elevated fire emissions were processed into the day-specific hourly speciated emissions in the CAMx-ready point source format.

The resultant CAMx model-ready emissions were subjected to a final QA using spatial maps, vertical plots and diurnal plots to assure that: (1) the emissions were merged properly; (2) CAMx inputs contain the same total emissions; and (3) to provide additional QA/QC information.

2.6 2008 Base Case Modeling and Model Performance Evaluation

WestJumpAQMS performed a CAMx 2008 4 km Base Case simulation for the CARMMS 4 km modeling domain and conducted a model performance evaluation. The CARMMS model performance evaluation was documented in Section 4.5.3 in the WestJumpAQMS final report (ENVIRON, Alpine and UNC, 2013⁵⁵). The CARMMS study intended to rely on the WestJumpAQMS CAMx model performance evaluation that focused on monthly and annual model performance statistics across the 4 km CARMMS domain for ozone, PM_{2.5} and related species. However, when presenting the CARMMS 2008 Base Case modeling and model performance evaluation results to the IAQRT at a February 28, 2014 meeting, the IAQRT requested that more model performance information be provided. In particular, the IAQRT requested that ozone model performance statistics be calculated using a 60 ppb observed ozone cut-off concentration instead of 40 ppb as used by WestJumpAQMS, and that model performance statistics be provided down to an individual monitoring site. Thus, CARMMS calculated additional ozone model performance statistics using the 60 ppb ozone cut-off and packaged up all of the WestJumpAQMS model performance products for the 4 km CARMMS domain and 2008 Base Case simulation. The result was a 72 Mb zipped file of model performance products that had over 4,500 model performance statistics and displays that

⁵⁵ http://www.wrapair2.org/pdf/WestJumpAQMS_FinRpt_Finalv2.pdf

summarized model performance down to the individual monitoring site for each month and for each day of 2008 across the 4 km CARMMS domain. The zipped file of model performance products was provided to the IAQRT.

Appendix B summarizes the CARMMS CAMx 2008 Base Case simulation and model performance evaluation across the 4 km CARMMS domain, including ozone model performance statistics using a 60 ppb observed ozone cut-off threshold as recommended by EPA. The CARMMS CAMx Base Case simulation achieved EPA's ozone model performance goals, except in the winter months (Jan, Feb, Nov and Dec) when a 60 ppb observed ozone cut-off is used. The highest winter ozone events in the CARMMS 4 km domain occur during the winter ozone episodes in the Uinta Basin under cold pool shallow inversion conditions or stratospheric ozone intrusions events that the CARMMS modeling system was either not configured to simulate or has difficulty simulating, respectively. The CARMMS CAMx Base Case simulation also mostly achieved the PM Model Performance Criteria. More details on the CARMMS 2008 4 km base case simulation and model performance evaluation are provided in Appendix B.

3.0 FUTURE YEAR EMISSIONS

The meteorological base year for the CARMMS modeling is 2008. The development of the 2008 Base Case modeling database and emissions scenario was described in Chapter 2. In this section, we describe the development of the future year emissions scenario. The future year emissions scenario modeled is 2021. Projecting future year oil and gas (O&G) emissions has many uncertainties as it depends on economic conditions (e.g., price of natural gas and oil), identification of new O&G plays, availability of exploration and development equipment and regulatory requirements. For CARMMS, future year O&G emissions were developed for a range of potential outcomes that would hopefully bound the actual future year O&G development in the region. CARMMS developed three levels of 2021 future year O&G development within the BLM Colorado Planning Areas:

- High Development Scenario;
- Low Development Scenario; and
- Medium Development Scenario, which is a mitigated version of the High Development Scenario.

There are four general types of future year emissions addressed in CARMMS:

1. BLM-authorized (Federal lands) and other (non-Federal lands) oil and gas and mining emissions within the Colorado BLM planning areas (as well as the BLM Farmington Field Office in northern New Mexico);
2. Oil and gas and other development areas outside of Colorado/northern New Mexico BLM Planning Areas;
3. Remainder future year anthropogenic emissions; and
4. Emissions related to the 2008 base year that remained unchanged in the future year scenarios.

3.1 Western Colorado BLM Planning Area Oil and Gas Emissions

To address emissions from future BLM-authorized (Federal lands) and non-BLM-authorized (non-Federal lands) oil and gas development in the western Colorado planning areas, CARMMS has developed several emission calculators. Existing emissions calculators were improved under CARMMS and representative calculators for “typical” crude oil, conventional gas (with condensate), coal bed natural gas (CBNG), and shale gas within the region have been developed. New information has been incorporated for drilling times; engine configurations; condensate and produced water production; well pad versus offsite gas treatment and storage; well-head, infield, and pipeline compression; and gas/oil production. The ability to readily modify input assumptions, such as production parameters, emission control assumptions, and wellhead equipment configurations, has also been incorporated into the calculators.

The refined emission calculators were used to develop the 2021 future-year O&G emissions inventories for the eight western Colorado BLM planning areas. The O&G emission calculators were also updated using information provided by the BLM New Mexico Farmington Field Office (FFO) petroleum engineers to estimate future year O&G emissions for the Mancos Shale Development area in northern New Mexico.

The following sections summarize the emission calculators used to estimate the O&G and mining emissions for western Colorado and northern New Mexico. Details on the emission calculators are provided in two Technical Memorandums (Grant, Zapert and Morris, 2013a,b) that are included as Appendices C and D.

3.1.1 Overview of Calculators

Emission calculators have been developed for each of the following well types.

- Conventional gas
- Conventional oil
- Shale gas
- Coalbed natural gas (CBNG)

For each well type, a separate self-contained emission calculator spreadsheet contains all of the inputs and calculations needed to generate well site emissions.

Additionally, a calculator has been developed to estimate midstream emissions for each area. The midstream emission calculator draws upon Colorado Department of Public Health (CDPHE) Air Pollutant Emission Notice (APEN) emissions for base year emission estimates. Future year midstream emission projections are dependent on the change in oil and gas production in a given planning area which can be updated based on linkages to the by well type emission calculators.

3.1.2 Pollutants

The emission calculators include estimates of emissions of criteria air pollutants (CAPs), greenhouse gases (GHGs), and hazardous air pollutants (HAPs) as follows:

- Criteria Pollutants
 - Carbon monoxide (CO)
 - Nitrogen oxides (NO_x)
 - Particulate matter less than or equal to 10 microns in diameter (PM₁₀)
 - Particulate matter less than or equal to 2.5 microns in diameter (PM_{2.5})
 - Sulfur dioxide (SO₂)
 - Volatile Organic Compounds (VOCs)
- Greenhouse Gases⁵⁶
 - Carbon dioxide (CO₂)
 - Methane (CH₄)
 - Nitrous oxide (N₂O)
- Hazardous Air Pollutants (HAPs)⁵⁷

⁵⁶ Note that the CARMMS PGM modeling does not use Greenhouse Gas (GHG) emissions, but the emission calculators provide GHG emission estimates so they can be reported in the RMPs.

While lead (Pb) is a criteria pollutant, emissions of lead in the BLM western Colorado planning areas due to O&G and mining activities are extremely low and are therefore not included in this analysis.

HAP emissions were estimated for each emissions source. For oil and gas emissions sources, HAP emissions from venting and combustion source categories were estimated for formaldehyde, n-hexane, benzene, toluene, ethylbenzene, and xylenes (BTEX).

Anthropogenic greenhouse gas emission inventories typically include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and fluorinated gases. Fluorinated gases are not expected to be emitted in appreciable quantities by any category considered in this emission inventory and were therefore not included in this analysis.

Although the CARMMS emissions calculators calculate HAP and GHG emissions for oil and gas sources, the CARMMS PGM modeling do not use these emissions so they are not included in this report.

3.1.3 Temporal

The calculators estimate annual emissions associated with oil and gas exploration. Baseline emissions are estimated for 2011 with annual emission forecasts made for every year out to 10 years (2021).

3.1.4 Calculator Inputs

The emission calculator for each well type allows for specification of the following inputs.

- Base year oil and gas activity (gas production, oil production, spud counts, active well counts)
- Well decline estimates
- Level of control by source category
- Gas composition
- Equipment configurations (e.g. drill rigs, fracing rigs)
- Gas venting activity (e.g. completions, blowdowns)

The midstream emission calculator includes estimates of base year 2011 gas plant and compressor station emissions are taken from CDPHE APEN data. Base year midstream emissions are projected to future years based upon the gas production in each planning area.

3.1.5 Emission Calculations

Emission calculations for all emission-generating activities were developed based on typical emission inventory methodology. Methods used to estimate emissions from each source category are explained in detail in Appendix C (Grant, Zapert and Morris, 2013a). For each source category, emissions for the 2011 baseline were estimated. Emissions were then

⁵⁷ Note that the CARMMS PGM modeling does not use HAPs emissions, but the emission calculators provide HAPs emission estimates so they can be reported in the RMPs.

forecasted to future years, accounting for activity growth and for applicable sources emissions controls.

The methodologies described here are used consistently in all four calculators by well type; however the input data of each calculator was selected to best reflect the operational characteristics of each well type (oil, gas, CBNG, and shale gas) and thus obtained from literature sources including the following Air Quality Technical Support Documents (AQTSD) from Colorado field office planning areas and BLM emission calculators:

- White River AQTSD (URS, 2012a)
- Colorado River Valley AQTSD (URS, 2012b)
- Grand Junction AQTSD (BLM, 2012b)
- Uncompahgre AQTSD (in preparation)
- BLM Crude Oil Well Gas Emission Calculator
- BLM Coalbed Natural Gas Well Emission Calculator

Emissions are generated in three main phases of oil and gas systems:

- Emissions from Well Construction and Development
- Emissions from the Production Phase (occurring at-or-nearby the well pad)
- Emissions from Midstream Sources (Central Gas Compression and Processing)

The methodologies implemented to estimate base year and future year emissions from oil and gas sources are explained in Appendix C (Grant, Zapert and Morris, 2013a) and covered the following source categories:

- Well pad construction and development:
 - Well pad, access road and pipeline construction equipment;
 - Well pad, access road and pipeline construction traffic;
 - Drilling and completion equipment;
 - Fracing equipment;
 - Refracing equipment;
 - Drilling and well completion traffic;
 - Well pad, access road and pipeline construction wind erosion; and
 - Well completion venting.
- Production phase emissions:
 - Well workover equipment;
 - Production traffic;
 - Blowdown venting;
 - Well recompletion venting;
 - Pneumatic devices and fugitive components;

- Water injection pumps;
- Compressor station maintenance traffic exhaust and fugitive dust;
- Condensate or oil tanks flashing and working and breathing losses;
- Loading emissions from condensate and oil tanks;
- Haul trucks traffic emissions;
- Heaters; and
- Dehydrators;
- Midstream sources:
 - Natural gas processing facilities;
 - Natural gas compressor stations; and
 - Gas sweetening.

The oil and gas emission calculators are designed to estimate emissions from both BLM-authorized and non-BLM-authorized activities within the western Colorado BLM planning areas. Emissions were also estimated for coal and uranium mines on federal lands in the western Colorado BLM planning areas. However, unlike the oil and gas emissions, emissions from mines not on federal lands were not estimated and were obtained from the EPA 2020 projections. The emissions for mines on federal lands were estimated for the baseline (2011) and future years and were based on the CDPHE APEN database and available EISs and EAs. Details on the mining emissions are given in Appendix D (Grant, Zapert and Morris, 2013b). Emissions were estimated for the following mines (BLM field office in parenthesis):

- Book Cliffs Area (Grand Junction).
- McClane (Grand Junction).
- Oak Mesa Area (Uncompahgre).
- King (Tres Rios).
- Foidel (Kremmling).
- Deserado (White River).
- Trapper (Little Snake).
- Colowyo (Little Snake).
- Sage Creek (Little Snake).
- West Elk (Uncompahgre).
- Elk Creek (Uncompahgre).

3.2 Oil and Gas Emissions outside of the BLM Western Colorado Planning Areas

The following three sections describe the procedures for estimating baseline and future year oil and gas emissions for areas within the CARMMS 4 km modeling domain but outside of the western Colorado BLM planning areas.

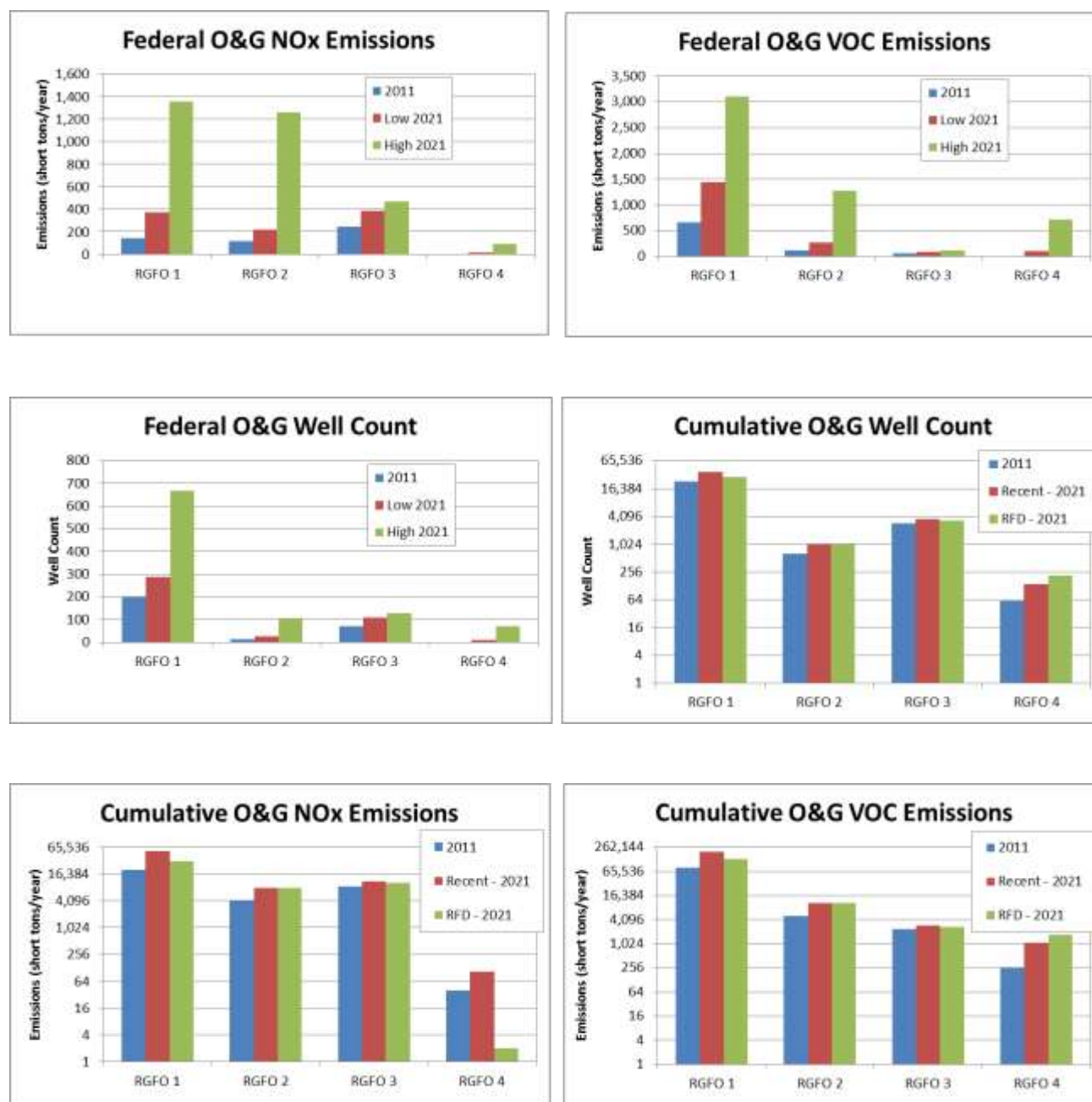
3.2.1 Colorado Royal Gorge Field Office

Baseline and future year oil and gas emissions for the BLM Royal Gorge Field Office⁵⁸ (RGFO) planning area in eastern Colorado were developed by the BLM COSO using RGFO specific oil and gas RFD estimates and air pollutant emissions calculators designed specifically for eastern Colorado oil and gas development / operations. Due to the geographic size and diversity of the RGFO, the RGFO was divided into four unique geographic areas and baseline and projected emissions inventories were developed for each RGFO area. Future year 2021 oil and gas emissions estimates were developed for future “permitted” and “non-permitted” activities. To develop the year 2021 “permitted” oil and gas emissions estimates, the year 2011 APENs emissions for each RGFO area was scaled using the year 2011 oil and gas production data with projected year 2021 oil and gas production data. The APENs based projections account for all permitted source types but do not include non-permitted sources such as pneumatics, small tanks and some fugitives. To account for “non-permitted” activities in the DJ Basin, WRAP Phase III emissions inventories for non-permitted sources and production data were used to develop production average emissions factors for non-permitted sources / activities and these emissions factors were then used with future projected year 2021 production rates to develop a future year 2021 non-permitted oil and gas emissions inventory for the DJ Basin. For eastern and southeastern portions of the RGFO, a CENRAP oil and gas emissions inventory report was used with projected future year 2021 production data to develop future non-permitted oil and gas emissions estimates similar to what was completed for the DJ Basin. For the Raton Basin, oil and gas operators were specifically queried for operations / activities that are not routinely permitted and future projected year 2021 non-permitted emissions estimates for these activities were made using that information. In addition to the “permitted” and “non-permitted” RGFO emissions inventories described above, oil and gas development and production related traffic emissions were developed for year 2021. The “RFD / High” and “Low” emissions scenarios assumed on-the-books controls and the “RFD-Controlled / Medium” scenario assumes the following enhanced emissions controls for future projected Federal oil and gas: no venting during blow-downs, 30% electrification, Tier 4 drill and completion engines, 80% dust control to unpaved roads, 50% dust controls for well-pad and road construction disturbed areas and 50% of small non-permitted condensate tanks are assumed controlled.

The following charts show year 2011 and projected year 2021 RGFO NO_x and VOC emissions estimates and well counts for the CARMMS Low and High modeling scenarios. As shown in the plots, projected year 2021 Federal O&G related emissions for the RFD / High Scenario are higher than projected year 2021 Federal O&G emissions estimates for the Low scenario. For the cumulative plots, future year 2021 cumulative (Federal and non-Federal) emission estimates for the Low Scenario (projected development based on recent development rates) are higher than the RFD / High Scenario and are being driven by the non-Federal oil and gas projection estimates. The current annual non-Federal oil and gas development rates are higher than the

⁵⁸ <http://www.blm.gov/co/st/en/fo/rgfo.html>

RFD projected estimates primarily because the RFD analysis assumes that current annual non-Federal development rates are not sustainable.



3.2.2 South San Juan Basin, New Mexico

Oil and gas emissions for the New Mexico BLM Farmington Field Office in the South San Juan Basin that includes San Juan, Rio Arriba, Sandoval and McKinley Counties were estimated based on oil and gas activity provided by the New Mexico BLM State and Farmington Field Office for the Mancos Shale Play and 2012 WRAP Phase III inventories for oil and gas emissions in the South San Juan basin. Figure 3-1 displays the Mancos Shale oil and gas development area in

northwestern New Mexico in relation to BLM Planning Areas (note that the Mancos Shale extends into southern Colorado Tres Rios Field Office Planning Area). Figure 3-2 displays a detailed map of the Mancos Shale development area; the formation is split into an oil prone area in the south and a gas prone area to the north. The oil development is expected to occur at a rate of approximately 200 wells per year starting around 2015. The development of the gas prone area to the north (dry gas with little or no fluids) is dependent on the price of natural gas and is expected to be intensively developed starting approximately four years after the oil prone area (~2019).

70% of the new O&G emissions due to the Mancos Shale development are assumed to occur on Federal lands (i.e., BLM-authorized) and these emissions will be attributed to the New Mexico BLM Farmington Field Office even though there are small amounts of emissions within the BLM Colorado Tres Rios Field Office Planning Area.



Figure 3-1. Mancos Shale development area (shown with other oil and gas source areas from CARMMS).

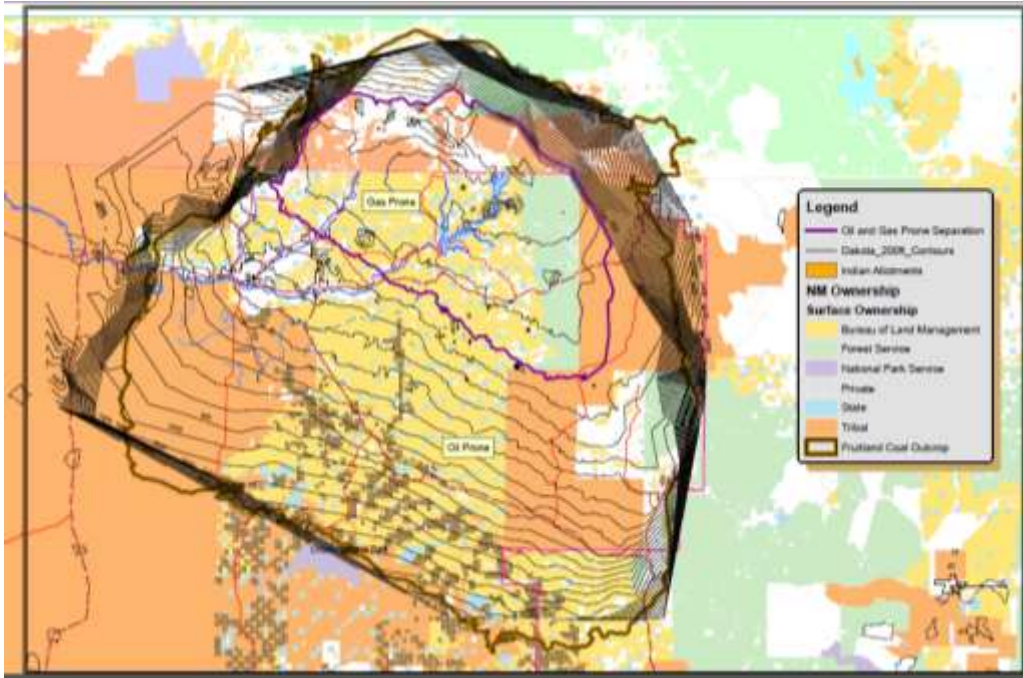


Figure 3-2. Map of oil and gas prone development areas within the Mancos Shale Oil formation primarily in the New Mexico BLM FFO planning area.

To address emissions from future BLM-authorized (Federal lands) and non-BLM-authorized (non-Federal lands) oil and gas development in the South San Juan Basin, BLM commissioned development of Mancos Shale emission calculators. CARMMS emission calculators were modified and adapted to develop two new Mancos Shale emission calculators, one for oil wells and another for gas wells drilled in the Mancos Shale formation. Mancos Shale oil and gas well information has been incorporated for all phases of well development and production emissions to the extent that Mancos Shale specific data was available based on information provided by the BLM New Mexico Farmington Field Office (FFO) petroleum engineers. The ability to readily modify input assumptions, such as production parameters, emission control assumptions, and wellhead equipment configurations, has also been incorporated into the calculators.

The Mancos Shale emission calculators were used to develop the 2021 future-year O&G emissions inventories for oil and gas activity associated with the Mancos Shale formation. The oil and gas emission calculators are designed to estimate emissions from both BLM-authorized and non-BLM-authorized activities for the Mancos Shale formation emissions.

Pollutants included in the Mancos Shale calculators, temporal considerations, and calculator inputs are all consistent with the CARMMS calculators as described in Sections 3.1.2, 3.1.3, and 3.1.4, respectively.

3.2.2.1 Emission Calculations

Emission calculations for all Mancos Shale emission-generating activities were developed based on typical emission inventory methodology. Methods used to estimate emissions from each source category are consistent with the CARMMS Western Colorado Planning Area calculators explained in detail in Appendix C (Grant, Zapert and Morris, 2013a). For each source category, emissions were estimated for all years of activity, accounting for activity growth and for applicable sources, emissions controls.

The methodologies described here are used consistently in both oil well and gas well Mancos Shale calculators; however the input data of each calculator was selected to best reflect the operational characteristics of each well type (oil and gas) and thus obtained from either BLM New Mexico Farmington Field Office (FFO) petroleum engineers provided well characteristics data or from CARMMS Western Colorado oil and gas calculators.

Emissions are generated in three main phases of oil and gas systems:

- Emissions from Well Construction and Development
- Emissions from the Production Phase (occurring at-or-nearby the well pad)
- Emissions from Midstream Sources (Central Gas Compression and Processing)

The methodologies implemented to estimate base year and future year emissions from oil and gas sources are explained in Appendix C (Grant, Zapert and Morris, 2013a) using the emissions calculators for source categories discussed in Section 3.1.5.

Recent trends in gas production in the South San Juan Basin show consistent decline since 2006 (Figure 3-3). Average decline over the 2006 to 2013 period is about 42 billion cubic-feet (BCF) per year, with the largest drop in production occurring from 2012 to 2013 (64 BCF). Over the ten year period from 2011 to 2021, the average annual historical rate of decline would result in a loss of 420 BCF and the most recent, maximum rate of annual decline would result in a loss of 640 BCF. The total gas production estimated to be added to 2021 for the Mancos Shale for the high development scenario is about 510 BCF per year. Given existing midstream capacity and recent declines in gas production in the South San Juan Basin, additional emissions at midstream sources (i.e. compressor stations and gas plants) were assumed negligible for the Mancos Shale development.

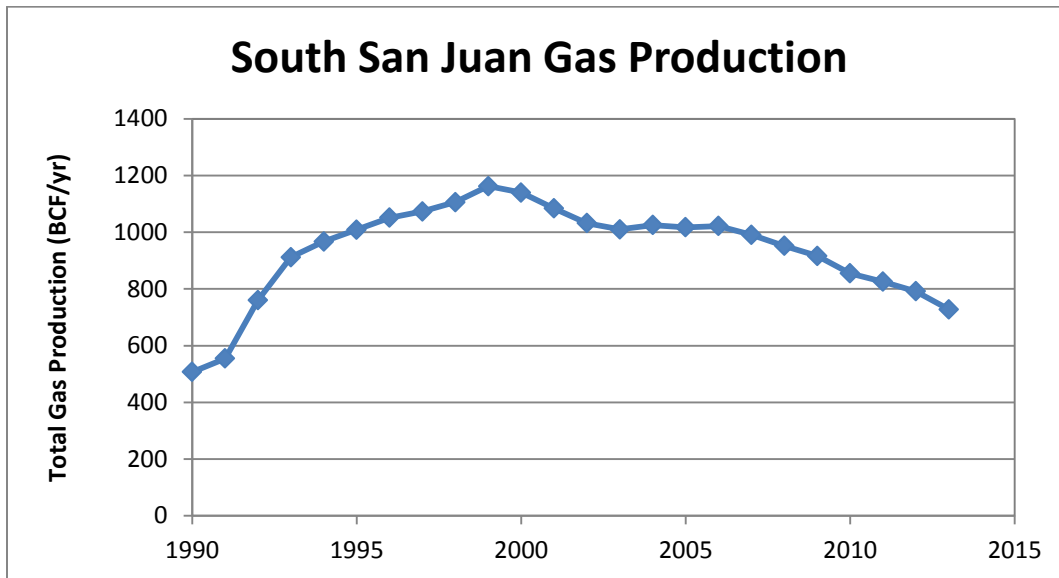


Figure 3-3. Historical gas production in the South San Juan Basin (including Rio Arriba, San Juan, Sandoval, and McKinley Counties).

3.2.3 Uinta Basin, Utah

Baseline and future year emissions associated with oil and gas development in the Uinta Basin have been estimated by AECOM for the BLM Utah State Office (UTSO⁵⁹) under the UTSO Air Resource Management Study (ARMS). The UTSO ARMS is using a 2010 baseline year. More details on the oil and gas emissions for the Uinta Basin are available in the UTSO ARMS documentation (AECOM, 2013⁶⁰).

3.2.4 Southwestern Wyoming

Oil and gas development emissions for southwestern Wyoming were based on recent BLM Environmental Impact Statements (EISs), including those compiled as part of the draft EIS for the Continental Divide-Creston Natural Gas Project⁶¹.

3.3 Other Anthropogenic Emissions

Other anthropogenic emissions (i.e., non O&G and BLM authorized mining sources) for the 2021 future year were based on 2020 emission projections compiled by the 3SAQS that were based on EPA's 2020 projections used in the PM_{2.5} NAAQS rulemaking, which used EPA's 2007v5 modeling platform⁶². Emissions associated with oil and gas emissions within the western Colorado, Royal Gorge, North San Juan Basin, Uinta Basin and southwest Wyoming Basin described in Section 3.2 above were removed from the 2020 3SAQS/NEI to avoid double counting. Similarly, mining emissions on federal lands in the western Colorado BLM planning areas were also removed from the 2020 NEIs and replaced by estimates from the CARMMS calculators.

⁵⁹ <http://www.blm.gov/ut/st/en.html>

⁶⁰ http://www.blm.gov/pgdata/etc/medialib/blm/ut/natural_resources/airQuality.Par.34346.File.dat/UTSO_EmissionsTSD121913.pdf

⁶¹ http://www.blm.gov/wy/st/en/info/NEPA/documents/rfo/cd_creston.html

⁶² <http://www.epa.gov/ttnchie1/emch/>

Details on the development of the 2020 NEI can be found in the 2020 Emissions Technical Support Document (TSD) for the PM_{2.5} NAAQS rule (EPA, 2012d⁶³).

3.4 Emissions that Remain at 2008 Levels

The following emission categories from the 2008 Base Case emissions scenario (see Section 2.5) were assumed to remain unchanged for the 2021 future year emission scenarios:

- Biogenic emissions.
- Wildfires, Prescribed Burns and Agricultural Burning emissions.
- Lightning emissions.
- Sea Salt emissions.
- Windblown Dust emissions.
- Emissions from Canada, Mexico and offshore sources (used in the 2021 36/12 km simulation used to provide boundary conditions for the 4 km CARMMS domain).

3.5 Western Colorado BLM Planning Area Oil and Gas Emissions

The emission calculators were used to generate O&G emissions for the eleven-year period of 2011-2021 for 8 western Colorado BLM Planning Areas:

- Roan Plateau portion of the Colorado River Valley Field Office (CRVFO)
- CRVFO outside of the Roan Plateau
- Grand Junction Field Office (GJFO)
- Kremmling Field Office (KFO)
- Little Snake Field Office (LSFO)
- Tres Rios Field Office (TRFO)
- Uncompahgre Field Office (UFO)
- White River Field Office (WRFO)

For each year between 2011-2021, the emissions calculators were used to estimate O&G emissions for upstream (well site) and midstream emission sources and for O&G development on Federal and non-Federal lands within in each of the 8 western Colorado BLM Planning Areas listed above.

3.5.1 2021 High, Low and Medium Development Scenarios

The emissions calculators were used to generate O&G emissions within the 8 western Colorado BLM Planning Areas for 2021 High, Low and Medium Development Scenarios. The High Development Scenario is based on BLM COSOs estimates of RFD O&G future development within these 8 BLM Planning Areas. The Low Development Scenario is based on historical 5-year average O&G development over the 2008-2012 period that was used to grow O&G

⁶³ http://epa.gov/ttn/chief/emch/2007v5/2007v5_2020base_EmisMod_TSD_13dec2012.pdf

emissions to each year between 2011-2021. Applicable State and Federal controls are applied to the O&G emissions starting in the year that they are required.

The Low Development Scenario assumes 25,710 total active wells in 2021 within the 8 western Colorado BLM Planning Areas with 8,121 wells (32%) on Federal and 17,589 wells (68%) on non-Federal lands. The High Development Scenario assumes 41,033 total active wells, 1.6 times higher than the Low Development Scenario, that are split as 18,347 on Federal (45%) and 22,686 (55%) on non-Federal lands. The 2021 Medium Development Scenario has the same number of wells as the High Development Scenario but assumes additional levels of controls beyond the application of existing state and federal requirements. The Medium Development Scenario assumes additional control of engine and fugitive emission sources for all phases of well-site operation for wells drilled on Federal land after 2015 as follows:

- All development (drilling / completion / fracing) engines will be Tier 4. Tier 4 gen-set standards will be applied for all engines with a horsepower >750; final Tier 4 standards will be applied to all engines with horsepower <750.
- All condensate tank, oil tank, and dehydrator emissions are captured and controlled by VRUs (assumed 95% control efficiency attained by vapor recovery).
- All pneumatic devices are low-bleed or no bleed. Assumed 50% of devices are low-bleed (6 cfh) and 50% of devices are no-bleed.
- Assume that 30% of production engines are powered by electricity (applies to all well-site engines).
- Assume 80% dust control for unpaved road traffic.
- All truck loading emissions are captured and controlled by VRU.

Table 3-1 and Figure 3-4 compare the total emissions from the 8 western Colorado BLM Planning Areas for the 2021 High, Low and Medium Development emission scenarios.

Table 3-1. Comparison of oil and gas emissions (tons per year, TPY) from the 8 western Colorado BLM Planning Areas for 2021 High, Low and Medium Development emission scenarios.

Scenario	VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂
All Wells						
Low	44,025	22,715	25,078	4,425	1,270	259
Medium	78,654	45,453	51,983	7,224	2,355	1,145
High	95,427	46,014	56,666	9,482	2,714	1,145
Federal Emissions						
Low	13,950	7,369	7,939	1,233	424	190
Medium	30,254	22,811	26,003	2,763	1,118	971
High	47,007	23,371	29,879	4,996	1,452	972
Non-Federal Emissions						
Low	30,075	15,346	17,139	3,191	846	69
Medium	48,399	22,642	25,979	4,461	1,237	174
High	48,420	22,642	26,787	4,486	1,262	174

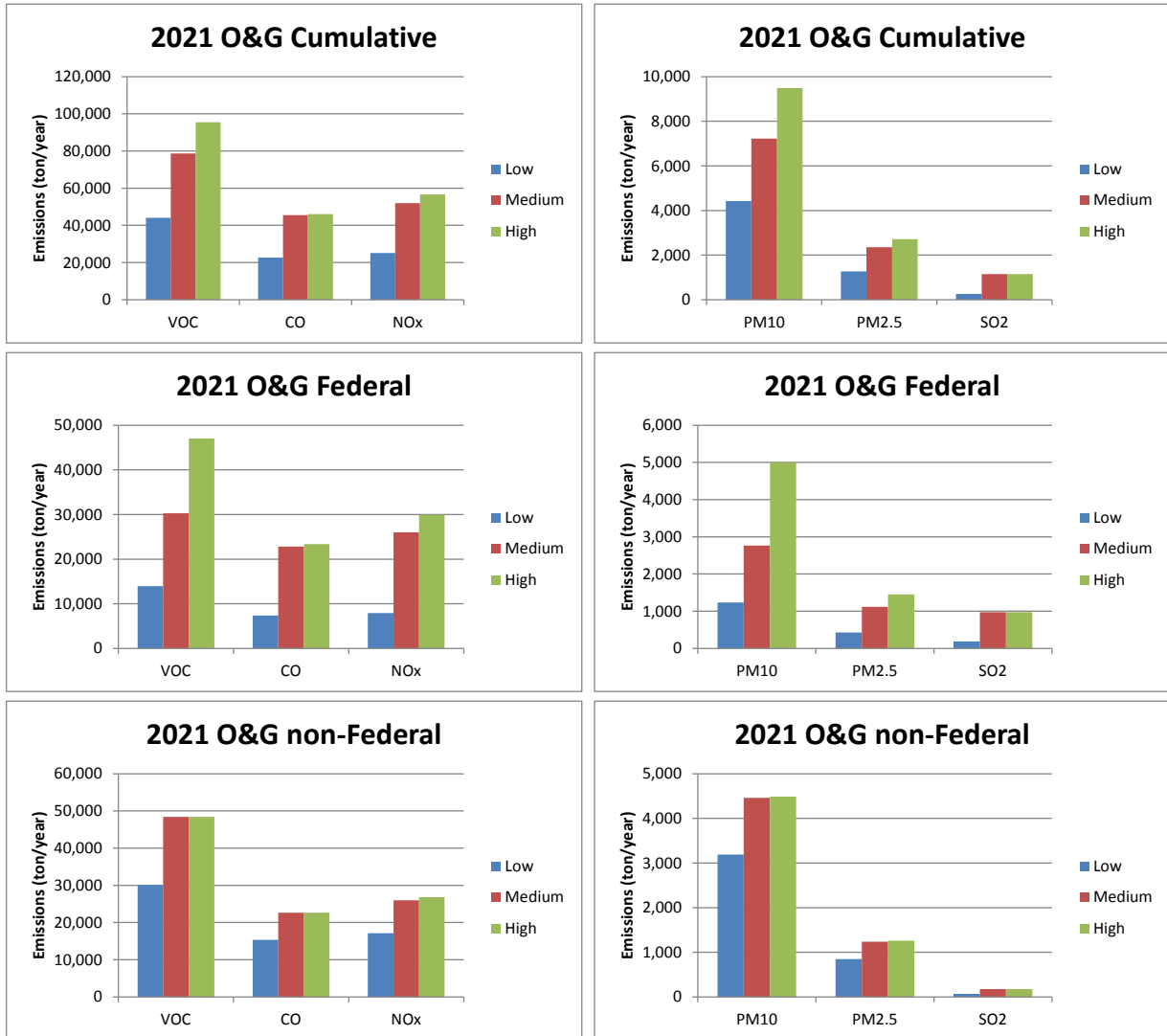


Figure 3-4. Comparison of total oil and gas emissions from the 8 western Colorado BLM Planning Areas for the 2021 High, Low and Medium Development Scenarios.

3.5.2 2021 High, Low and Medium Development Scenarios

The CARMMS air quality modeling results for the 2021 High, Low and Medium Development Scenarios are presented in Chapter 5. In this section we summarize the emissions for the 8 western Colorado BLM Planning Areas and the three 2021 emission scenarios. Figure 3-5 and Table 3-2 display the NO_x and VOC O&G emissions for the 8 western Colorado BLM Planning Areas and the 2011 current year emissions and the three 2021 emission scenarios stratified by O&G emissions on Federal and non-Federal lands. Summary spreadsheets (not shown) also include emissions stratified by upstream vs. midstream and provide emissions per well. Across the 8 Colorado Planning Areas, the 2021 High Development Scenario O&G NO_x and VOC emissions are, respectively, 2.6 and 2.7 times greater than in 2011, whereas the 2021 Low Development Scenario are 1.1 and 1.3 times greater than 2011, so the 2021 Low Development Scenario emissions are very similar to 2011 O&G emission levels. The controls assumed in the

2021 Medium Development Scenario reduce O&G NO_x and VOC emissions by -8.2% and -17.6% from the 2021 High Development Scenario.

Table 3-2a. Summary of oil and gas NO_x and VOC emissions within the 8 western Colorado BLM Planning Areas for the 2011 current year and 2021 High Development emission scenarios (2021 emissions include both existing and new O&G sources).

2011	NO _x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	1,036	3,575	4,611	2,596	10,407	13,003
Roan (CRVFO)	1,280	2,158	3,438	1,962	3,356	5,318
GJFO	535	2,976	3,511	634	4,032	4,665
KFO	69	40	108	150	138	288
LSFO	741	189	930	1,493	415	1,907
TRFO	879	4,551	5,431	837	3,243	4,080
UFO	61	76	137	55	65	120
WRFO	3,296	736	4,032	4,433	1,052	5,485
Grand Total	7,896	14,301	22,198	12,159	22,708	34,867
2021 High Scenario	NO _x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	1,679	4,639	6,318	5,070	14,287	19,357
Roan (CRVFO)	1,835	1,856	3,692	2,971	3,425	6,395
GJFO	7,670	10,291	17,961	13,744	20,230	33,974
KFO	236	221	458	424	326	750
LSFO	2,320	1,723	4,042	3,334	2,349	5,683
TRFO	3,386	5,096	8,482	2,289	3,861	6,150
UFO	612	1,067	1,679	620	1,082	1,702
WRFO	12,141	1,893	14,034	18,556	2,859	21,415
Grand Total	29,879	26,787	56,666	47,007	48,420	95,427
Difference	NO _x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	62%	30%	37%	95%	37%	49%
Roan (CRVFO)	43%	-14%	7%	51%	2%	20%
GJFO	1333%	246%	412%	2069%	402%	628%
KFO	244%	455%	322%	183%	136%	160%
LSFO	213%	813%	335%	123%	467%	198%
TRFO	285%	12%	56%	173%	19%	51%
UFO	903%	1302%	1124%	1025%	1565%	1317%
WRFO	268%	157%	248%	319%	172%	290%
Grand Total	278%	87%	155%	287%	113%	174%

Table 3-2b. Summary of oil and gas NO_x and VOC emissions within the 8 western Colorado BLM Planning Areas for the 2011 current year and 2021 Medium Development emission scenarios (2021 emissions include both existing and new O&G sources).

2011	NO_x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	1,036	3,575	4,611	2,596	10,407	13,003
Roan (CRVFO)	1,280	2,158	3,438	1,962	3,356	5,318
GJFO	535	2,976	3,511	634	4,032	4,666
KFO	69	40	109	150	138	288
LSFO	741	189	930	1,493	415	1,908
TRFO	879	4,551	5,430	837	3,243	4,080
UFO	61	76	137	55	65	120
WRFO	3,296	736	4,032	4,433	1,052	5,485
Grand Total	7,896	14,301	22,197	12,159	22,708	34,867
2021 Medium Scenario	NO_x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	1,428	4,459	5,887	3,174	14,283	17,457
Roan (CRVFO)	1,613	1,820	3,433	2,438	3,424	5,862
GJFO	6,517	9,927	16,444	6,158	20,221	26,379
KFO	197	213	410	245	326	571
LSFO	2,092	1,680	3,772	2,690	2,348	5,038
TRFO	2,984	5,033	8,017	1,876	3,860	5,735
UFO	486	1,012	1,498	531	1,081	1,611
WRFO	10,686	1,835	12,522	13,142	2,857	15,999
Grand Total	26,003	25,979	51,983	30,254	48,399	78,654
Difference	NO_x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	38%	25%	28%	22%	37%	34%
Roan (CRVFO)	26%	-16%	0%	24%	2%	10%
GJFO	1118%	234%	368%	871%	402%	465%
KFO	185%	433%	276%	63%	136%	98%
LSFO	182%	789%	306%	80%	466%	164%
TRFO	239%	11%	48%	124%	19%	41%
UFO	696%	1232%	993%	865%	1563%	1243%
WRFO	224%	149%	211%	196%	172%	192%
Grand Total	229%	82%	134%	149%	113%	126%

Table 3-2c. Summary of oil and gas NO_x and VOC emissions within the 8 western Colorado BLM Planning Areas for the 2011 current year and 2021 Low Development emission scenarios (2021 emissions include both existing and new O&G sources).

2011	NO_x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	1,036	3,575	4,611	2,596	10,407	13,003
Roan (CRVFO)	1,280	2,158	3,438	1,962	3,356	5,318
GJFO	535	2,976	3,511	634	4,032	4,666
KFO	69	40	109	150	138	288
LSFO	741	189	930	1,493	415	1,908
TRFO	879	4,551	5,430	837	3,243	4,080
UFO	61	76	137	55	65	120
WRFO	3,296	736	4,032	4,433	1,052	5,485
Grand Total	7,896	14,301	22,197	12,159	22,708	34,867
2021 Low Scenario	NO_x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	1,212	3,334	4,546	3,701	10,456	14,157
Roan (CRVFO)	1,248	1,856	3,104	2,208	3,425	5,633
GJFO	819	5,229	6,049	1,203	10,107	11,310
KFO	80	94	175	127	145	272
LSFO	592	389	980	972	536	1,508
TRFO	1,051	5,261	6,313	782	3,931	4,712
UFO	176	127	303	200	140	340
WRFO	2,760	849	3,609	4,758	1,336	6,093
Grand Total	7,939	17,139	25,078	13,950	30,075	44,025
Difference	NO_x Emissions (TPY)			VOC Emissions (TPY)		
BLM Area	Federal	non-Fed	Total	Federal	non-Fed	Total
CRVFO (No Roan)	17%	-7%	-1%	43%	0%	9%
Roan (CRVFO)	-3%	-14%	-10%	13%	2%	6%
GJFO	53%	76%	72%	90%	151%	142%
KFO	16%	136%	60%	-16%	5%	-6%
LSFO	-20%	106%	5%	-35%	29%	-21%
TRFO	20%	16%	16%	-7%	21%	15%
UFO	189%	67%	121%	264%	116%	184%
WRFO	-16%	15%	-11%	7%	27%	11%
Grand Total	1%	20%	13%	15%	32%	26%

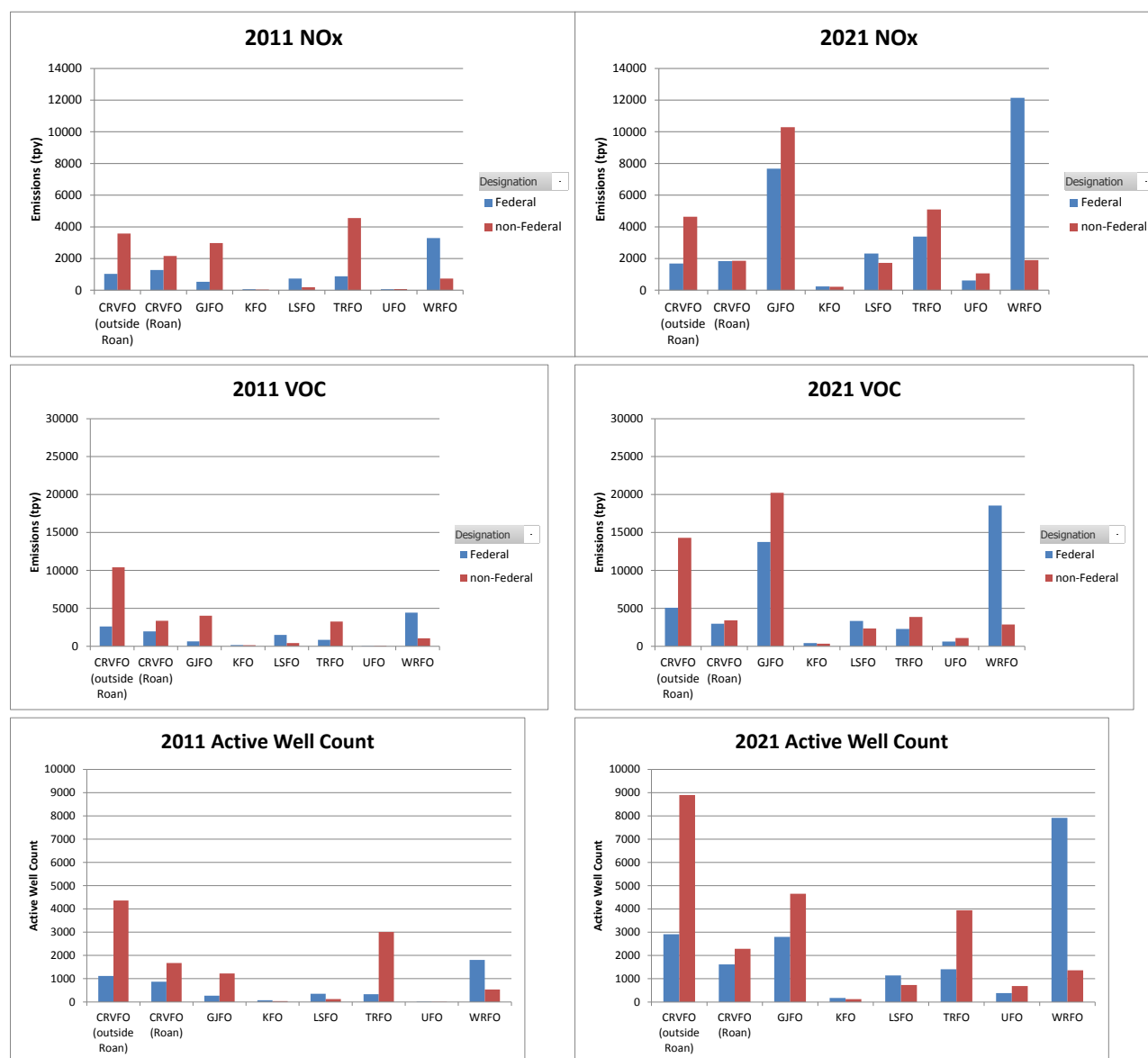


Figure 3-5. NO_x and VOC emissions and well counts from oil and gas development within the 8 western Colorado BLM Planning Areas and for the 2011 current (left) and 2021 High Development Scenario (right) emissions scenarios.

3.6 Future Year Emissions Modeling Procedures

The 2021 future year emissions were processed using the SMOKE emissions model in a similar manner as used for the 2008 Base Case emissions scenario described in Section 2.5. One difference in the 2021 SMOKE emissions modeling was that each source category for which separate ozone and particulate matter contributions are needed was processed in a separate stream in the SMOKE emissions modeling. This resulted in many different streams of SMOKE emissions processing for the three 2021 emission scenarios to provide separate source groups so that the AQ/AQRV impacts can be isolated in the source apportionment modeling.

3.6.1 Non-Oil and Gas Future-Year Emissions Data

For most of the inventory sectors, the 2020 inventory and ancillary emissions data were obtained directly from the 3SAQS modeling platform, which in turn uses data from EPA's 2007v5 modeling platform (EPA, 2012d). Developed by EPA for use in the PM_{2.5} NAAQS RIA, the 2020 inventory represent the best estimate of future year emissions without the implementation of any new controls necessary to attain the current PM_{2.5} annual and 24-hr (35 µg/m³ and 15 µg/m³) and ozone 8-hr (75 ppb) standards (EPA, 2012d). These emissions reflect rule promulgated or under reconsideration as of July 2012.

A summary of the 2007v5 modeling platform 2020 inventory is provided below and additional details are available from EPA (EPA, 2012d).

CEM Point: For Electric Generating Units (EGUs) with Continuous Emissions Monitors (CEMs), EGU-specific emissions estimates were obtained from the Integrated Planning Model (IPM⁶⁴), version 4.10 accounting for controls from the Cross-State Air Pollution Rule (CSAPR⁶⁵) and Mercury and Air Toxics Standard (MATS⁶⁶) rulemakings.

Non-CEM Point: Projection factors and percent reductions reflect CSAPR comments and emission reductions due to national rules, control programs, plant closures, consent decrees and settlements and 1997 and 2001 ozone State Implementation Plans in NY, CT, and VA. EPA used projection approaches for corn ethanol and biodiesel plants, refineries and upstream impacts from the Energy Independence and Security Act of 2007 (EISA). Terminal area forecast (TAF) data aggregated to the national level were used for aircraft to account for projected changes in landing/takeoff activity.

Nonpoint/Area: Agricultural sector projection factors for livestock estimates based on expected changes in animal population from 2005 Department of Agriculture data, updated based on personal communication with EPA experts in July 2012; fertilizer application NH₃ emissions projections include upstream impacts EISA. Fugitive dust projection factors for dust categories related to livestock estimates based on expected changes in animal population and upstream impacts from EISA. Other nonpoint source projection factors that implement CSAPR comments and reflect emission reductions due to control programs. Residential wood combustion projections are based on growth in lower-emitting stoves and a reduction in higher emitting stoves. PFC projection factors reflecting impact of the final Mobile Source Air Toxics (MSAT 2) rule. Upstream impacts from EISA, including post-2007 cellulosic ethanol plants are also reflected.

Off-road Mobile: Other than for California, this sector uses data from a run of NMIM that utilized NONROAD2008a, using future-year equipment population estimates and control programs to the year 2020 and using national level inputs. Final controls from the final locomotive-marine and small spark ignition OTAQ rules are included. California-specific data were provided by California Air Resources Board (CARB).

⁶⁴ <http://www.icfi.com/insights/products-and-tools/ipm>

⁶⁵ <http://www.epa.gov/crossstaterule/>

⁶⁶ <http://www.epa.gov/mats/>

Aircraft/locomotive/marine: For all states except California, projection factors for Class 1 and Class 2 commercial marine and locomotives, which reflect final locomotive-marine controls. California projected year-2020 inventory data were provided by CARB.

Offshore shipping: Base-year 2007 emissions grown and controlled to 2020, incorporating controls based on Emissions Control Area (ECA) and International Marine Organization (IMO) global NO_x and SO₂ controls.

On-road Mobile, not including refueling: MOVES2010b emissions factors for year 2020 were developed using the same representative counties, state-supplied data, meteorology, and procedures that were used to produce the 2007 emission factors. California-specific data were provided by CARB. Other than California, this sector includes all non-refueling on-road mobile emissions (exhaust, evaporative, evaporative permeation, brake wear and tire wear modes).

On-road Refueling: Uses the same projection and processing approach as the on-road sector, except for California where EPA projected using MOVES2010b and did not include CARB data.

Canada Sources: Held constant and 2006 levels.

Mexico Sources: Projections from 1999 to 2018.

The ancillary data (spatial/temporal/chemical) were held unchanged from the 3SAQS platform for preparing the 2021 emissions for CAMx. In the 3SAQS platform, the base sets of ancillary data were taken directly from the EPA 2007v5 modeling platform. The 3SAQS made targeted improvements to the ancillary files for counties in the 3-state study region (Figure 3-6). The improvements were focused on the assignments of spatial/chemical/temporal profiles to inventory sources and on developing profiles that best represent the emissions patterns in the 3-state study region.

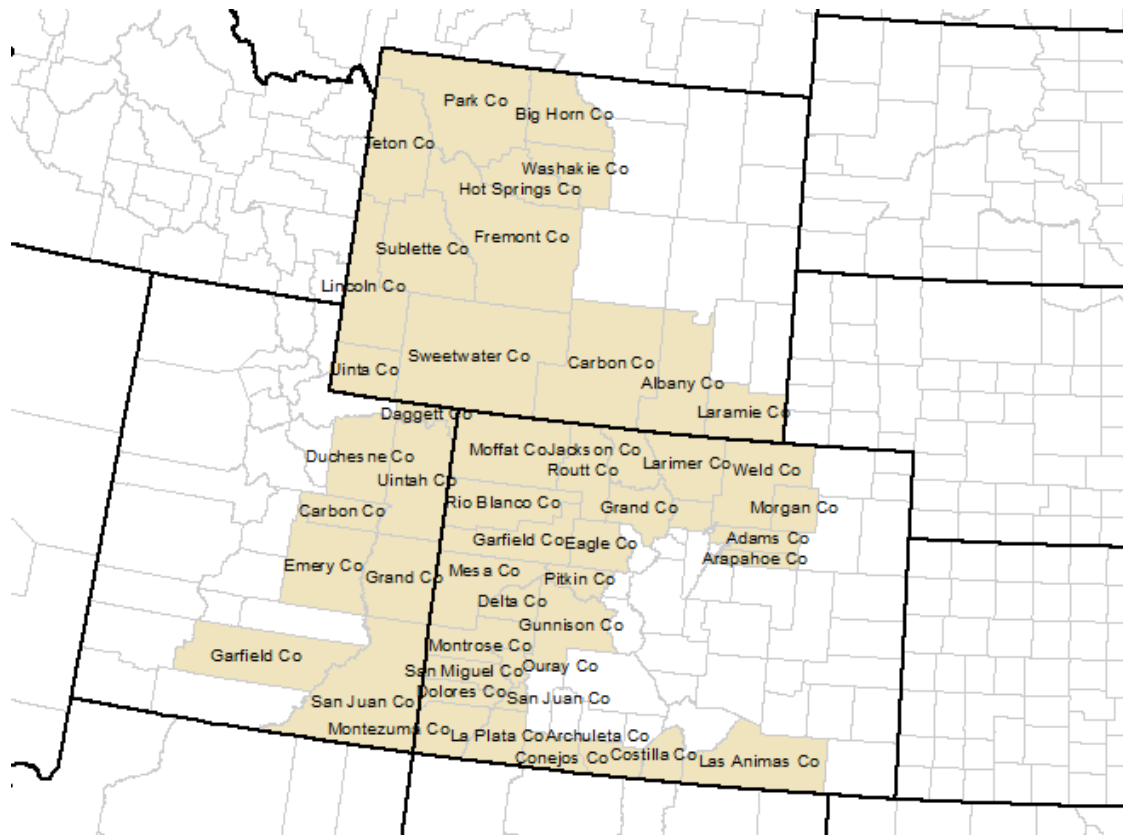


Figure 3-6. List of counties where the 3SAQS made targeted emission improvements to the EPA NEI.

The 3SAQS improvements over the EPA 2008, 2011 and 2020 National Emissions Inventory (NEI) for the CO/UT/WY counties include the following:

Utah

- Updated the 2007v5 spatial surrogates for land cover and building square footage with NLCD2006 and FEMA-HAZUS data
- Changed the ATV/ORV/Snowmobile surrogate assignment from rural land area to forest land
- Changed the livestock surrogate assignment from total agricultural land to pasture land
- Changed the fertilizer surrogate assignment from total agricultural land to crop land
- Created a state-specific, year 2011 monthly temporal profile for residential natural gas heating fuel use with Energy Information Administration data (Figure 3-7).
- Used point locations of rest areas and truck stops to allocation MOVES extended idling emissions to the modeling grid

Colorado

- Updated the 2007v5 spatial surrogates for land cover and building square footage with NLCD2006 and FEMA-HAZUS data
- Changed the ATV/ORV/Snowmobile surrogate assignment from rural land area to forest land
- Created CAFO spatial surrogates from data provided by CDPHE for livestock ammonia sources
- Changed the livestock surrogate assignment from total agricultural land to pasture land
- Changed the fertilizer surrogate assignment from total agricultural land to crop land
- Created a state-specific, year 2011 monthly temporal profile for residential natural gas heating fuel use with Energy Information Administration data (Figure 3-7).
- Developed 2008 vehicle miles traveled (VMT)-based spatial surrogates for on-road mobile sources. Figure 3-8 compares the U.S. Census year 2010 TIGER line roadway data with link-based VMT data from CO.
- Used point locations of rest areas and truck stops to allocation MOVES extended idling emissions to the modeling grid

Wyoming

- Updated the NEI08v2 spatial surrogates for land cover and building square footage with NLCD2006 and FEMA-HAZUS data
- Changed the ATV/ORV/Snowmobile surrogate assignment from rural land area to forest land
- Changed the livestock surrogate assignment from total agricultural land to pasture land
- Changed the fertilizer surrogate assignment from total agricultural land to crop land
- Created a state-specific, year 2011 monthly temporal profile for residential natural gas heating fuel use with Energy Information Administration data (Figure 3-7).
- Developed confined animal feeding operation (CAFO) spatial surrogates for livestock sources. The CAFOs locations data were provided by the state of Wyoming (Figure 3-9). The 3SAQS generated WY livestock surrogates for cattle, poultry, and swine.
- Used point locations of rest areas and truck stops to allocation MOVES extended idling emissions to the modeling grid

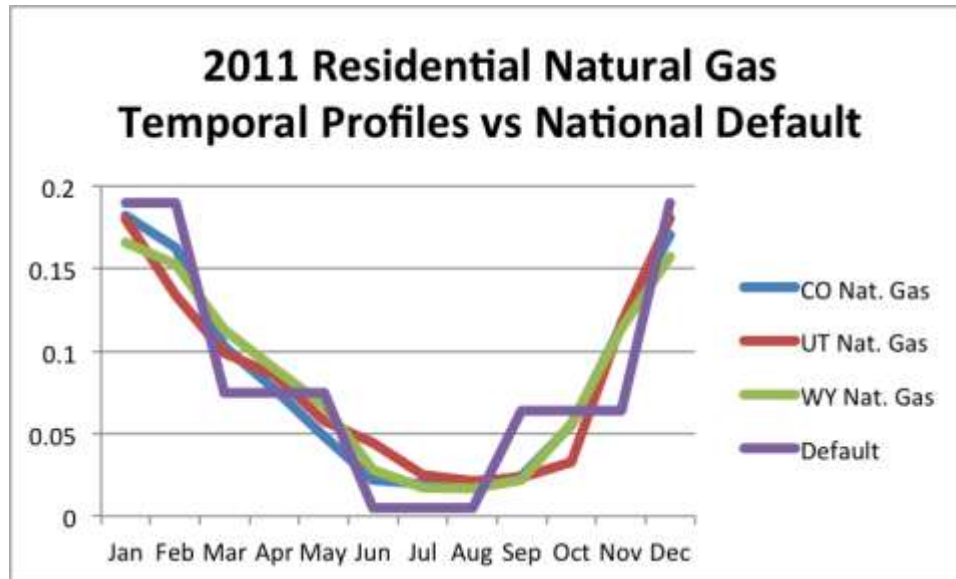


Figure 3-7. 3SAQS 2011 residential natural gas consumption monthly temporal profiles.

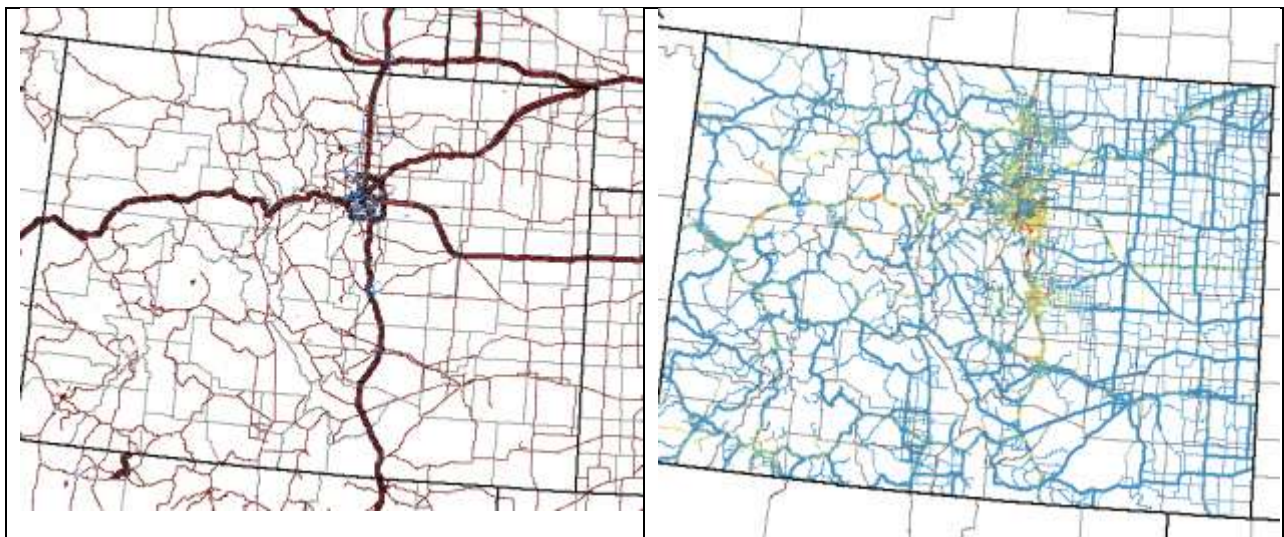


Figure 3-8. Colorado roadway spatial data improvement plots. Left: TIGER 2010 Shapefile of urban/rural primary/secondary roads. Right: CO 2008 VMT-based roadways.

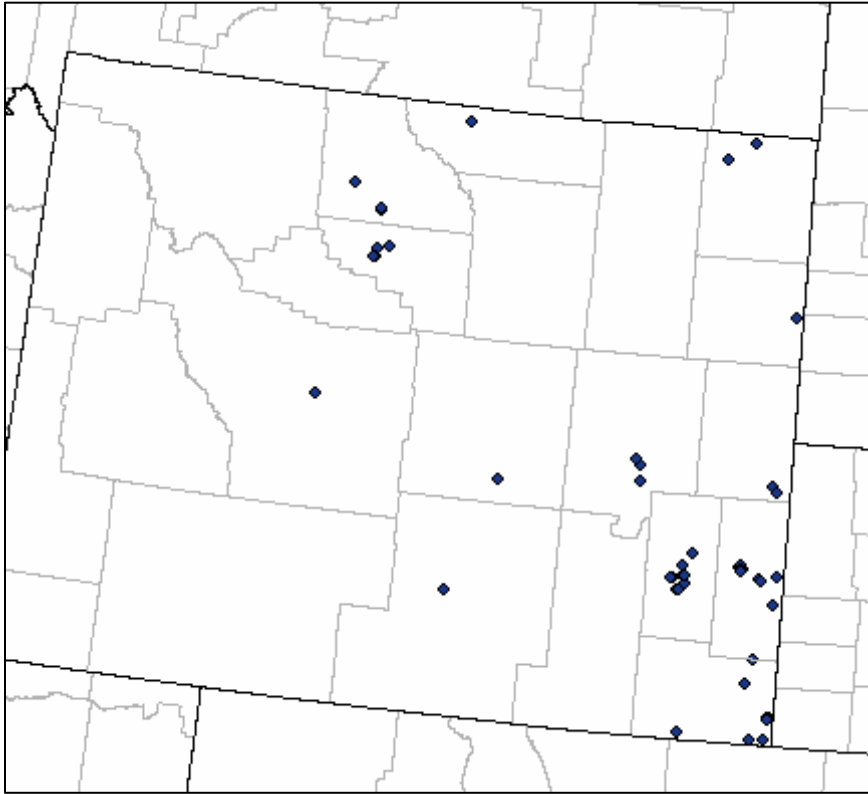


Figure 3-9. Wyoming CAFO locations.

3.6.2 Oil and Gas Future-Year Emissions Data

For oil and gas sources, ENVIRON developed emissions inventories for the western Colorado BLM planning areas as described in Section 3.1 and South San Juan basin, NM as described in Section 3.2.2. The oil and gas emissions for all other planning areas were provided by BLM as described in Section 3.2.

Oil and gas sources within 14 BLM planning areas, emissions were divided into existing and RFD (new) source categories to facilitate CAMx source apportionment processing. The RFD sources were further divided into oil and gas development on the BLM-authorized land (Federal) and other (non-Federal) lands. The South San Juan basin existing emissions were obtained from the WRAP Phase III midterm projection.

For processing oil and gas emissions, we developed ancillary data (spatial/temporal/chemical) specific to planning areas. The area-specific spatial allocation profiles were developed from the data provided by BLM and chemical speciation profiles were prepared from the gas composition available in the emission calculator. Table 3-3 provides a list of speciation and gridding profiles developed by planning areas. The conventional (CG) and CBM gas speciation profile are assigned to source categories associated with the respective well type. For spatial allocation, gridding profiles were developed for each well type (i.e., conventional, CBM) and land type (Federal, non-Federal) combination.

Table 3-3. Source of VOC speciation profile and spatial surrogates used for gridding oil and gas emissions in the 14 CO/NM BLM Planning Areas.

Source Region	Speciation Profiles	Gridding Profiles
Colorado		
Colorado River Valley, without Roan	CRV{CG}	CRVFO {CG}{Fed,non-Fed}
Grand Junction FO	GJ {CBM,CG,SG}	GJFO {CG,CBM}{Fed,non-Fed}
Kremmling FO	K {CBM,CG,CO}	KFO shapefile
Little Snake FO	LS {CG,CO}	CRVFO {CG}{Fed,non-Fed}
Roan Plateau	CRV{CG}	CRVFO_Roan_Plateau.
Tres Rios FO	TR {CBM,CG,CO,SHL}	TRFO {CG,CBM}{Fed,non-Fed}
Uncompahgre FO	U {CBM,CG}	UFO {CG,CBM}{Fed,non-Fed}
White River FO	WR {CG,CO}	WRVFO {CG}{Fed,non-Fed}
Pawnee National Grasslands	DJ{FLA ,VNT}	RGFO {CG}{Fed}
Royal Gorge FO Area1	DJ{FLA ,VNT}	RGFO {CG}{Fed,non-Fed}
Royal Gorge FO Area2	DJ{FLA ,VNT}	RGFO {CG}{Fed,non-Fed}
Royal Gorge FO Area3	DJ{FLA ,VNT}	RGFO {CG}{Fed,non-Fed}
Royal Gorge FO Area4	DJ{FLA ,VNT}	RGFO {CG}{Fed,non-Fed}
New Mexico		
Farmington FO	MAN{SG, SO}	Shapefile

3.6.3 Mining Future-Year Emissions Data

For mining sources, emissions were estimated for coal and uranium mines on Federal lands in the western Colorado BLM Planning Areas. The emissions for mines on Federal lands were estimated based on the CDPHE APEN database and available EISs and EAs. The mining emissions not on federal lands were obtained from the 2020 EPA/3SAQS inventory. EPA default chemical speciation profiles were used in the SMOKE emissions modeling for mining.

The estimated coal mining sources were consolidated with the 2020 EPA/3SAQS inventory to avoid potential double counting. The western Colorado uranium mining emissions were modeled as “area” and spatially allocated using spatial surrogates developed from the data provided by BLM in a shapefile format.

3.7 Emissions Modeling Results

Table 3-4 lists the total NO_x, VOC, SO₂ and PM_{2.5} emissions for the 20 Source Categories used in the CAMx 2021 High Development Scenario source apportionment simulation (see Section 4.1 and Table 4-1) plus three combined O&G source groups as well as total anthropogenic and all emissions within the 4 km CARMMS domain. These emissions were obtained from CAMx source apportionment diagnostic output file for each day of the annual simulation that were summed to obtain total annual emissions. The emissions in Table 3-4 differ from the ones presented earlier in Tables 3-1 and 3-2 in that they represent emissions after processing by SMOKE emissions model that performs spatial and temporal allocation and chemical speciation. Another important differences in the emissions presented in Table 3-4 from those in Tables 3-1 and 3-2 is that for the BLM Planning Areas (Numbers 1-14) the emissions are in Table 3-4 are

just for new O&G emissions on Federal lands, whereas Tables 3-1 and 3-2 Federal O&G emissions are for new and existing sources. For VOC, the differences in emissions between Tables 3-2 and Table 3-4 are even greater because SMOKE also does chemical speciation of the VOCs into the CB05 chemical mechanism that drops the unreactive portions of VOCs that do not participate in photochemistry.

For new Federal O&G within the 14 BLM Planning Areas and the 2021 High Development Scenario, the WRFO has the highest NO_x emissions (11,264 tons per year, TPY) followed by GJFO (7,293 TPY), FFO (3,321 TPY) and TRFO (2,665 TPY). Total 2021 O&G NO_x emissions in the 14 BLM Planning Areas is 178,447 TPY that is split 18 percent new Federal (32,566 TPY), 37 percent new non-Federal (65,713 TPY) and 45 percent existing O&G emissions (81,168 TPY). Outside of the 14 BLM Planning Areas, there is an additional 61,220 TPY O&G NO_x emissions for a total 2021 High Development Scenario O&G NO_x emissions across the entire 4 km CARMMS domain of 240,667 TPY that represents 34 percent of the total anthropogenic and 30 percent of the total (anthropogenic plus natural) NO_x emissions in the 4 km domain.

Total O&G VOC emissions in the 4 km CARMMS domain for the 2021 High Development Scenario are 835,785 TPY that represents 73 percent of the total anthropogenic and 39 percent of the total anthropogenic plus natural VOC emissions across the domain. Natural VOC emissions represent 46 percent of the annual VOC emissions across the 4 km CARMMS domain. Note that biogenic emissions are highly day-specific with higher emissions under warmer temperatures and higher light intensity. Thus, the contributions of biogenic VOC emissions to the total annual VOC emissions (46 percent) would be expected to be lower on cooler and higher on warmer days. Also note that the VOC emissions in Table 3-4 were obtained from the Carbon Bond chemical mechanism species that will be different than the VOC species input into the SMOKE emissions modeling system (for example, includes ethane and excludes nonreactive carbon in VOCs).

With one exception, SO₂ emissions from Federal O&G within the 14 BLM Planning Areas are fairly low (< 20 TPY). The exception is the WRFO Planning Area where the 904 TPY SO₂ emissions represent 95 percent of the 950 TPY SO₂ emissions from all 14 BLM Planning Areas combined in the 2021 High Development Scenario. A majority of the 2021 SO₂ emissions in the WRFO Planning Area come from two gas plants: the Enterprise Gas Proc – Meeker Gas Plant and the Williams Field – Willow Creek Gas Plant. These gas plant emissions were based on the CDPHE 2008 Air Pollution Emission Notice (APEN) database grown to 2021 using the change in gas production between 2008 and 2021 for the 2021 High, Low and Medium Development Scenarios. Total O&G SO₂ emissions across the CARMMS domain is 6,071 TPY that is primarily (75 percent) due to O&G from outside of the 14 BLM Planning Areas, these areas in the 4 km CARMMS domain outside of the 14 BLM Planning Areas includes the Uinta Basin where sour gas reserves occur.

Total PM_{2.5} emissions from O&G in the 14 BLM Planning Areas and the 2021 High Development Scenario is 7,849 TPY of which over half (58 percent) is due to new non-Federal O&G and the rest approximately split equally between new Federal and existing O&G. Mining within the 14 BLM Planning Areas contributes 6,957 TPY. By far the largest contribution of primary PM_{2.5} emissions is the other (non O&G and mining) anthropogenic emissions category that

contributes 74 percent of the region-wide total with natural emissions (mostly due to wildfires) contributing most of the rest (23 percent).

Table 3-5a is like Table 3-4 only for the 2021 Low Development Scenario, with the percent reductions of emissions between the Low and High development Scenarios shown in Table 3-5b. The total new Federal O&G NO_x emissions across the 14 BLM Planning Areas for the low scenario (8,385 TPY) is 74% lower than the high scenario (32,566 TPY). Similar reductions are seen for the other species (-63 to -83 percent). The annual emissions for the 2021 Medium Development Scenario are shown in Table 3-6a with the percent reduction from the 2021 High Development Scenario given in Table 3-6b. Total O&G NO_x emissions across the 14 BLM Planning Areas for the 2021 Medium Development Scenario is 27,071 TPY that is -17% lower than the 201 High Development Scenario (Table 3-6b). Similarly, 2021 Medium Development Scenario O&G VOC emissions across the 14 BLM Planning Areas are 35% lower than the 2021 High Development Scenario.

Table 3-4. Total emissions (tons per year) for each Source Category (see Table 4-1) and combinations of Source Categories for the 2021 High Development Scenario from the CAMx source apportionment diagnostic output files after processing by SMOKE.

CARMMS 2021 High Development Scenario (tpy)						
Number	Group	NO_x	VOC	SO₂	PM_{2.5}	PM₁₀
19	Natural (Biogenics + Fires)	113,165	992,560	1,132	79,453	574,255
1	LSFO	2,007	4,648	13	73	170
2	WRFO	11,264	27,258	904	597	1,368
3	CRVFO	1,311	6,076	2	71	250
4	RPPA	1,245	2,739	1	48	135
5	GJFO	7,293	18,108	15	310	1,496
6	UFO	586	870	1	35	140
7	TRFO	2,665	1,715	2	125	855
8	KFO	177	412	0	10	50
9	RGFO #1	303	875	1	29	225
10	PGPA	930	2,682	3	90	689
11	RGFO #2	1,151	1,526	1	22	58
12	RGFO #3	224	77	0	3	16
13	RGFO #4	90	944	0	16	134
14	FFO	3,321	8,747	5	314	1,824
15	New O&G from non-Fed BLM PAs	65,713	228,655	297	4,548	30,790
16	Existing O&G from BLM PAs	81,169	228,749	252	1,558	2,838
17	Mining from BLM PAs	686	46	8	6,957	6,977
18	All O&G outside 14 BLM PAs	61,220	301,705	4,572	2,680	2,822
20	Remaining anthro emissions	459,907	312,498	95,720	242,828	1,400,504
	14 BLM PAs Fed O&G	32,566	76,676	950	1,744	7,409
	14 PAs Total O&G	179,447	534,080	1,499	7,849	41,038
	Total O&G	240,667	835,785	6,071	10,530	43,859
	Total Anthropogenic	701,260	1,148,329	101,799	260,315	1,451,340
	Total All Emissions	814,425	2,140,889	102,931	339,768	2,025,594

Table 3-5a. Total emissions (tons per year) for each Source Category (see Table 4-1) and combinations of Source Categories for the 2021 Low Development Scenario from the CAMx source apportionment diagnostic output files after processing by SMOKE.

CARMMS 2021 Low Development Scenario (tpy)						
Number	Group	NO_x	VOC	SO₂	PM_{2.5}	PM₁₀
19	Natural (Biogenics + Fires)	113,165	992,560	1,132	79,453	574,255
1	LSFO	275	638	2	10	23
2	WRFO	1,861	4,502	149	99	226
3	CRVFO	844	3,916	1	46	161
4	RPPA	656	1,552	1	26	70
5	GJFO	425	965	1	20	72
6	UFO	150	270	0	10	45
7	TRFO	326	227	0	16	89
8	KFO	21	34	0	1	5
9	RGFO #1	61	262	0	5	42
10	PGPA	188	804	1	17	129
11	RGFO #2	104	191	0	2	6
12	RGFO #3	141	51	0	2	11
13	RGFO #4	14	135	0	2	20
14	FFO	3,321	8,747	5	314	1,824
15	New O&G from non-Fed BLM PAs	31,247	104,163	113	2,057	13,769
16	Existing O&G from BLM PAs	81,169	228,749	252	1,558	2,838
17	Mining from BLM PAs	686	46	8	6,957	6,977
18	All O&G outside 14 BLM PAs	61,220	301,705	4,572	2,680	2,822
20	Remaining anthro emissions	459,907	312,498	95,720	242,828	1,400,504
	14 BLM PAs Fed O&G	8,385	22,294	161	570	2,723
	14 PAs Total O&G	120,801	355,207	527	4,185	19,331
	Total O&G	182,021	656,912	5,099	6,865	22,152
	Total Anthropogenic	642,614	969,456	100,827	256,651	1,429,633
	Total All Emissions	755,779	1,962,016	101,958	336,104	2,003,888

Table 3-5b. Percent difference in 2021 High and Low Development Scenario emissions (High – Low) for each Source Category (see Table 4-1) and combinations of Source Categories from the CAMx source apportionment diagnostic output after processing by SMOKE.

CARMMS 2021 Low Scenario Percent Change from High Scenario (%)						
Number	Group	NO_x	VOC	SO₂	PM_{2.5}	PM₁₀
19	Natural (Biogenics + Fires)	0.0%	0.0%	0.0%	0.0%	0.0%
1	LSFO	-86.3%	-86.3%	-86.4%	-86.3%	-86.4%
2	WRFO	-83.5%	-83.5%	-83.5%	-83.5%	-83.5%
3	CRVFO	-35.6%	-35.5%	-35.7%	-35.2%	-35.5%
4	RPPA	-47.3%	-43.3%	-46.8%	-46.3%	-48.2%
5	GJFO	-94.2%	-94.7%	-94.1%	-93.6%	-95.2%
6	UFO	-74.5%	-69.0%	-76.5%	-70.6%	-67.7%
7	TRFO	-87.8%	-86.8%	-83.8%	-87.1%	-89.6%
8	KFO	-88.2%	-91.7%	-88.8%	-89.2%	-89.8%
9	RGFO #1	-79.8%	-70.0%	-81.9%	-81.6%	-81.3%
10	PGPA	-79.8%	-70.0%	-81.9%	-81.2%	-81.2%
11	RGFO #2	-91.0%	-87.5%	-90.8%	-90.5%	-89.3%
12	RGFO #3	-37.0%	-34.0%	-37.5%	-33.0%	-31.0%
13	RGFO #4	-85.0%	-85.7%	-85.0%	-85.4%	-85.4%
14	FFO	0.0%	0.0%	0.0%	0.0%	0.0%
15	New O&G from non-Fed BLM PAs	-52.4%	-54.4%	-61.8%	-54.8%	-55.3%
16	Existing O&G from BLM PAs	0.0%	0.0%	0.0%	0.0%	0.0%
17	Mining from BLM PAs	0.0%	0.0%	0.0%	0.0%	0.0%
18	All O&G outside 14 BLM PAs	0.0%	0.0%	0.0%	0.0%	0.0%
20	Remaining anthro emissions	0.0%	0.0%	0.0%	0.0%	0.0%
	14 BLM PAs Fed O&G	-74.3%	-70.9%	-83.1%	-67.3%	-63.2%
	14 PAs Total O&G	-32.7%	-33.5%	-64.9%	-46.7%	-52.9%
	Total O&G	-24.4%	-21.4%	-16.0%	-34.8%	-49.5%
	Total Anthropogenic	-8.4%	-15.6%	-1.0%	-1.4%	-1.5%
	Total All Emissions	-7.2%	-8.4%	-0.9%	-1.1%	-1.1%

Table 3-6a. Total emissions (tons per year) for each Source Category (see Table 4-1) and combinations of Source Categories for the 2021 Medium Development Scenario from the CAMx source apportionment diagnostic output files after processing by SMOKE.

CARMMS 2021 Medium Development Scenario (tpy)						
Number	Group	NO _x	VOC	SO ₂	PM _{2.5}	PM ₁₀
19	Natural (Biogenics + Fires)	113,165	992,560	1,132	79,453	574,255
1	LSFO	1,779	3,633	13	58	98
2	WRFO	9,809	18,803	904	500	810
3	CRVFO	1,060	3,253	2	51	123
4	RPPA	1,023	1,848	1	35	70
5	GJFO	6,149	8,345	15	196	673
6	UFO	460	733	1	24	66
7	TRFO	2,263	1,253	2	65	361
8	KFO	137	210	0	6	23
9	RGFO #1	193	679	1	10	52
10	PGPA	593	2,081	3	29	158
11	RGFO #2	846	1,468	1	15	25
12	RGFO #3	156	54	0	2	5
13	RGFO #4	51	679	0	5	30
14	FFO	2,552	6,808	4	185	745
15	New O&G from non-Fed BLM PAs	64,849	227,796	297	4,517	30,722
16	Existing O&G from BLM PAs	81,169	228,749	252	1,558	2,838
17	Mining from BLM PAs	686	46	8	6,957	6,977
18	All O&G outside 14 BLM PAs	61,220	301,705	4,572	2,680	2,822
20	Remaining anthro emissions	459,907	312,498	95,720	242,828	1,400,504
	14 BLM PAs Fed O&G	27,071	49,849	947	1,180	3,239
	14 PAs Total O&G	173,089	506,394	1,496	7,254	36,800
	Total O&G	234,309	808,100	6,068	9,935	39,621
	Total Anthropogenic	694,902	1,120,643	101,796	259,720	1,447,102
	Total All Emissions	808,067	2,113,203	102,928	339,173	2,021,356

Table 3-6b. Percent difference in 2021 High and Medium Development Scenario emissions (High – Medium) for each Source Category (see Table 4-1) and combinations of Source Categories from the CAMx source apportionment diagnostic output files after processing by SMOKE.

CARMMS 2021 Medium Scenario Percent Change from High Scenario (%)						
Number	Group	NO _x	VOC	SO ₂	PM _{2.5}	PM ₁₀
19	Natural (Biogenics + Fires)	0.0%	0.0%	0.0%	0.0%	0.0%
1	LSFO	-11.3%	-21.8%	-1.4%	-20.7%	-42.7%
2	WRFO	-12.9%	-31.0%	0.0%	-16.4%	-40.8%
3	CRVFO	-19.1%	-46.5%	-0.4%	-27.9%	-50.6%
4	RPPA	-17.9%	-32.5%	-0.3%	-26.9%	-48.1%
5	GJFO	-15.7%	-53.9%	-0.6%	-36.8%	-55.0%
6	UFO	-21.5%	-15.7%	-5.2%	-32.4%	-52.5%
7	TRFO	-15.1%	-26.9%	-4.1%	-47.9%	-57.8%
8	KFO	-22.5%	-48.9%	-7.2%	-40.1%	-55.3%
9	RGFO #1	-36.2%	-22.4%	-20.6%	-67.0%	-77.0%
10	PGPA	-36.2%	-22.4%	-20.6%	-67.2%	-77.0%
11	RGFO #2	-26.5%	-3.8%	-24.8%	-33.2%	-56.2%
12	RGFO #3	-30.2%	-29.8%	-28.3%	-50.5%	-68.3%
13	RGFO #4	-43.5%	-28.0%	-1.0%	-71.0%	-77.4%
14	FFO	-23.1%	-22.2%	-21.4%	-41.0%	-59.2%
15	New O&G from non-Fed BLM PAs	-1.3%	-0.4%	-0.1%	-0.7%	-0.2%
16	Existing O&G from BLM PAs	0.0%	0.0%	0.0%	0.0%	0.0%
17	Mining from BLM PAs	0.0%	0.0%	0.0%	0.0%	0.0%
18	All O&G outside 14 BLM PAs	0.0%	0.0%	0.0%	0.0%	0.0%
20	Remaining anthro emissions	0.0%	0.0%	0.0%	0.0%	0.0%
	14 BLM PAs Fed O&G	-16.9%	-35.0%	-0.3%	-32.3%	-56.3%
	14 PAs Total O&G	-3.5%	-5.2%	-0.2%	-7.6%	-10.3%
	Total O&G	-2.6%	-3.3%	-0.1%	-5.7%	-9.7%
	Total Anthropogenic	-0.9%	-2.4%	0.0%	-0.2%	-0.3%
	Total All Emissions	-0.8%	-1.3%	0.0%	-0.2%	-0.2%

Figure 3-10 displays spatial maps of NO_x, VOC and PM_{2.5} emissions across the 4 km CARMMS domain by different source types for the 2021 High Development Scenario. The spatial maps for the Low and Medium Development Scenarios have the same locations as the High Development Scenario just with lower intensity. Figure 3-10a displays the total new Federal and new non-Federal O&G emissions across the 14 CO/NM BLM Planning Areas that shows a mixture of Federal and non-Federal O&G emissions in the western Colorado Planning Areas. Most of the new O&G emissions in the eastern Colorado Planning Areas (e.g., Weld County) are due to non-Federal O&G, except for the development within the Pawnee Grassland Planning Area. The differences in the new Federal and non-Federal O&G emissions for the Mancos Shale

Development area in northern New Mexico reflects the assumption that new O&G was split 70 percent Federal and 30 percent non-Federal.

Figure 3-10b top panel displays the spatial distribution of emissions that combines the existing O&G within the 14 CO/NM BLM Planning Areas with the remainder O&G (new Federal and non-Federal plus existing) within the 4 km CARMMS domain but outside of the 14 CO/NM BLM Planning Areas. In addition to the familiar Basins within the 14 CO/NM Planning Areas (Denver-Julesburg, Piceance and North and South San Juan), the Uinta Basin is clearly evident along with O&G emissions in southwest Wyoming and in the Texas panhandle. Mining within the Colorado BLM Planning Areas consist of mainly isolated grid cells that can have very high PM_{2.5} emissions (Figure 3-10b, bottom panel). Figure 3-10c displays the other (remainder) anthropogenic emissions and natural emissions. Roadways and the major urban areas of Denver, Salt Lake City, Colorado Springs and Albuquerque are clearly evident in the other anthropogenic emissions NO_x and VOC maps. Whereas the spatial maps of other anthropogenic PM_{2.5} emissions is more reflective of agricultural sources. Natural VOC emissions are dominated by forested areas, whereas the natural NO_x emissions are higher in agricultural areas and the locations of fires in 2008.

3.7.1 Mining PM Speciation Issues

The EPA default PM speciation profiles as provided with the SMOKE emissions modeling system were used to speciate PM emissions for mining sources. These PM speciation profiles convert total PM_{2.5} emissions into particulate SO₄, NO₃, NH₄, EC, OA and OPM_{2.5} (other PM_{2.5}) for the PGM modeling. In analyzing the AQ and AQRV impacts associated with mining on Federal lands in the CARMMS 2021 modeling results, we noticed sulfur deposition impacts and visibility impairment impacts due to SO₄ that were higher than expected given the low SO₂ emissions from mining for the 2021 emission scenarios (8 TPY, see Tables 3-4 through 3-6). These higher than expected sulfur impacts from mining were due to primary SO₄ emissions. Of the 6,957 TPY PM_{2.5} emissions from mining (Table 3-4), 874 TPY (12.5%) is due to primary SO₄ emissions.

Table 3-7 lists the mining source categories and emissions by Source Classification Code (SCC) and the PM speciation profile code used in the SMOKE modeling system that is used to speciate the mining PM emissions using a cross-reference with the SCC number. SMOKE speciates most of the mining PM emissions using the 92047 PM speciation profile that is for “Mineral Products – Avg – Simplified.” Table 3-8 lists the PM_{2.5} speciation profiles for the three profiles used to speciate the mining emissions in SMOKE. For the dominant 92047 PM profile for mining, 14.1% of the PM_{2.5} emissions are speciated as primary SO₄. The reference for the 92047 PM speciation profile in the SPECIATE database is “Shareef, G.S. Engineering Judgment, Radian Corporation. September 1987.” In our search we could not find this reference.

For some types of above ground mining that uses blasting, higher sulfur emissions may be expected. However, in Colorado most of the mining is underground that would not include blasting so would be expected to have lower sulfur emissions, which is reflected in the low mining SO₂ emissions. Thus, it appears that mining primary SO₄ emissions are overstated in the CARMMS 2021 modeling, which would result in overstated sulfur deposition and visibility impacts associated with mining. This issue will be discussed with EPA so that the SMOKE emissions modeling system can be updated in the future.

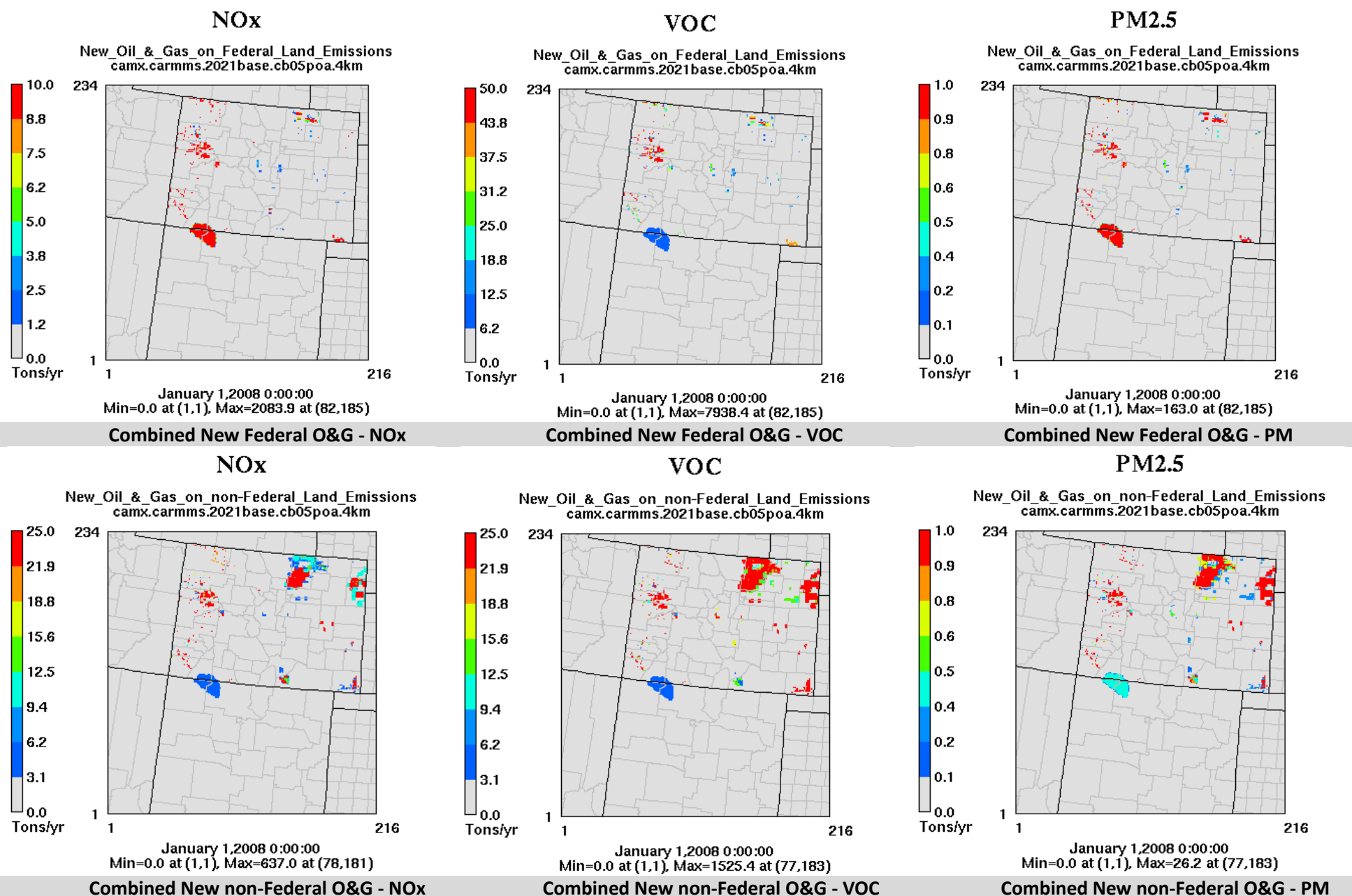


Figure 3-10a. Spatial distribution of Federal (top) and non-Federal oil and gas NO_x, VOC and PM_{2.5} emissions (tons per year) for the 14 BLM Planning Areas and the 2021 High Development Scenario.

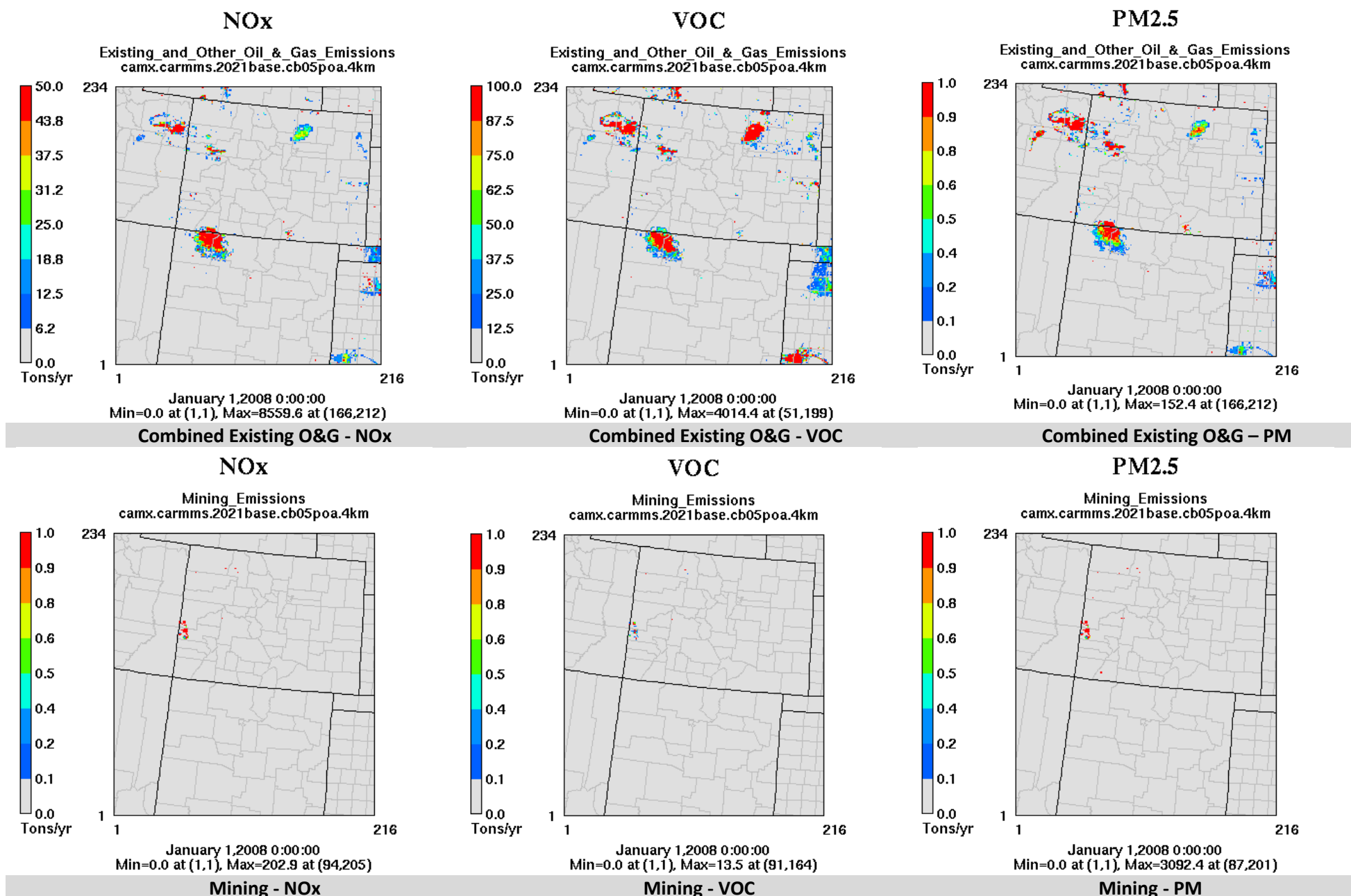


Figure 3-10b. Spatial distribution of Existing oil and gas (top) and mining on Federal lands NO_x, VOC and PM_{2.5} emissions (tons per year) for the 14 BLM Planning Areas and the 2021 High Development Scenario.

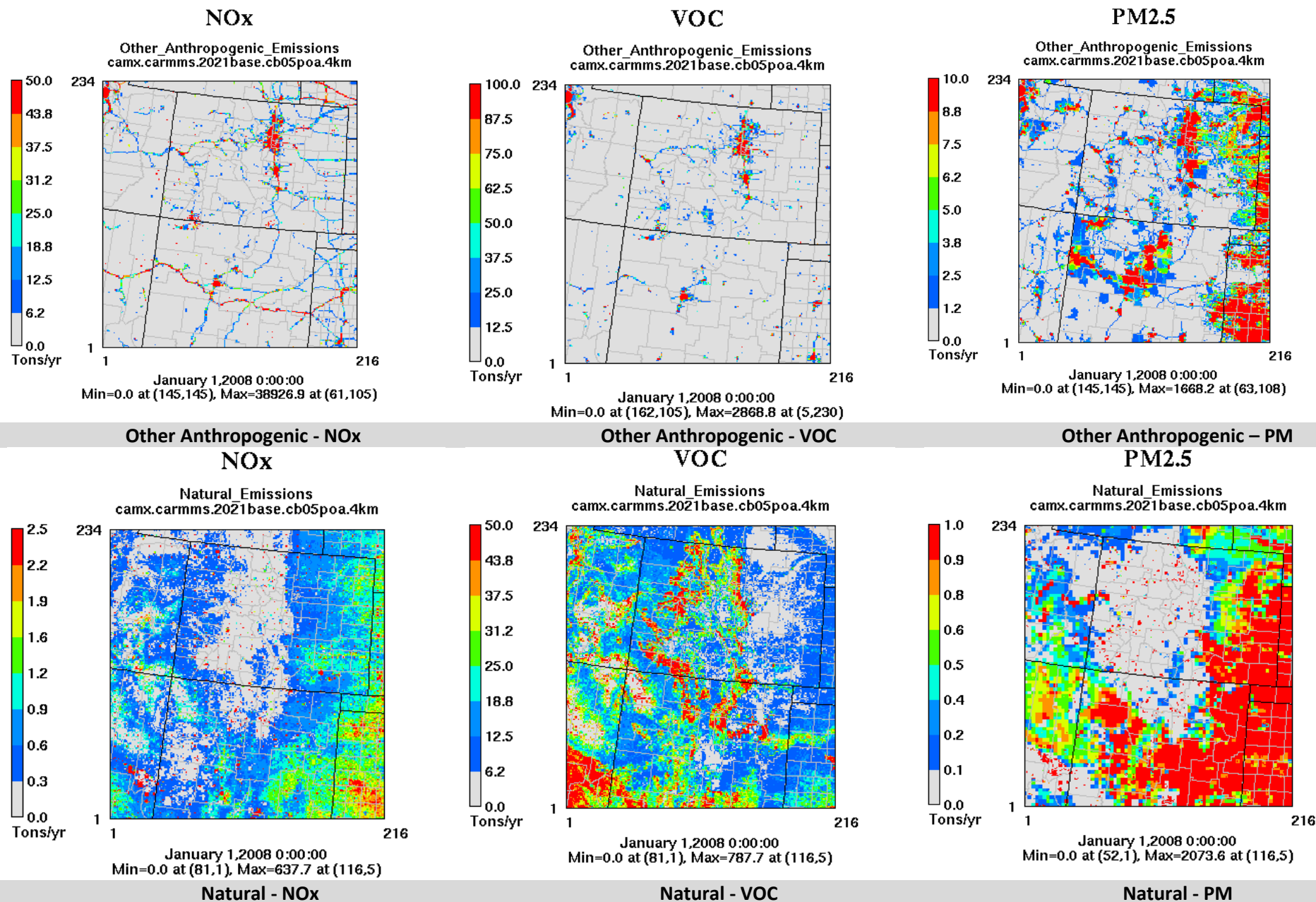


Figure 3-10c. Spatial distribution of other anthropogenic (top) and natural (biogenic, fires, lightning, sea salt and windblown dust) NO_x, VOC and PM_{2.5} emissions (tons per year) for the 14 BLM Planning Areas and the 2021 High Development Scenario.

Table 3-7. SCC number and description, PM_{2.5} speciation profile code and name, and PM emissions for 95% of the mining emissions on Federal lands used in the CARMMS 2021 modeling

SCC	SCC Description	Profile	Profile name	PM2.5 (tpy)
30501099	Coal Mining, Cleaning & Material Handling /Other Not Classified	92047	Mineral Products - Avg - Simplified	1,717
30501022	Coal Mining, Cleaning & Material Handling /Drilling/Blasting	92047	Mineral Products - Avg - Simplified	1,460
30501011	Coal Mining, Cleaning & Material Handling /Coal Transfer	92047	Mineral Products - Avg - Simplified	1,449
30501015	Coal Mining, Cleaning & Material Handling /Loading	92047	Mineral Products - Avg - Simplified	457
30501049	Coal Mining, Cleaning & Material Handling /Wind Erosion: Exposed Areas	92022	Crustal Material - Simplified	403
30501038	Coal Mining, Cleaning & Material Handling /Truck Loading: Coal	92047	Mineral Products - Avg - Simplified	333
30501043	Coal Mining, Cleaning & Material Handling /Open Storage Pile: Coal	92047	Mineral Products - Avg - Simplified	113
30501024	Coal Mining, Cleaning & Material Handling /Hauling	92047	Mineral Products - Avg - Simplified	105
30504010	Mining & Quarrying Nonmetallic Minerals /Underground Ventilation	92073	Sand & Gravel - Simplified	72
30501040	Coal Mining, Cleaning & Material Handling /Truck Unloading: End Dump – Coal	92047	Mineral Products - Avg - Simplified	68
30501046	Coal Mining, Cleaning & Material Handling /Bulldozing: Coal	92047	Mineral Products - Avg - Simplified	67
30501009	Coal Mining, Cleaning & Material Handling /Raw Coal Storage	92047	Mineral Products - Avg - Simplified	61

Table 3-8. PM_{2.5} speciation profiles used to speciate the mining PM emissions.

Profile	Pol	Species	Fraction
Mineral Products - Avg - Simplified			
92047	PM2_5	POA	7.4%
92047	PM2_5	PEC	1.5%
92047	PM2_5	PNO3	0.3%
92047	PM2_5	PSO4	14.1%
92047	PM2_5	PMFINE	76.8%
Crustal Material - Simplified			
92022	PM2_5	POA	7.5%
92022	PM2_5	PEC	0.2%
92022	PM2_5	PNO3	0.1%
92022	PM2_5	PSO4	0.2%
92022	PM2_5	PMFINE	92.0%
Sand & Gravel - Simplified			
92073	PM2_5	POA	0.0%
92073	PM2_5	PEC	0.0%
92073	PM2_5	PNO3	0.1%
92073	PM2_5	PSO4	0.3%
92073	PM2_5	PMFINE	99.7%

4.0 FUTURE YEAR MODELING APPROACH

The CAMx source apportionment tool was used to obtain separate contributions of BLM authorized oil and gas development on Federal lands within 13 Colorado BLM Planning Areas plus the Mancos Shale Development area in northwestern New Mexico. This final report addresses the contributions to air quality (AQ) and air quality related value (AQRV) impacts associated with the 2021 High, Low and Medium Development Scenarios. The following sections describe how the CARMMS 2021 CAMx source apportionment modeling was conducted for the three scenarios and analyzed with the results presented in Chapter 5.

4.1 CARMMS Source Apportionment Modeling Approach

The CAMx Anthropogenic Precursor Culpability Assessment (APCA) version of the Ozone Source Apportionment Technology (OSAT) and the Particulate Source Apportionment Technology (PSAT) were used to obtain separate AQ and AQRV contributions due to BLM-authorized new oil and gas development on Federal lands for each of the 13 Colorado BLM Planning Areas and the Mancos Shale O&G development area within the New Mexico BLM Farmington Field Office (NMFFO) Planning Area (i.e., the 14 BLM Planning Areas). Separate source apportionment contributions from new oil and gas emissions on non-Federal lands and existing oil and gas within the combined 14 BLM Planning Areas was also obtained. Separate source apportionment of AQ/AQRV impacts associated with the 10 mines located within Colorado BLM Planning Areas discussed at the end of Section 3.1.5 was also obtained. Separate source apportionment contributions was also obtained for oil and gas emissions within the 4 km CARMMS domain outside of the 14 BLM Planning Areas, remainder anthropogenic emissions and natural emissions (i.e., biogenic sources, fires, lightning, windblown dust and sea salt).

4.1.1 Overview of Source Apportionment Tools

The CAMx OSAT/APCA ozone and PSAT PM source apportionment tools use reactive tracers that are released from each Source Group for which contributions are desired. These reactive tracers operate in parallel to the host photochemical grid model accessing the model's transport, dispersion, chemistry and deposition algorithms. For example, the OSAT/APCA ozone source apportionment tools represents each Source Group's ozone contributions using four reactive tracers that represent the Source Groups VOC emissions (V), NO_x emissions (N) and ozone attributed to the Source Group that is formed under more VOC-limited (O3V) and NO_x-limited (O3N) conditions. At each time step and in each grid cell, ozone formed is allocated to the Source Groups based on the Source Groups relative contribution of VOC or more NO_x emissions to the total VOC or NO_x concentrations after determination of whether ozone formation is more VOC-limited or more NO_x-limited. The APCA ozone source apportionment tool differs from OSAT in that it recognizes that some precursor emissions are not controllable so redirects ozone formed from the uncontrollable to the controllable Source Group. For example, when ozone is formed under VOC-limited conditions due to the interaction between biogenic VOC and anthropogenic NO_x emissions, a case OSAT would assign the ozone formed to the biogenic emissions Source Group, APCA redirects the ozone formed to the anthropogenic emissions Source Group recognizing that biogenic VOC emissions are not controllable and without the anthropogenic NO_x the ozone would not have been generated. In a CAMx APCA source apportionment run, the first Source Category specified in the run is

assumed to be the uncontrollable Source Group (typically natural emissions) and ozone will only be allocated to natural emissions when it is due to natural VOC and NO_x emissions interacting with each other (e.g., ozone formed due to reactions between biogenic VOC and biogenic NO_x). For the CARMMS modeling, the natural emissions Source Group included biogenic, fires (wildfires, prescribed burns and agricultural burning), lightning, windblown dust and sea salt emissions. Although one could argue that emissions from prescribed burns and agricultural burning are not natural, emissions from wildfires dominate the fire emissions especially within the CARMMS 4 km domain.

For the CAMx PSAT PM source apportionment tool there are several families of PM source apportionment tracers that can be run separately or together that track the different components of PM. Each of these families has a different number of reactive tracers to track the pathway from the PM precursor emissions to the ultimate PM compounds. The five different families of PSAT source apportionment are as follows (number of tracers in parenthesis): Sulfate-SO₄ (2); Nitrate/Ammonium-NO₃/NH₄ (7); Primary PM (6); Secondary Organic Aerosol-SOA (20) and Mercury-Hg (3). For CARMMS, we used the SO₄, NO₃/NH₄ and Primary PM PSAT families of tracers so that 15 total reactive tracers are needed to track PM contribution for each Source Group. The Hg PSAT family was not used because mercury is not a focus of CARMMS and O&G sources have negligible Hg emissions. There are five SOA precursors treated in CAMx: toluene and xylene (aromatics), isoprene, terpene and sesquiterpene with biogenic sources contributing a majority of the SOA. O&G VOC emissions are dominated by light VOCs that do not form any SOA. We examined the speciation of the O&G emissions and found the five VOC species that are SOA precursors account for approximately 0.1 percent of the O&G VOC emissions. Thus, O&G emission VOCs would have a negligible contribution to SOA so the SOA family of PSAT source apportionment tracers was not used. The CARMMS annual source apportionment runs take over a month to complete and use of the SOA PSAT family would have more than doubled the number of tracers.

Thus, SOA is not included in the PM_{2.5} and visibility impacts associated with Source Groups A through V that are based on the PSAT source apportionment modeling results. But SOA is included in the PM_{2.5} and visibility impacts of Source Groups W and X that represents total emissions from the 2021 and 2008 emission scenarios.

4.1.2 CARMMS Source Apportionment Configuration

The APCA version of the OSAT and the SO₄, NO₃/NH₄ and Primary PM (i.e., no SOA) families of PSAT source apportionment was used to track the AQ/AQRV contributions of new O&G development on Federal lands in 14 separate BLM Planning Areas for the 2021 High, Low and Medium Development Scenarios using the CARMMS 2008 4 km modeling platform. The 14 BLM Planning Areas where separate AQ/AQRV impacts due to new O&G development on Federal lands were simulated are shown in Figure 4-1. In total, the 2021 CAMx source apportionment modeling tracked AQ/AQRV contributions for 20 separate Source Categories in the order listed in Table 4-1. Because the APCA version of OSAT is being used, the first Source Category has to be natural emissions. The 2nd through 15th Source Categories correspond to new O&G emissions on Federal lands within the 13 Colorado BLM planning areas and the Mancos Shale development area within the BLM NMFFO lands (the 14 BLM Planning Areas).

The 16th Source Category is the combined emissions from all new O&G within the 14 BLM Planning Areas on non-Federal lands. The 17th and 18th Source Categories are, respectively, existing O&G within the 14 BLM Planning Areas and mining on Federal lands within the 14 BLM Planning Areas⁶⁷. The 19th Source Category is all O&G emissions (existing, new Federal and new non-Federal) outside of the 14 BLM Planning Areas (i.e., the yellow area in Figure 4-1). And the final (20th) Source Category is remaining anthropogenic emissions (e.g., point, mobile and area sources that are not O&G everywhere or mining on Federal lands within the 14 BLM Planning Areas).

Table 4-1. Ordering of the 20 Source Categories used in the CAMx 2021 source apportionment modeling.

1	Natural emissions (combined biogenic, fires, lightning, sea salt and WBD).
2	Little Snake FO
3	White River FO
4	Colorado River Valley FO (CRVFO)
5	Roan Plateau Planning area portion of CRVFO
6	Grand Junction FO
7	Uncompahgre FO
8	Tres Rios FO
9	Kremmling FO
10	Royal Gorge FO Area#1 (RGFO#1) -- North
11	Pawnee Grasslands portion of RGFO#1
12	RGFO#2 – West-Central/South
13	RGFO#3 – South
14	RGFO#4 – East-Central
15	New Mexico Farmington Field Office
16	Combined New O&G from non-Federal lands within the 14 BLM Planning Areas
17	Combined Existing O&G from 14 BLM Planning Areas
18	Mining from 14 BLM Planning Areas
19	All O&G (existing and new on Federal and non-Federal lands) in 4 km domain outside of the 14 BLM Planning Areas (see yellow region in Figure 1)
20	Remaining anthropogenic emissions (on-road and non-road mobile, point and area sources everywhere in 4 km domain)

⁶⁷ There were no mining emissions within the northern New Mexico Mancos Shale development area.

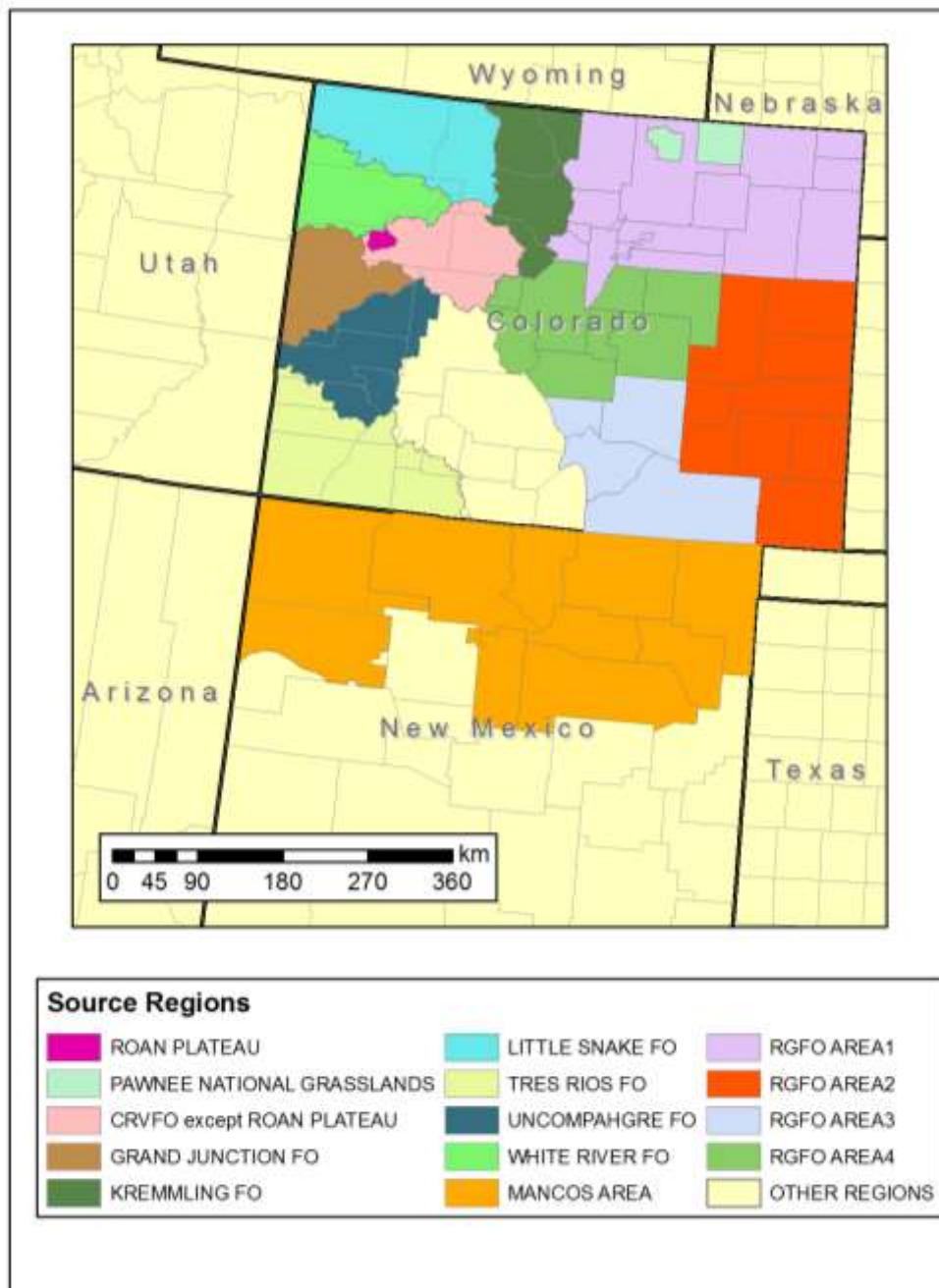


Figure 4-1. 13 Colorado and New Mexico BLM planning areas (the 14 BLM Planning Areas) where separate contributions of new O&G development on Federal lands was obtain for 2021 source apportionment modeling.

4.2 Post-Processing of the CAMx 2021 Source Apportionment Modeling Results

The CAMx 2021 total concentrations results were post-processed for comparisons to the applicable ambient air quality standards as listed in Table 4-3. With the exception of ozone, where results will be reported in concentration units of part per billion by volume (ppb), all concentrations will be reported in units of micrograms per cubic meter ($\mu\text{g}/\text{m}^3$). Gas-phase species were converted from parts per million (ppm) to $\mu\text{g}/\text{m}^3$ using the conversion factor recommended in the Colorado Department of Health and Environment (CDPHE) air permit modeling guidance⁶⁸. The incremental AQ and AQRV impacts due to each of the 24 Source Groups listed in Table 4-2 are reported. These 24 Source Groups are labeled A through X consist of the following sources:

- (A - N) New Federal O&G from each of the 14 BLM Planning Areas as shown in Figure 4-1 and listed as Source Categories No. 2 through 15 in Table 4-1.
- (O) Total Federal O&G from the CRVFO that combines the Roan Plateau and non-Roan Plateau portions of the CRVFO.
- (P) Total Federal O&G from the RGFO that combines the four RGFO subregions plus the Pawnee Grassland portion of the RGFO.
- (Q) Mining on Federal land within the 13 Colorado BLM Planning Areas.
- (R) Combined O&G and mining development on Federal lands within all of the 13 Colorado BLM Planning Areas.
- (S) Combined new O&G and mining development on Federal lands and new O&G development non-Federal lands within the 13 Colorado BLM Planning Areas.
- (T) The Cumulative Emissions scenario that includes new O&G development on Federal and non-Federal lands and mining development on Federal lands within the 13 Colorado BLM Planning areas plus new O&G development for the Mancos Shale area in northern New Mexico.
- (U) Emissions from all O&G development throughout the 4 km CARMMS domain (new Federal and non-Federal O&G through the domain plus Federal mining in Colorado).
- (V) Natural emissions (biogenic, fires, lightning, WBD and sea salt).
- (W) All emissions from the 2021 CAMx simulation (total concentrations).
- (X) All emissions from the 2008 CAMx base case simulation (total concentrations).

⁶⁸ $C [\text{ppm}] = C [\mu\text{g}/\text{m}^3] / (40.9 \times \text{MW})$, where MW = molecular weight in g/mole. This formula assumes 1 atmosphere pressure and 298 K temperature. <http://www.colorado.gov/airquality/permits/guide.pdf>

Table 4-2. 24 Source apportionment post-processing Source Groups that separate AQ/AQRV impacts at Class I and sensitive Class II areas will be disclosed for the 2021 emission scenarios and 2008 base case.

Processing Source Group	Source Group Name	Source Category No. (See Table 4-1)
A through N	See Table 4-1 for names of the new Federal O&G from the 14 BLM Planning Areas Source Categories #2 through #15	Separately #2 - #15
O	Total Colorado River Field Office	#4 and #5
P	Total Royal Gorge Field Office	#10, #11, #12 #13 and #14
Q	Mining from 13 Colorado BLM Planning Areas	#18
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	#2 - #14 and #18
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	#2 - #14 plus #16 and #18
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	#2 - #16 and #18
U	Combined O&G and Mining in 4 km domain	#2 - #19
V	Natural Emissions	#1
W	2021 All Emissions	#1 - #20
X	2008 Base Case All Emissions	--

Table 4-3. Applicable National and State Ambient Air Quality Standards and PSD concentration increments (bold indicates units in which standard was defined, conversion to ppm/ppb following CDPHE modeling guidance and with the exception of ozone that will be reported in ppb, all modeled concentrations will be reported in $\mu\text{g}/\text{m}^3$).

Pollutant/Averaging Time	NAAQS	CAAQS ¹³	NMAAQs ¹⁴	PSD Class I Increment ¹	PSD Class II Increment ¹
CO					
1-hour ²	35 ppm 40,000 $\mu\text{g}/\text{m}^3$	--	13.1 ppm 1,100 $\mu\text{g}/\text{m}^3$	--	--
8-hour ²	9 ppm 10,000 $\mu\text{g}/\text{m}^3$	--	8.7 ppm 10,000 $\mu\text{g}/\text{m}^3$	--	--
NO₂					
1-hour ³	100 ppb 188 $\mu\text{g}/\text{m}^3$	--	--	--	--
24-hour	--	--	0.10 ppm 1,953 $\mu\text{g}/\text{m}^3$	--	--
Annual ⁴	53 ppb 100 $\mu\text{g}/\text{m}^3$	--	0.05 ppm 98 $\mu\text{g}/\text{m}^3$	2.5 $\mu\text{g}/\text{m}^3$	25 $\mu\text{g}/\text{m}^3$
O₃					
8-hour ⁵	0.075 ppm 147 $\mu\text{g}/\text{m}^3$	--	--	--	--
PM₁₀					
24-hour ⁶	150 $\mu\text{g}/\text{m}^3$	--	--	8 $\mu\text{g}/\text{m}^3$	30 $\mu\text{g}/\text{m}^3$
Annual ⁷	--	--	--	4 $\mu\text{g}/\text{m}^3$	17 $\mu\text{g}/\text{m}^3$
PM_{2.5}					
24-hour ⁸	35 $\mu\text{g}/\text{m}^3$	--	--	2 $\mu\text{g}/\text{m}^3$	9 $\mu\text{g}/\text{m}^3$
Annual ⁹	12 $\mu\text{g}/\text{m}^3$	--	--	1 $\mu\text{g}/\text{m}^3$	4 $\mu\text{g}/\text{m}^3$
SO₂					
1-hour ¹⁰	75 ppb 196 $\mu\text{g}/\text{m}^3$	--	--		
3-hour ¹¹	0.5 ppm 1,300 $\mu\text{g}/\text{m}^3$	700 $\mu\text{g}/\text{m}^3$	--	25 $\mu\text{g}/\text{m}^3$	512 $\mu\text{g}/\text{m}^3$
24-hour ¹²	--	--	0.10 ppm 262 $\mu\text{g}/\text{m}^3$	5 $\mu\text{g}/\text{m}^3$	91 $\mu\text{g}/\text{m}^3$
Annual ⁴	--	--	0.02 ppm 52 $\mu\text{g}/\text{m}^3$	2 $\mu\text{g}/\text{m}^3$	20 $\mu\text{g}/\text{m}^3$

1. The PSD demonstrations serve information purposes only and do not constitute a regulatory PSD increment consumption analysis.
2. No more than one exceedance per calendar year; for NMAAQs - No more than one exceedance per consecutive 12 months
3. 98th percentile, averaged over 3 year; for NMAAQs - not to be exceeded more than once over any 12 consecutive months
4. Annual mean not to be exceeded; for NMAAQs - arithmetic average over any four consecutive quarters not to be exceeded
5. Fourth-highest daily maximum 8-hour ozone concentrations in a year, averaged over 3 years
6. Not to be exceeded more than once per calendar year on average over 3 years.
7. 3 year average of the arithmetic means over a calendar year
8. 98th percentile, averaged over 3 years
9. Annual mean, averaged over 3 years, NAAQS promulgated December 14, 2012
10. 99th percentile of daily maximum 1-hour concentrations in a year, averaged over 3 years
11. No more than one exceedance per calendar year (secondary NAAQS) and no more than one exceedance in 12 consecutive months (CAAQS)
12. For areas in New Mexico not within 3.5 miles of the Chino Mines Company
13. <http://www.colorado.gov/cs/Satellite/CDPHE-Main/CBON/1251601911433>
14. <http://www.nmcpr.state.nm.us/nmac/parts/title20/20.002.0003.htm>

4.3 Class I and Sensitive Class II Areas for Analysis

The BLM COSO and NMSO and their contractors worked with the IAQRT to identify the Class I and sensitive Class II areas where the AQ/AQRV impacts due to O&G development on Federal lands within the Colorado BLM Planning Areas would be assessed. With the addition of the Mancos Shale development area in northwest New Mexico in the CARMMS analysis, the BLM NMSO reached out to the IAQRT to assist in identifying additional Class I and sensitive Class II areas to analyze in the analysis. Responses were received from NPS, USFS and FWS and a Technical Memorandum was prepared dated September 2, 2014 (Parker and Morris, 2014) for the NMSO that identified the Class I and sensitive Class II areas for the CARMMS analysis. Although the Class I area list did not change, several additional sensitive Class II areas were added to the CARMMS post-processing list that were within 300 km of the Mancos Shale development area.

The Class I and sensitive Class II areas were also analyzed and a few areas that overlapped or were adjacent were consolidated. In addition, new shapefiles of the Class I/II areas were acquired and GIS analysis was performed to define the grid cell definition of the Class I/II areas. This resulted in changes to the grid cell definitions of the Class I/II areas (i.e., receptors) from what was used in the CARMMS May 2014 preliminary draft report. Section 4.3.1 describes the procedures used and examples on how the grid cell definitions of the Class II/II areas were performed.

4.3.1 Final Class I and Sensitive Class II Areas

The Class I areas where air quality and AQRV impacts were calculated within the 4 km CARMMS modeling domain are displayed in Figure 4-2 and listed in Table 4-4. The sensitive Class II areas used in the CARMMS post-processing are displayed in Figure 4-3 by FLM ownership and listed in Table 4-5. Note that several of the Class I areas are portions of a sensitive Class II area. In total, the CARMMS modeling results were post-processed using 26-27 and 58 Class I and sensitive Class II areas, respectively. Details on how the sensitive Class II areas were defined are provided in Parker and Morris (2014). Note that the Colorado side of Dinosaur National Monument is considered PSD Class I for just SO₂. Sensitive lakes in the region where acid neutralizing capacity (ANC) calculations will be made are listed in Table 4-6.

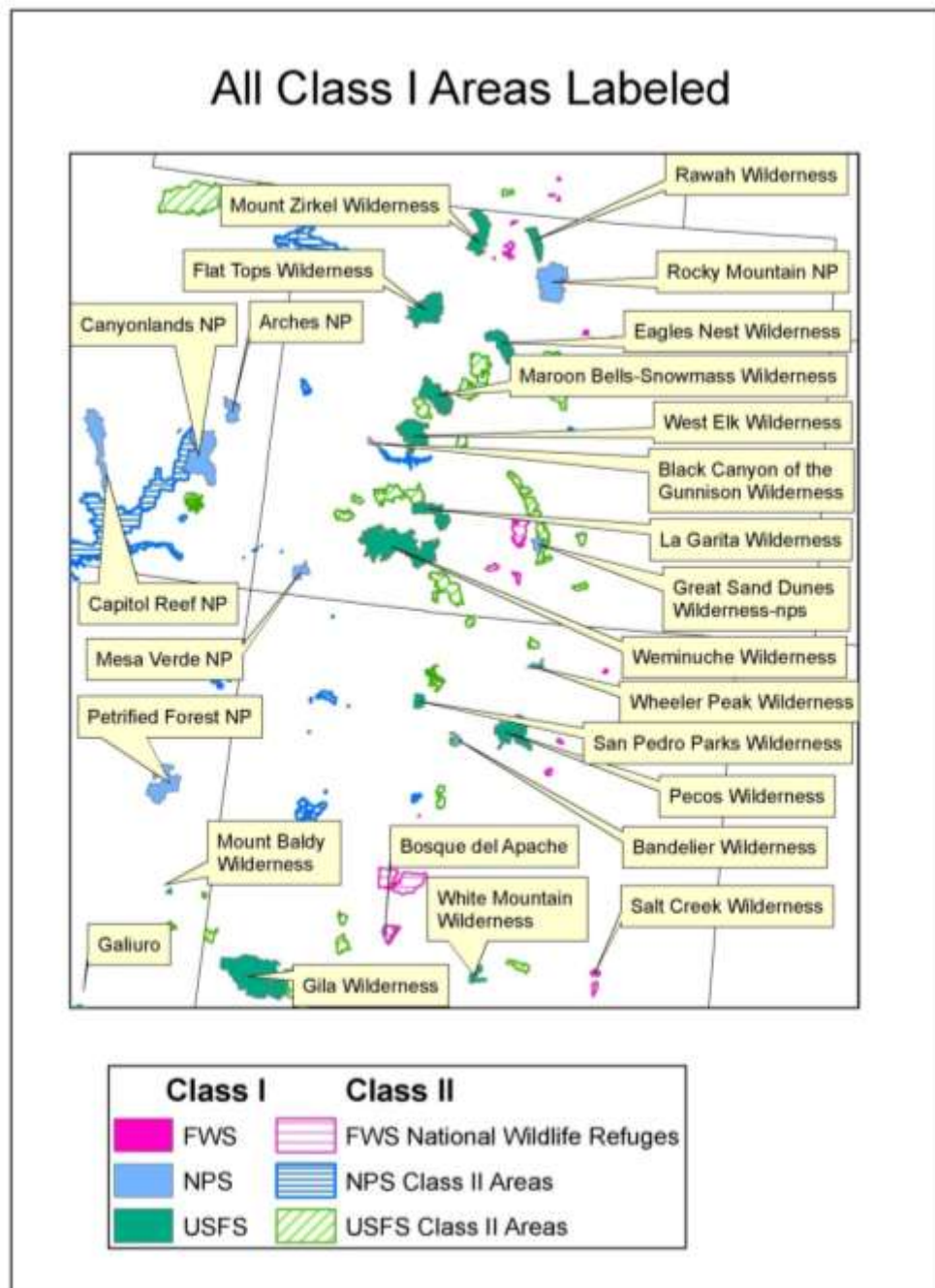


Figure 4-2. Locations of Class I (dark green) and sensitive Class II (light green) areas where air quality and AQRV impacts were assessed as well as sensitive lakes (blue dots) where ANC calculations will be made (Class I areas are labeled).

Table 4-4. List of Class I Areas for Impact Analysis

Class I Area	State	FLM
Arches NP	UT	NPS
Bandelier Wilderness	NM	NPS
Black Canyon of the Gunnison National Park	CO	NPS
Bosque del Apache Wilderness	NM	FWS
Canyonlands NP	UT	NPS
Capitol Reef NP	UT	NPS
Eagles Nest Wilderness	CO	USFS
Flat Tops Wilderness	CO	USFS
Galiuro Wilderness	AZ	USFS
Gila Wilderness	NM	USFS
Great Sand Dunes Wilderness-NPS	CO	NPS
La Garita Wilderness	CO	USFS
Maroon Bells-Snowmass Wilderness	CO	USFS
Mesa Verde NP	CO	NPS
Mount Baldy Wilderness	AZ	USFS
Mount Zirkel Wilderness	CO	USFS
Pecos Wilderness	NM	USFS
Petrified Forest NP	AZ	NPS
Rawah Wilderness	CO	USFS
Rocky Mountain NP	CO	NPS
Salt Creek Wilderness	NM	FWS
San Pedro Parks Wilderness	NM	USFS
Weminuche Wilderness	CO	USFS
West Elk Wilderness	CO	USFS
Wheeler Peak Wilderness	NM	USFS
White Mountain Wilderness	NM	USFS
Dinosaur NM ¹	UT & CO	NPS
1. The Colorado side of Dinosaur NM is PSD Class I for SO ₂		

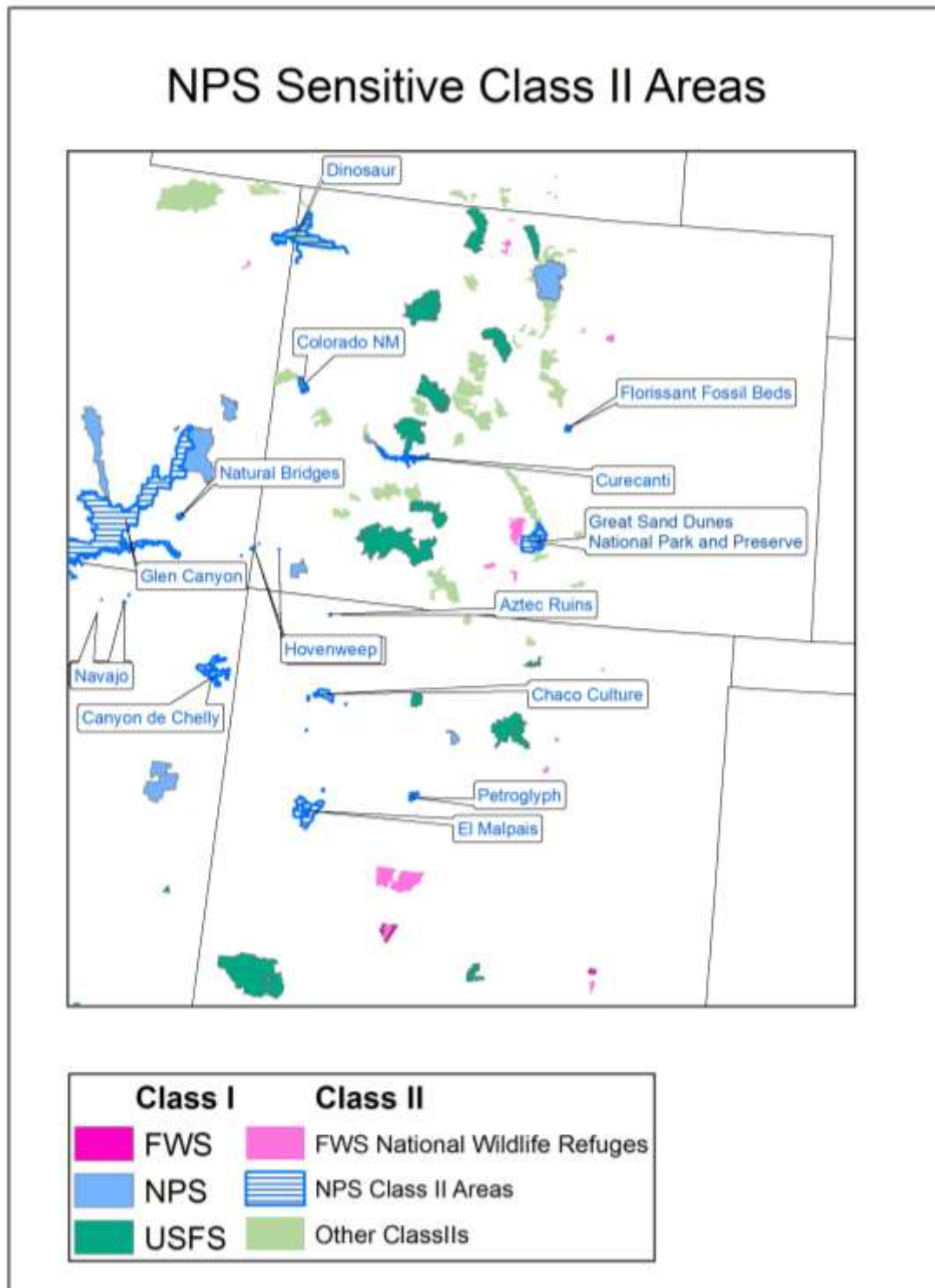


Figure 4-3a. NPS sensitive Class II areas for the CARMMS analysis labeled. Class I areas and non-NPS sensitive Class II areas unlabeled.

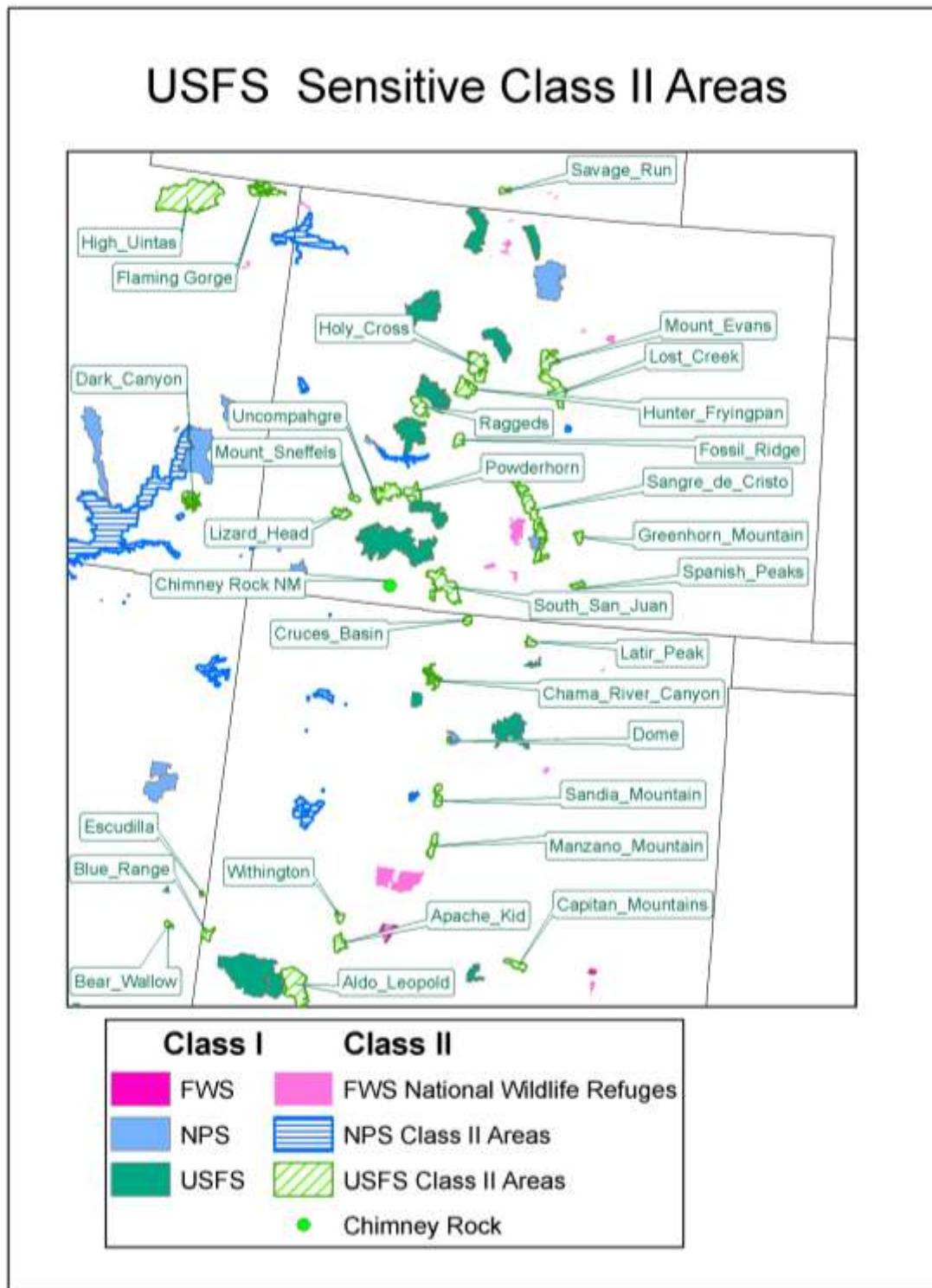


Figure 4-3b. USFS sensitive Class II areas for the CARMMS analysis labeled. Class I area and non-USFS Class II areas displayed but not labeled.

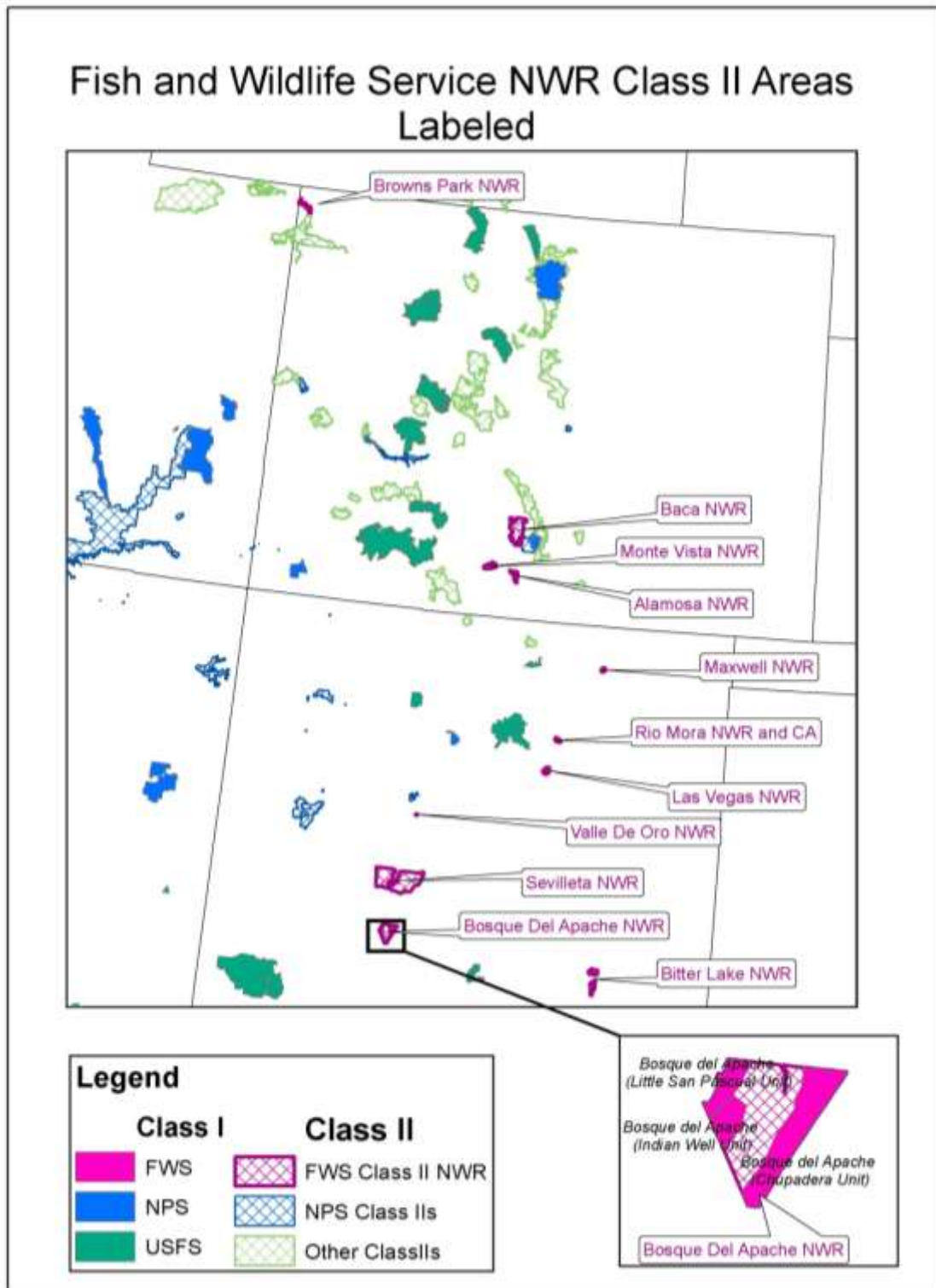


Figure 4-3c. FWS sensitive Class II areas for the CARMMS analysis labeled. Class I areas and non-FWS areas shown but not labeled.

Table 4-5. Sensitive Class II areas where air quality and AQRV impacts were assessed.

Sensitive Class II Area	State	FLM
Alamosa NWR	CO	FWS
Aldo Leopold Wilderness	NM	USFS
Apache Kid Wilderness	NM	USFS
Aztec Ruins NM	NM	NPS
Baca NWR	CO	FWS
Bear Wallow Wilderness	AZ	USFS
Bitter Lake NWR	NM	FWS
Blue Range Wilderness	NM	USFS
Bosque Del Apache NWR	NM	FWS
Browns Park NWR	CO	FWS
Canyon de Chelly NM	AZ	NPS
Capitan Mountains Wilderness	NM	USFS
Chaco Culture NHP	NM	NPS
Chama River Canyon Wilderness	NM	USFS
Chimney Rock NM	CO	USFS
Colorado NM	CO	NPS
Cruces Basin Wilderness	NM	USFS
Curecanti NRA	CO	NPS
Dark Canyon Wilderness	UT	USFS
Dinosaur NM	CO	NPS
Dome Wilderness	NM	USFS
El Malpais NM	NM	NPS
Escudilla Wilderness	AZ	USFS
Flaming Gorge	UT	USFS
Florissant Fossil Beds NM	CO	NPS
Fossil Ridge Wilderness	CO	USFS
Glen Canyon NRA	UT	NPS
Great Sand Dunes National Park	CO	NPS
Great Sand Dunes National Preserve	CO	NPS
Greenhorn Mountain Wilderness	CO	USFS
High Uintas Wilderness	UT	USFS
Holy Cross Wilderness	CO	USFS
Hovenweep NM	CO	NPS
Hunter-Fryingpan Wilderness	CO	USFS
Las Vegas NWR	NM	FWS
Latir Peak Wilderness	NM	USFS
Lizard Head Wilderness	CO	USFS
Lost Creek Wilderness	CO	USFS
Manzano Mountain Wilderness	NM	USFS
Maxwell NWR	NM	FWS
Monte Vista NWR	CO	FWS
Mount Evans Wilderness	CO	USFS
Mount Sneffels Wilderness	CO	USFS
Natural Bridges NM	UT	NPS
Navajo NM	AZ	NPS

Table 4-6. Sensitive lakes where ANC calculations were made.

Lake	National Forest Name	Wilderness Name
Walk Up Lake	Ashley National Forest	
Tabor Lake	White River National Forest	Collegiate Peaks Wilderness
Brooklyn Lake	White River National Forest	Collegiate Peaks Wilderness
Booth Lake	White River National Forest	Eagles Nest Wilderness
Upper Willow Lake	White River National Forest	Eagles Nest Wilderness
Upper Ned Wilson Lake	White River National Forest	Flat Tops Wilderness
Lower Nwl Packtrail Pothole	White River National Forest	Flat Tops Wilderness
Ned Wilson Lake	White River National Forest	Flat Tops Wilderness
Upper Nwl Packtrail Pothole	White River National Forest	Flat Tops Wilderness
Dean Lake	Ashley National Forest	High Uintas Wilderness
No Name (Utah; Duchesne - 4d2-039)	Ashley National Forest	High Uintas Wilderness
Fish Lake	Wasatch-Cache National Forest	High Uintas Wilderness
Bluebell	ASHLEY NATIONAL FOREST	HIGH UINTAS WILDERNESS
Upper Coffin	Ashley National Forest	High Uintas Wilderness
Blodgett Lake, Colorado	White River National Forest	Holy Cross Wilderness
Upper Turquoise Lake	White River National Forest	Holy Cross Wilderness
Upper West Tennessee Lake	San Isabel National Forest	Holy Cross Wilderness
Blue Lake (Colorado; Boulder - 4e1-040)	Arapaho And Roosevelt National Forests	Indian Peaks Wilderness
No Name (Colorado; Boulder - 4e1-055)	Arapaho And Roosevelt National Forests	Indian Peaks Wilderness
King Lake (Colorado; Grand - 4e1-049)	Arapaho And Roosevelt National Forests	Indian Peaks Wilderness
Crater Lake (Colorado; Grand - 4e1-041)	Arapaho And Roosevelt National Forests	Indian Peaks Wilderness
Upper Lake	Arapaho And Roosevelt National Forests	Indian Peaks Wilderness
Small Lake Above U-Shaped Lake	Rio Grande National Forest	La Garita Wilderness
U-Shaped Lake	Rio Grande National Forest	La Garita Wilderness
Moon Lake (Upper)	White River National Forest	Maroon Bells-Snowmass Wilderness
Avalanche Lake	White River National Forest	Maroon Bells-Snowmass Wilderness
Capitol Lake	White River National Forest	Maroon Bells-Snowmass Wilderness
Upper Middle Beartrack Lake	Arapaho And Roosevelt National Forests	Mount Evans Wilderness
South Lake (Colorado)	Pike And San Isabel National Forests	Mount Evans Wilderness
Abyss Lake	Pike And San Isabel National Forests	Mount Evans Wilderness
North Lake (Colorado)	Pike And San Isabel National Forests	Mount Evans Wilderness
Frozen Lake	Pike And San Isabel National Forests	Mount Evans Wilderness
Seven Lakes (Lg.East)	Medicine Bow-Routt National Forest	Mount Zirkel Wilderness
Summit Lake (Colorado;	Medicine Bow-Routt National Forest	Mount Zirkel Wilderness

Lake	National Forest Name	Wilderness Name
Jackson - 4e2-060)		
Lake Elbert	Medicine Bow-Routt National Forest	Mount Zirkel Wilderness
Deep Creek Lake, Colorado	Gunnison National Forest	Raggeds Wilderness
Rawah Lake #4	Arapaho And Roosevelt National Forests	Rawah Wilderness
Island Lake	Arapaho And Roosevelt National Forests	Rawah Wilderness
Kelly Lake (Colorado)	Arapaho And Roosevelt National Forests	Rawah Wilderness
Upper Stout Lake	San Isabel National Forest	Sangre De Cristo Wilderness
Upper Little Sand Creek Lake	San Isabel National Forest	Sangre De Cristo Wilderness
Lower Stout Lake	San Isabel National Forest	Sangre De Cristo Wilderness
Crater Lake (Sangre De Cristo)	Rio Grande National Forest	Sangre De Cristo Wilderness
Lake South Of Blue Lakes	San Juan-Rio Grande National Forest	South San Juan Wilderness
Glacier Lake (Colorado)	San Juan-Rio Grande National Forest	South San Juan Wilderness
Little Eldorado Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
White Dome Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Lake Due South Of Ute Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Big Eldorado Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Small Pond Above Trout Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Upper Sunlight Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Upper Grizzly Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
West Snowdon Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Middle Ute Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Little Granite Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Lower Sunlight Lake	San Juan-Rio Grande National Forest	Weminuche Wilderness
Four Mile Pothole	San Juan-Rio Grande National Forest	Weminuche Wilderness
South Golden Lake	Grand Mesa, Uncompahgre And Gunnison National Forests	West Elk Wilderness

4.3.2 Class I and Sensitive Class II Area Grid Cell Assignments

The list of CAMx grid cells that represent each Class I/II area changed slightly between the preliminary analysis as documented in the May 2014 report and the final analysis reported here. For some of the Class I/II areas, the CAMx grid cells used to represent the areas are identical in the preliminary and final analyses, these areas include Galiuro Wilderness, Mt Baldy Wilderness and Colorado NM. For some other Class I/II areas, the CAMx grid cells used to represent the areas differ by a single grid cell (of about 100 total grid cells). The final results for these areas are usually expected to be very close to the preliminary results, those areas include Canyonlands National Park and Rocky Mountain National Park. Some of the other Class I/II areas have more grid cell differences between the preliminary and final analysis.

Determining the grid cells that represent the Class I/II areas is achieved with Graphical Information System (GIS) software, and is performed by intersecting the CAMx model grid cells

with GIS shapefiles that define the Class I/II boundaries. Different GIS tools are available to perform the intersection that assigns a Class I/II designation to each grid cell, and different input shapefiles defining the boundaries are also available.

To generate the grid cells for the final analysis, we used official Class I boundary shapefiles that are available for download from the NPS website⁶⁹. The GIS tool “spatial join” was used to assign a Class I/II area to each CAMx grid cell if any part of the Class I/II area intersects the grid cell, even if the Class I/II area only covers a small fraction of the grid cell. For example, Figure 4-4 displays the La Garita Wilderness Class I area boundary and grid cells (receptors) representing that area, the numbers displayed in the grid cells are the i and j coordinates of the CARMMS 4 km domain modeling grid. In Figure 4-4 it can be seen that many of the grid cells covering the boundary of La Garita have more than 50% of the grid cell area outside of the La Garita boundary, these grid cells may not have been used in the preliminary analysis. In fact there are numerous grid cells assigned to the La Garita Wilderness where the Class I area covers less than 10 percent of the grid cell. The inclusion of any grid cell that intersects any part of the Class I area no matter how small introduces conservatism in the analysis. In addition, for the final processing, attention was paid to grid cells that cover more than one Class I/II area, in those cases, a particular grid cell was used twice to represent 2 different neighboring Class I/II areas. Figure 4-5 provides an example of a grid cell (56_153) that is used to represent both Black Canyon of the Gunnison Class I area and Curecanti NPS Class II area. Figure 4-6 displays a quality assurance (QA) plot showing all the Class I areas (including the Colorado side of Dinosaur NM, since it is considered a Class I area for SO₂), overlaid with the grid cells used to represent the Class I/II areas in the final analysis.

⁶⁹ <http://www.nature.nps.gov/air/maps/classiloc.cfm>

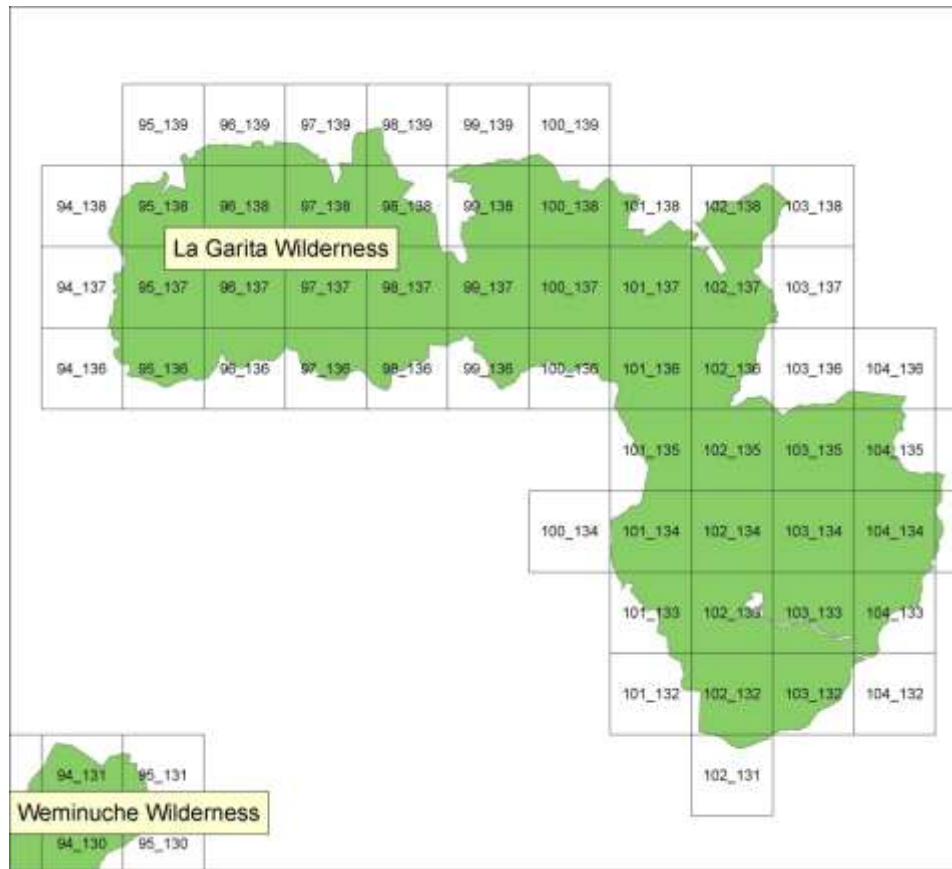


Figure 4-4. La Garita Wilderness Area represented by 4 km grid cells.

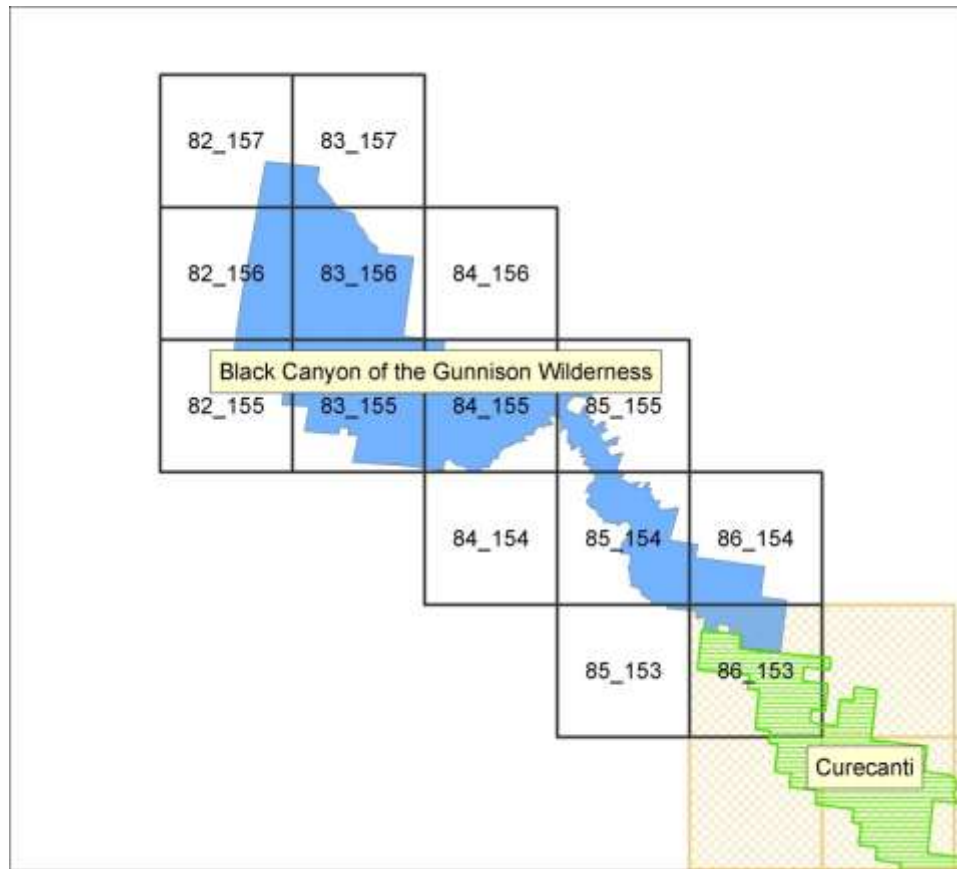


Figure4-5. Example of Black Canyon of the Gunnison Class I area grid cell overlap with Curecanti Class II area.

Class I Areas with Grid Cells

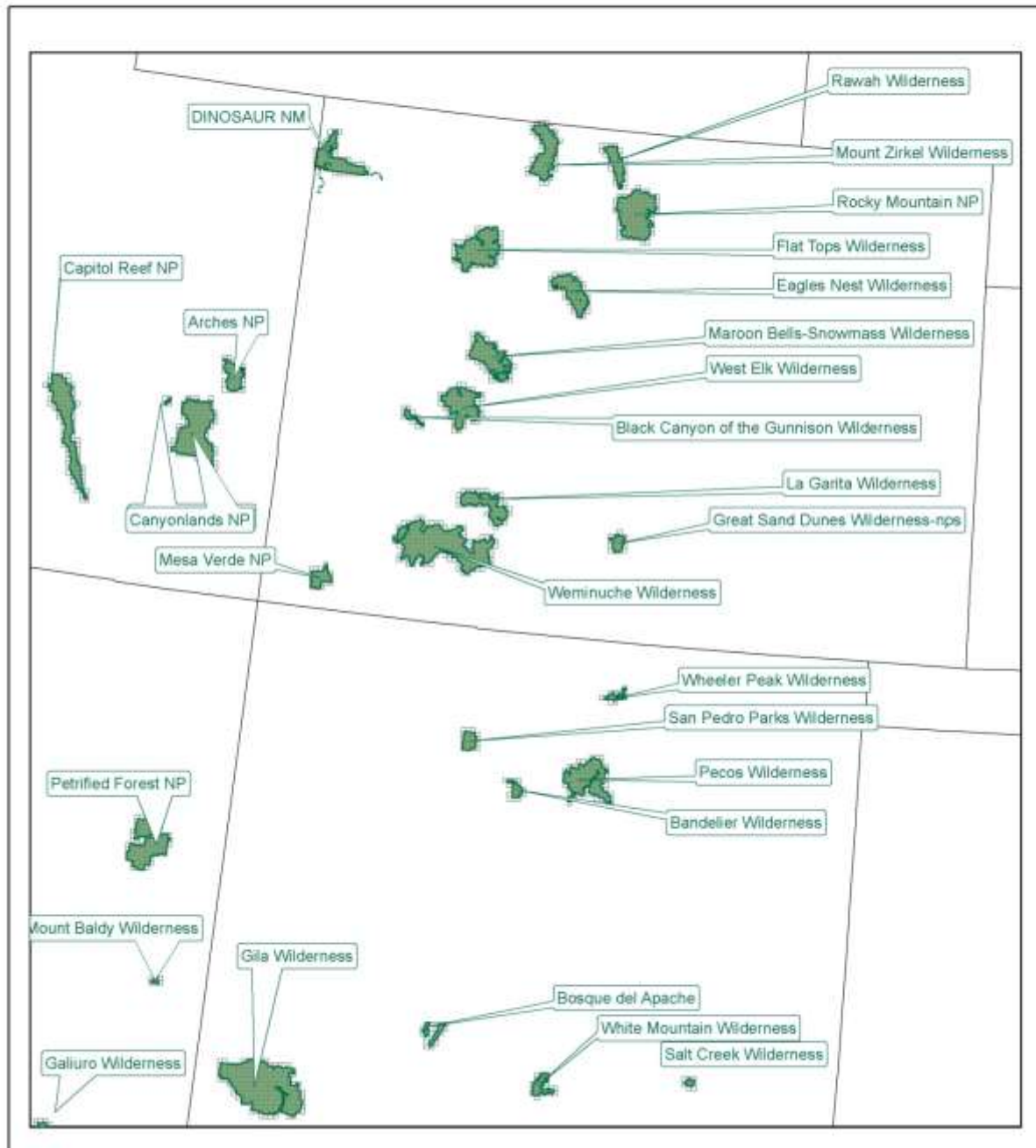


Figure 4-6. QA Plot showing all Class I Areas and CARMMS 4 km grid cell receptors that represent the areas.

4.4 Ambient Concentration Analysis using Absolute Modeling Results

Modeled concentrations predicted by the CAMx due to all sources were compared against national and state standards (NAAQS, CAAQS and NMAAQs, see Table 4-3) throughout the 4 km modeling domain. When exceedances of the ozone or PM_{2.5} NAAQS are estimated, the APCA and PSAT source apportionment results were used to determine the contribution of emissions from each of the Source Groups to determine the major cause of the modeled exceedance. The incremental air quality concentration contribution due to emissions from oil and gas on Federal lands at Class I and sensitive Class II areas for each BLM planning area were compared to applicable PSD increments (see Table 4-3). The PSD demonstrations are for information only and are not regulatory PSD Increment consumption analyses, which would be completed as necessary by the relevant state or other agency.

4.5 Ambient Concentration Analysis using Relative Modeling Results

EPA's modeling guidance recommends using the PGM modeling results in a relative fashion when comparing future year modeling results to the ozone and PM_{2.5} NAAQS (EPA, 2007). The relative change in the PGM concentrations between the current and future year simulations are used to scale the observed current year ozone or PM_{2.5} Design Value (DVC) to obtain a projected future year Design Value (DVF). The model derived scaling factors are called Relative Response Factors (RRFs) and are based on the ratio of future year to current year modeling results:

$$DVF = DVC \times RRF$$

EPA's PGM modeling guidance provides recommended procedures for calculating DVCs and RRFs (EPA, 2007) that have been implemented in EPA's Modeled Attainment Test Software (MATS⁷⁰; Abt, 2012). The MATS projection tool was used with the CAMx 2008 Base Case and 2021 High, Low and Medium Development Scenarios modeling results to project future year ozone DVFs that were compared to the NAAQS. MATS also has a capability of projecting PM_{2.5} DVFs but there is much less observed PM_{2.5} data in the region so such projections would be extremely limited, so MATS was not used for PM_{2.5}. The MATS default settings for making future year ozone projections were used that includes using a current year Design Value (DVC) based on an average of three-years of Design Values (DVs) centered on the Base Case modeling year (2008) and constructing RRFs using at least 10 days of modeling results. As the Base Case year is 2008, then this means using a DVC based on DVs from the following 3-year periods, 2006-2008, 2007-2009 and 2008-2010.

4.6 Visibility Analysis

Visibility impacts were calculated for new oil and gas emissions on Federal lands within each BLM Planning Areas as well as for cumulative emissions sources. The approach used the incremental concentrations as quantified by the CAMx PSAT tool simulation of oil and gas and mining activities within each BLM planning area. Changes in light extinction from CAMx model

⁷⁰ http://www.epa.gov/ttn/scram/modelingapps_mats.htm

concentration increments due to emissions from oil and gas and other activity emissions were calculated for each day at grid cells that intersect Class I and sensitive Class II areas within the 4 km modeling domain (see Section 4.3.2). The FLAG (2010) procedures were used in the incremental BLM planning area-specific visibility assessment analysis.

The visibility evaluation metric used in this analysis is based on the Haze Index which is measured in deciview (dv) units and is defined as follows:

$$HI = 10 \times \ln[b_{\text{ext}}/10] .$$

b_{ext} is the atmospheric light extinction measured in inverse megameters (Mm^{-1}) and is calculated primarily from atmospheric concentrations of particulates. A more intuitive measure of haze is visual range (VR), which is defined as the distance at which a large black object just disappears from view, and is measured in km. Visual range is related to b_{ext} by the formula $VR = 3912 / b_{\text{ext}}$. Visual range will not be used as a threshold in the analysis, but could be back-calculated from extinction to give a more easily understood visibility metric.

The incremental concentrations due to BLM planning area emissions were added to background concentrations in the extinction equation (b_{ext}) and the difference between the Haze Index with added BLM planning area concentrations to the Haze Index based solely on background concentrations is calculated. This quantity is the change in Haze Index, which is referred to as “delta deciview” (Δdv) :

$$\Delta dv = 10 \times \ln[b_{\text{ext(BLM+background)}}/10] - 10 \times \ln[b_{\text{ext(background)}}/10]$$

$$\Delta dv = 10 \times \ln[b_{\text{ext(BLM+background)}}/b_{\text{ext(background)}}]$$

Here $b_{\text{ext(BLM+background)}}$ refers to atmospheric light extinction due to oil and gas and other activities in each BLM planning area plus background concentrations, and $b_{\text{ext(background)}}$ refers to atmospheric light extinction due to background concentrations only.

For each individual BLM Planning Areas, the estimated visibility degradation at the Class I areas and sensitive Class II areas due to new O&G emissions on Federal lands are presented in terms of the number of days that exceed a threshold change in deciview (Δdv) relative to background conditions. In the next section we describe the method for calculating the extinction, b_{ext} .

4.6.1 IMPROVE Reconstructed Mass Extinction Equations

The FLAG (2010) procedures for evaluating visibility impacts at Class I areas use the revised IMPROVE reconstructed mass extinction equation to convert PM species in μgm^{-3} to light extinction (b_{ext}) in inverse megameters (Mm^{-1}) as follows:

$$b_{\text{ext}} = b_{\text{SO}_4} + b_{\text{NO}_3} + b_{\text{EC}} + b_{\text{OCM}} + b_{\text{Soil}} + b_{\text{PMC}} + b_{\text{SeaSalt}} + b_{\text{Rayleigh}} + b_{\text{NO}_2}$$

where

$$b_{\text{SO}_4} = 2.2 \times f_s(\text{RH}) \times [\text{Small Sulfate}] + 4.8 \times f_L(\text{RH}) \times [\text{Large Sulfate}]$$

$$b_{\text{NO}_3} = 2.4 \times f_s(\text{RH}) \times [\text{Small Nitrate}] + 5.1 \times f_L(\text{RH}) \times [\text{Large Nitrate}]$$

$$b_{\text{OCM}} = 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}]$$

$$b_{\text{EC}} = 10 \times [\text{Elemental Carbon}]$$

$$b_{\text{Soil}} = 1 \times [\text{Fine Soil}]$$

$$b_{\text{CM}} = 0.6 \times [\text{Coarse Mass}]$$

$$b_{\text{SeaSalt}} = 1.7 \times f_{\text{SS}}(\text{RH}) \times [\text{Sea Salt}]$$

$$b_{\text{Rayleigh}} = \text{Rayleigh Scattering (Site-specific)}$$

$$b_{\text{NO}_2} = 0.33 \times [\text{NO}_2 \text{ (ppb)}] \text{ \{or as: } 0.1755 \times [\text{NO}_2 \text{ (}\mu\text{g/m}^3\text{)}]\text{ \}}$$

$f(\text{RH})$ are relative humidity adjustment factors that account for the fact that sulfate, nitrate and sea salt aerosols are hygroscopic and are more effective at scattering radiation at higher relative humidity. FLAG (2010) recommends using monthly average $f(\text{RH})$ values rather than the hourly averages recommended in the previous FLAG (2000) guidance document in order to moderate the effects of extreme weather events on the visibility results.

The revised IMPROVE equation treats “large sulfate” and “small sulfate” separately because large and small aerosols affect an incoming beam of light differently. However, the IMPROVE measurements do not separately measure large and small sulfate; they measure only the total $\text{PM}_{2.5}$ sulfate. Similarly, CAMx writes out a single concentration of particulate sulfate for each grid cell. Part of the definition of the new IMPROVE equation is a procedure for calculating the large and small sulfate contributions based on the magnitude of the model output sulfate concentrations; the procedure is documented in FLAG (2010). The sulfate concentration magnitude is used as a surrogate for distinguishing between large and small sulfate concentrations. For a given grid cell, the large and small sulfate contributions are calculated from the model output sulfate (which is the “Total Sulfate” referred to in the FLAG (2010) guidance) as:

For Total Sulfate < 20 $\mu\text{g/m}^3$:

$$[\text{Large Sulfate}] = ([\text{Total Sulfate}] / 20 \mu\text{g/m}^3) \times [\text{Total Sulfate}]$$

For Total Sulfate $\geq 20 \mu\text{g/m}^3$:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}]$$

For all values of Total Sulfate:

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

The procedure is identical for nitrate and organic mass. Sulfate, nitrate and organic mass concentrations for the western U.S. are expected to be mainly in the small fraction.

The PSAT source apportionment algorithm does not separately track NO₂ concentrations but instead tracks total reactive nitrogen (RGN) that consist mainly of NO plus NO₂. Thus for each hour and each grid cell representing a Class I/II area, a Source Group's incremental PSAT RGN contribution is converted to NO₂ by multiplying by the total (all emissions) CAMx model NO₂/RGN concentration ratio, which is then used in the IMPROVE visibility equation.

Although sodium and particulate chloride are treated in the CAMx core model, these species are not carried in the CAMx PSAT tool; neglecting sea salt in the visibility calculations in the 4 km CARMMS impact assessment domains does not compromise the accuracy of the analysis as IMPROVE measurements show that sea salt concentrations are negligible in this inland area and there would be no sea salt associated with any of the O&G emissions.

Predicted daily average modeled concentrations due to each BLM planning area for grid cells containing Class I and sensitive Class II area receptors were processed using the revised IMPROVE reconstructed mass extinction equation FLAG (2010) to obtain changes in b_{ext} at each sensitive receptor area that are converted to deciview and reported.

The FLAG (2010) method was used to estimate the visibility impacts from each Colorado and northern New Mexico BLM Planning Area. This method used the revised IMPROVE equation together with annual average natural conditions (see Table 6 in FLAG, 2010) and monthly relative humidity factors for each Class I area (see Tables 7-9 in FLAG, 2010). The Δdv was calculated for each grid cell that overlaps a Class I or sensitive Class II area for each day of the annual CAMx run. The highest Δdv across all grid cells overlapping a Class I or sensitive Class II area was selected to represent the daily value at that Class I/II area. Visibility impacts due to new O&G emissions on Federal lands within each BLM Planning Areas that are more than 0.5 and 1.0 dv will be reported.

4.6.2 Cumulative Visibility

The cumulative visibility impacts due to the development of oil and gas and other (e.g., mining) activities on all BLM Planning Areas were assessed following the recommendations from the FWS and NPS that was outlined in their February 10, 2012 letter to the Wyoming Department of Environmental Quality on recommended cumulative visibility method for the Continental Divide-Creston gas infill development EIS (FWS and NPS, 2012) and subsequent conversations with the FLMS. This approach is based on an abbreviated regional haze rule method that estimates the future year visibility at Class I and sensitive Class II areas for the average of the Worst 20% (W20%) and Best 20% (B20%) visibility days with and without the effects of the cumulative emissions on visibility impairment. The cumulative visibility impacts used CAMx model output from the 2008 Base Case and 2021 emissions scenarios in conjunction with monitoring data to produce cumulative visibility impacts at each Class I area in the CARMMS domain. EPA's Modeled Attainment Test Software (MATS⁷¹) was used to make the 2021 visibility projections for the W20% and B20% days. The basic steps in the recommended cumulative visibility method are as follows (FWS and NPS, 2012):

⁷¹ http://www.epa.gov/ttn/scram/modelingapps_mats.htm

1. Calculate the observed average 2008 current year cumulative visibility impact using the Haze Index (HI, in deciviews) at each Class I or associated sensitive Class II area to determine the 20% of days with the worst and 20% of days with the best visibility. The intent is to incorporate 5 years of monitoring data surrounding the 2008 Base Case year, which would include 2006-2010. MATS uses the IMPROVE data associate with each Class I area and modeling results at the location of the IMPROVE monitoring site will be used.
2. Estimate the relative response factors (RRFs) for each component of PM_{2.5} and for coarse mass (CM) corresponding to the new IMPROVE visibility algorithm using the CAMx 2008 and 2021 model output.
3. Using the RRFs and ambient data, calculate 2021 future-year daily concentration data for the B20% and W20% days using the CAMx 2008 Base Case and 2021 standard model concentration estimates and PSAT source apportionment modeling results two ways:
 - a. 2021 Total Emissions: Use total 2021 High, Low and Medium Development Scenario CAMx concentration results due to all emissions;
 - b. 2021 No Cumulative Emissions: Use PSAT source apportionment results to eliminate contributions of PM concentrations associated with combined emission scenarios corresponding to Source Groups R,S,T and U in Table 4-2.
4. Use the information in step 3 to calculate the average 2021 visibility for the 20% Best and 20% Worst visibility days and the 2021 emissions.
5. Assess the average differences in cumulative visibility impacts for the four combined scenarios and also compare with the current observed Baseline visibility conditions.

4.7 Sulfur and Nitrogen Deposition

CAMx-predicted wet and dry fluxes of sulfur- and nitrogen-containing species were processed to estimate total annual sulfur (S) and nitrogen (N) deposition values at each Class I and sensitive Class II area as well as at each acid sensitive lake. The Maximum annual S and N deposition values from any grid cell that intersects a Class I or sensitive Class II receptor area was used to represent deposition for that area, in addition to the Average annual deposition values of all grid cells that intersect a Class I or sensitive Class II receptor area. Maximum and Average predicted S and N deposition impacts were estimated separately for each BLM planning area and together across all BLM planning areas using the Source Groups in Table 4-2.

Nitrogen deposition impacts were calculated by taking the sum of the nitrogen contained in the fluxes of all nitrogen species modeled by CAMx PSAT source apportionment tool. CAMx species used in the nitrogen deposition flux calculation are: reactive gaseous nitrate species, RGN (NO, NO₂, NO₃ radical, HONO, N₂O₅), TPN (PAN, PANX, PNA), organic nitrates (NTR), particulate nitrate formed from primary emissions plus secondarily formed particulate nitrate (NO₃), gaseous nitric acid (HNO₃), gaseous ammonia (NH₃) and particulate ammonium (NH₄). CAMx species used in the sulfur deposition calculation are primarily sulfur dioxide emissions (SO₂) and particulate sulfate ion from primary emissions plus secondarily formed sulfate (SO₄).

FLAG (2010) recommends that applicable sources assess impacts of nitrogen and sulfur deposition at Class I areas. This guidance recognizes the importance of establishing critical deposition loading values ("Critical Loads") for each specific Class I area as these Critical Loads are completely dependent on local atmospheric, aquatic and terrestrial conditions and chemistry. Critical Load thresholds are essentially a level of atmospheric pollutant deposition below which negative ecosystem effects are not likely to occur. FLAG (2010) does not include any Critical Load levels for specific Class I areas and refers to site-specific critical load information on FLM websites for each area of concern. This guidance does, however recommend the use of deposition analysis thresholds (DATs⁷²) developed by the National Park Service and the Fish and Wildlife Service. The DATs represent screening level values for nitrogen and sulfur deposition for individual projects with deposition impacts below the DATS considered negligible. DAT have been established for both nitrogen and sulfur deposition and in western Class I areas they are 0.005 kilograms per hectare per year (kg/ha/yr) for both nitrogen and sulfur deposition. As a screening analysis, results for oil and gas and mining activities for each BLM planning area, which is Source Groups A through P were separately compared to the DATs. Comparison of deposition impacts from combined Source Groups to the DAT is not appropriate.

For the combined Source Groups and total 2008 and 2021 emissions Source Groups W and X, the annual nitrogen and sulfur deposition were compared against Critical Load values established for the Rocky Mountain region to assess total deposition impacts. The NPS has provided recent information on nitrogen critical load values applicable for Wyoming and Colorado Class I and sensitive Class II areas (NPS, 2014). For Class I and sensitive Class II areas in Wyoming a critical load value of 2.2 kg/ha/yr for nitrogen deposition (estimated from a wet deposition critical load value of 1.4 kg N/ha/yr) is applicable, based on research conducted by Saros et. al.(2010) in the eastern Sierra Nevada and Greater Yellowstone ecosystems. This is a critical load value that is protective of high elevation surface waters. For Colorado Class I and sensitive Class II areas (with the exception of Dinosaur National Monument) a critical load value 2.3 kg N/ha/yr is applicable for total nitrogen deposition, based on research conducted by Jill Baron (Baron 2006) that estimated 1.5 kg/ha/yr as a critical loading value for wet nitrogen deposition for high-elevation lakes in Rocky Mountain National Park, Colorado. For Dinosaur National Monument, which is an arid region, a nitrogen deposition critical load value is based on research conducted by Pardo et al. (2011) which concluded that the cumulative critical load necessary to protect shrublands and lichen communities in Dinosaur NM is 3 kg N/ha/year.

For sulfur deposition, the critical load threshold published by Fox et al. (Fox 1989) for total sulfur deposition of 5 kg/ha/yr, for the Bob Marshall Wilderness Area in Montana and Bridger Wilderness Area in Wyoming, was used as critical load threshold for each of the Class I and sensitive Class II areas.

In summary, we will compare the total annual sulfur and nitrogen deposition amounts for the cumulative Source Groups Q through X to the following Critical Load values:

⁷² <http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf>

Nitrogen

- Wyoming – 2.2 kg/ha/yr
- Colorado – 2.3 kg/ha/yr, except for Dinosaur Monument that will use 3.0 kg/ha/yr

Sulfur

- 5.0 kg/ha/yr – all areas

4.8 Acid Neutralizing Capacity

In addition to calculation of total deposition fluxes, an additional analysis was performed to assess the change in water chemistry associated with atmospheric deposition from BLM oil and gas and mining activities and cumulative sources for each of the sensitive lakes listed in Table 4-5. This analysis assesses the change in the acid neutralizing capacity (ANC) of sensitive lakes. An estimate of potential changes in ANC was made by following the procedure developed by the USFS Rocky Mountain Region (USFS, 2000). Predicted changes in ANC are compared with the threshold (10 percent change in ANC for lakes with background ANC values greater than 25 micro equivalents per liter [$\mu\text{eq/L}$], and no more than a 1 $\mu\text{eq/L}$ change in ANC for lakes with background ANC values equal to or less than 25 $\mu\text{eq/L}$). A list of sensitive lakes was obtained from the USFS (Table 4-5). The most recent lake chemistry background ANC data was obtained from the VIEWS website for each of the sensitive lakes in the 4 km CARMMS modeling domain.

5.0 2021 MODELING RESULTS

In this Chapter we present the CARMMS modeling results for the 2021 High, Low and Medium Development Scenarios following the procedures given in Chapter 4 using examples from the 24 Source Group contributions given in Table 4-2. Electronic attachments are provided that contain modeling results for all of the Source Groups with summaries provided in this Chapter. In this Chapter we present results for several Source Groups as examples given below, results for the rest of the Source Groups are provided in the interactive electronic attachments:

- (E) New O&G on Federal lands within the BLM Grand Junction Field Office (GJFO) Planning Area;
- (F) New O&G on Federal lands in the BLM Uncompahgre Field Office (UFO) Planning Area;
- (J) New O&G on Federal lands within the U.S. Forest Service Pawnee Grasslands Planning Area(USFS-PG);
- (R) New O&G and mining on Federal lands within the 13 Colorado Planning Areas;
- (T) New O&G on Federal and non-Federal lands and mining on Federal lands within the 14 BLM Planning Areas (Colorado and northern New Mexico BLM Planning Areas0; and
- (U) All O&G (new Federal and non-Federal as well as existing) and Federal mining in Colorado within the 4 km CARMMS domain.

5.1 PSD Pollutant Concentration Impacts at Class I and Sensitive Class II Areas

Attachment A-1, A-2 and A-3 are three Excel spreadsheets that contain the contributions of emissions from each Source Group listed in Table 4-2 to pollutant concentrations at the 27 Class I (Table 4-4) and 58 sensitive Class II (Table 4-5) areas for the, respectively, 2021 High, Low and Medium Development Scenarios. Results are presented for each PSD pollutant and averaging time given in Table 4-3. Attachment A contains two pivot table sheets:

The first pivot table sheet is “Summary” that lists the impacts of a user selected Source Group to all PSD pollutants across all Class I/II areas. It is controlled by selecting the Source Group in cell B1 and whether contributions of the maximum receptor or average across all receptors in a Class I/II area is desired in cell B2; we always select the “Maximum” option. If a concentration at a Class I or sensitive Class II area is above the, respectively, PSD Class I or II Increments, the cell is shaded yellow.

The second pivot table sheet is “MaxImpact” and for a user-selected PSD pollutant it lists the maximum concentration impact at any Class I and sensitive Class II area due to emissions from each Source Group along with the percentage the concentration is of the PSD Increment and the Class I and II area where the maximum occurs. The pivot table is

controlled by selecting the pollutant and averaging time in cell B1 and whether maximum or average concentrations across the Class I/II area is desired in cell B2.

The sheet “Readme” has a brief explanation of the sheets in the spreadsheet and maps for the locations of the Class I and sensitive Class II areas.

The PSD incremental concentrations are reported for informational purposes only and the analyses presented in this section are not a comprehensive PSD increment consumption assessment, which must be performed by the appropriate state or federal agency.

5.1.1 Maximum PSD Concentration Impacts at any Class I or II Area

EPA has defined PSD Concentrations Increments for Class I and II areas for 8 different pollutant concentration/averaging time combinations (see Table 4-3). In this section we present the “Maximum” PSD concentration impacts at Class I and sensitive Class II areas due to each of the relevant 24 Source Groups from Table 4-2 (i.e., from the MaxImpact sheet in Attachments A-1 and A-2). The modeled impacts are based on the CAMx PSAT source apportionment contributions. For short-term averaging times (i.e., not annual), the highest second high concentration at each Class I/II area is selected for comparison with the PSD increment.

5.1.1.1 Annual NO₂ PSD Concentrations

The maximum (highest 2nd high) contribution to annual NO₂ concentrations at any Class I or sensitive Class II area due to emissions from the 24 Source Groups for the 2021 High, Low and Medium Development Scenarios are shown in Table 5-1, which was obtained from the MaxImpact sheet in Attachments A-1, A-2 and A-3. The Class I and II PSD Increments for annual NO₂ are 2.5 and 25 µg/m³, respectively. The annual NO₂ contributions from each of the individual BLM Planning Areas in Colorado and northern New Mexico (i.e., Source Groups A through P) are all below the annual NO₂ PSD Increment in all Class I and sensitive Class II areas for all three 2021 emission scenarios. The BLM Planning Area with the highest annual NO₂ concentration contribution to any Class I area is the BLM Colorado Tres Rios Field Office (TRFO) Planning Area whose annual NO₂ concentration contribution at Mesa Verde National Park for the 2021 High Development Scenarios is 1.97 µg/m³, which represents 79% of the Class I area Increment. The mitigation in the 2021 Medium Development Scenario reduces this impact by -16% to 1.66 µg/m³, which represents 66% of the PSD Class I area annual NO₂ increment. The corresponding TRFO annual NO₂ impact for the Low Development Scenario is 0.24 µg/m³, which represents 9% of the Class I increment. The maximum annual NO₂ contribution at any Class I area from any other of the 14 BLM Planning Areas are less than 5% of the Class I area NO₂ PSD Increment. The highest annual NO₂ concentration at any sensitive Class II area due to new O&G emissions on Federal lands in any of the 14 BLM Planning Areas is the New Mexico Farmington Field Office (NMFFO) with a 2.0 µg/m³ annual NO₂ at the Aztec Ruins Class II area that represents 8% of the PSD Class II area Increment; recall that the same high emissions scenario was used for the BLM NMFFO Planning Area for both the CARMMS 2021 High and Low Development Scenarios. The NMFFO Planning Area new Federal O&G annual NO₂ impacts at Mesa Verde for the 2021 Medium Development Scenario is 1.6 µg/m³ that is -23% lower than seen for the 2021 High Development Scenario.

The maximum annual NO₂ contribution due to all new O&G and mining on Federal lands within the 13 Colorado BLM Planning Areas combined (i.e., Source Group R) for the High, Low and Medium Development Scenarios are, respectively, 1.98, 0.24 and 1.67 µg/m³ at Mesa Verde National Park, which represents 79%, 10% and 67% of the NO₂ PSD Class I increment and is primarily due to Federal O&G emissions from the TRFO Planning Area as discussed above. For the Cumulative Emissions Scenario that represents all new O&G on both Federal and non-Federal lands and mining within the 14 CO/NM BLM Planning Areas (Source Group T) the maximum NO₂ contribution are 4.5, 2.9 and 4.1 µg/m³ for the High, Low and Medium Development Scenarios, respectively, that are above the annual NO₂ PSD Class I Increment (2.5 µg/m³). The maximum contribution of the Cumulative Emissions Scenario (T) to annual NO₂ at any sensitive Class II area is 4.1 µg/m³ for the High Scenario at the South San Juan Class II area, 3.0 µg/m³ at the Aztec Ruins Class II area for the Low Scenario and 3.7 µg/m³ for the Medium Development Scenario all of which are below the Class II area annual NO₂ PSD Increment. Finally, the maximum annual NO₂ contribution at any Class I area due to the combined effects of all O&G development in the 4 km CARMS domain plus Federal mining in Colorado (Source Group U) is 4.8 µg/m³ for the High, 3.1 µg/m³ for the Low and 4.4 µg/m³ for the Medium Development Scenarios both occurring at Mesa Verde.

Table 5-1a. Maximum annual NO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	NO ₂ , Annual	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2.5	0.019	0.8%	Mount_Zirkel	25	0.031	0.1%	Dinosaur_all
B	White River FO	2.5	0.117	4.7%	Flat_Tops	25	0.451	1.8%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2.5	0.025	1.0%	Flat_Tops	25	0.010	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	2.5	0.025	1.0%	Flat_Tops	25	0.009	0.0%	Holy_Cross
E	Grand Junction FO	2.5	0.079	3.2%	Arches	25	0.149	0.6%	Colorado
F	Uncompahgre FO	2.5	0.105	4.2%	Maroon_Bells	25	0.164	0.7%	Raggeds
G	Tres Rios FO	2.5	1.968	78.7%	Mesa_Verde	25	1.921	7.7%	South_San_Juan
H	Kremmling FO	2.5	0.036	1.4%	Rawah	25	0.011	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2.5	0.000	0.0%	Rocky_Mountain	25	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2.5	0.001	0.0%	Rocky_Mountain	25	0.001	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2.5	0.000	0.0%	Salt_Creek	25	0.001	0.0%	Maxwell_NWR
L	RGFO#3 -- South	2.5	0.003	0.1%	Great_Sand_Dunes	25	0.190	0.8%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2.5	0.000	0.0%	Eagles_Nest	25	0.015	0.1%	Lost_Creek
N	New Mexico Farmington District	2.5	0.042	1.7%	Mesa_Verde	25	2.041	8.2%	Aztec_Ruins
O	Total Colorado River Field Office	2.5	0.050	2.0%	Flat_Tops	25	0.020	0.1%	Holy_Cross
P	Total Royal Gorge Field Office	2.5	0.003	0.1%	Great_Sand_Dunes	25	0.191	0.8%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2.5	0.011	0.4%	West_Elk	25	0.017	0.1%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2.5	1.979	79.1%	Mesa_Verde	25	1.927	7.7%	South_San_Juan
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2.5	4.477	179.1%	Mesa_Verde	25	4.033	16.1%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2.5	4.498	179.9%	Mesa_Verde	25	4.086	16.3%	South_San_Juan
U	Combined O&G and Mining in 4 km domain	2.5	4.779	191.2%	Mesa_Verde	25	20.535	82.1%	Aztec_Ruins
V	Natural Emissions	2.5	2.698	107.9%	Bandelier	25	1.226	4.9%	Dome
W	2021 All Emissions	2.5	6.100	244.0%	Mesa_Verde	25	26.453	105.8%	Aztec_Ruins
X	2008 All Emissions	2.5	15.638	625.5%	Eagles_Nest	25	23.759	95.0%	Aztec_Ruins

Table 5-1b. Maximum annual NO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	NO ₂ , Annual	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2.5	0.003	0.1%	Mount_Zirkel	25	0.004	0.0%	Dinosaur_all
B	White River FO	2.5	0.019	0.8%	Flat_Tops	25	0.071	0.3%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2.5	0.016	0.6%	Flat_Tops	25	0.006	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	2.5	0.013	0.5%	Flat_Tops	25	0.005	0.0%	Holy_Cross
E	Grand Junction FO	2.5	0.004	0.2%	Maroon_Bells	25	0.008	0.0%	Colorado
F	Uncompahgre FO	2.5	0.031	1.2%	Maroon_Bells	25	0.050	0.2%	Raggeds
G	Tres Rios FO	2.5	0.236	9.4%	Mesa_Verde	25	0.236	0.9%	South_San_Juan
H	Kremmling FO	2.5	0.004	0.2%	Rawah	25	0.001	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2.5	0.000	0.0%	Rocky_Mountain	25	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2.5	0.000	0.0%	Rocky_Mountain	25	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2.5	0.000	0.0%	Salt_Creek	25	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	2.5	0.002	0.1%	Great_Sand_Dunes	25	0.118	0.5%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2.5	0.000	0.0%	Eagles_Nest	25	0.002	0.0%	Lost_Creek
N	New Mexico Farmington District	2.5	0.042	1.7%	Mesa_Verde	25	2.040	8.2%	Aztec_Ruins
O	Total Colorado River Field Office	2.5	0.029	1.2%	Flat_Tops	25	0.011	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	2.5	0.002	0.1%	Great_Sand_Dunes	25	0.118	0.5%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2.5	0.011	0.4%	West_Elk	25	0.017	0.1%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2.5	0.239	9.6%	Mesa_Verde	25	0.238	1.0%	South_San_Juan
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2.5	2.850	114.0%	Mesa_Verde	25	2.500	10.0%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2.5	2.870	114.8%	Mesa_Verde	25	2.971	11.9%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	2.5	3.146	125.8%	Mesa_Verde	25	20.491	82.0%	Aztec_Ruins
V	Natural Emissions	2.5	2.698	107.9%	Bandelier	25	1.226	4.9%	Dome
W	2021 All Emissions	2.5	5.620	224.8%	Petrified_Forest	25	26.407	105.6%	Aztec_Ruins
X	2008 All Emissions	2.5	15.638	625.5%	Eagles_Nest	25	23.759	95.0%	Aztec_Ruins

Table 5-1c. Maximum annual NO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	NO ₂ , Annual	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2.5	0.016	0.6%	Mount_Zirkel	25	0.027	0.1%	Dinosaur_all
B	White River FO	2.5	0.089	3.6%	Flat_Tops	25	0.424	1.7%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2.5	0.019	0.8%	Flat_Tops	25	0.008	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	2.5	0.020	0.8%	Flat_Tops	25	0.008	0.0%	Holy_Cross
E	Grand Junction FO	2.5	0.075	3.0%	Arches	25	0.137	0.5%	Colorado
F	Uncompahgre FO	2.5	0.071	2.9%	Maroon_Bells	25	0.111	0.4%	Raggeds
G	Tres Rios FO	2.5	1.660	66.4%	Mesa_Verde	25	1.627	6.5%	South_San_Juan
H	Kremmling FO	2.5	0.031	1.2%	Eagles_Nest	25	0.007	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2.5	0.000	0.0%	Rocky_Mountain	25	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2.5	0.001	0.0%	Rocky_Mountain	25	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2.5	0.000	0.0%	Salt_Creek	25	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	2.5	0.002	0.1%	Great_Sand_Dunes	25	0.132	0.5%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2.5	0.000	0.0%	Eagles_Nest	25	0.008	0.0%	Lost_Creek
N	New Mexico Farmington District	2.5	0.033	1.3%	Mesa_Verde	25	1.573	6.3%	Aztec_Ruins
O	Total Colorado River Field Office	2.5	0.040	1.6%	Flat_Tops	25	0.016	0.1%	Holy_Cross
P	Total Royal Gorge Field Office	2.5	0.002	0.1%	Great_Sand_Dunes	25	0.132	0.5%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2.5	0.011	0.4%	West_Elk	25	0.017	0.1%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2.5	1.669	66.8%	Mesa_Verde	25	1.631	6.5%	South_San_Juan
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2.5	4.087	163.5%	Mesa_Verde	25	3.679	14.7%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2.5	4.103	164.1%	Mesa_Verde	25	3.720	14.9%	South_San_Juan
U	Combined O&G and Mining in 4 km domain	2.5	4.383	175.3%	Mesa_Verde	25	20.080	80.3%	Aztec_Ruins
V	Natural Emissions	2.5	2.698	107.9%	Bandelier	25	1.226	4.9%	Dome
W	2021 All Emissions	2.5	5.703	228.1%	Mesa_Verde	25	26.011	104.0%	Aztec_Ruins
X	2008 All Emissions	2.5	15.638	625.5%	Eagles_Nest	25	23.759	95.0%	Aztec_Ruins

5.1.1.2 SO₂ PSD Concentrations

Tables 5-2 through 5-4 presents the comparison of the, respectively, maximum annual, 24-hour and 3-hour SO₂ concentrations at Class I/II areas with the PSD SO₂ increments for the 24 Source Groups. Note that the Colorado portion of the Dinosaur National Monument is Class I for SO₂ only, so it is included in the Class I area grouping in these Tables. None of the Source Groups exceed the annual PSD Class I Increment at any Class I/II area (Table 5-2). For 24-hour and 3-hour SO₂ contributions, there are wildfires that cause exceedances of the PSD Class I increment at the Bandelier Class I area for the Natural, total 2021 and total 2008 (Source Groups V, X and W) emission groups, but none of the other Source Groups exhibit any exceedances of the 24-hour and 3-hour SO₂ PSD Increments at any Class I or sensitive Class II area. Note that PSD Increments are not applicable for Natural or Total emissions. The contributions of the 14 BLM Planning Areas to SO₂ concentrations at Class I/II areas are extremely small, mostly much less than 1% of the PSD Increments. Of the 14 BLM Planning Areas, Federal O&G from the White River Field Office (WRFO) Planning Area has by far the largest contribution to annual, 24-hour and 3-hour SO₂ concentrations at any Class I area with maximum contributions of 5, 8 and 5 percent of the PSD Increment for the High and Medium Development Scenarios (the mitigation in the Medium Development Scenario did not address SO₂ emissions) and approximately 1 percent of the PSD Increment for the Low Development Scenarios that occurs at the Colorado portion of Dinosaur National Monument.

Table 5-2a. Maximum annual SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	SO ₂ Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2	0.000	0.0%	Mount_Zirkel	20	0.000	0.0%	Dinosaur_all
B	White River FO	2	0.089	4.5%	Dinosaur_CO	20	0.089	0.4%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
E	Grand Junction FO	2	0.000	0.0%	Arches	20	0.001	0.0%	Colorado
F	Uncompahgre FO	2	0.000	0.0%	Maroon_Bells	20	0.000	0.0%	Raggeds
G	Tres Rios FO	2	0.001	0.1%	Mesa_Verde	20	0.001	0.0%	South_San_Juan
H	Kremmling FO	2	0.000	0.0%	Rawah	20	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2	0.000	0.0%	Salt_Creek	20	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	2	0.000	0.0%	Great_Sand_Dunes	20	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2	0.000	0.0%	Eagles_Nest	20	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	2	0.000	0.0%	Mesa_Verde	20	0.003	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2	0.000	0.0%	West_Elk	20	0.000	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2	0.090	4.5%	Dinosaur_CO	20	0.090	0.4%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2	0.102	5.1%	Dinosaur_CO	20	0.102	0.5%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2	0.102	5.1%	Dinosaur_CO	20	0.102	0.5%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	2	0.108	5.4%	Dinosaur_CO	20	0.108	0.5%	Dinosaur_all
V	Natural Emissions	2	0.410	20.5%	Bandelier	20	0.171	0.9%	Dome
W	2021 All Emissions	2	1.857	92.8%	Galiuro	20	0.968	4.8%	Bitter_Lake_NWR
X	2008 All Emissions	2	1.240	62.0%	Petrified_Forest	20	1.143	5.7%	Aztec_Ruins

Table 5-2b. Maximum annual SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	SO ₂ , Annual	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2	0.000	0.0%	Mount_Zirkel	20	0.000	0.0%	Dinosaur_all
B	White River FO	2	0.014	0.7%	Dinosaur_CO	20	0.014	0.1%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
E	Grand Junction FO	2	0.000	0.0%	Arches	20	0.000	0.0%	Colorado
F	Uncompahgre FO	2	0.000	0.0%	Maroon_Bells	20	0.000	0.0%	Raggeds
G	Tres Rios FO	2	0.000	0.0%	Mesa_Verde	20	0.000	0.0%	South_San_Juan
H	Kremmling FO	2	0.000	0.0%	Rawah	20	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2	0.000	0.0%	Pecos	20	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	2	0.000	0.0%	Great_Sand_Dunes	20	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2	0.000	0.0%	Eagles_Nest	20	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	2	0.000	0.0%	Mesa_Verde	20	0.003	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2	0.000	0.0%	West_Elk	20	0.000	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2	0.014	0.7%	Dinosaur_CO	20	0.014	0.1%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2	0.018	0.9%	Dinosaur_CO	20	0.018	0.1%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2	0.018	0.9%	Dinosaur_CO	20	0.018	0.1%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	2	0.024	1.2%	Dinosaur_CO	20	0.083	0.4%	Aztec_Ruins
V	Natural Emissions	2	0.410	20.5%	Bandelier	20	0.171	0.9%	Dome
W	2021 All Emissions	2	1.857	92.8%	Galiuro	20	0.968	4.8%	Bitter_Lake_NWR
X	2008 All Emissions	2	1.240	62.0%	Petrified_Forest	20	1.143	5.7%	Aztec_Ruins

Table 5-2c. Maximum annual SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	SO ₂ , Annual	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2	0.000	0.0%	Mount_Zirkel	20	0.000	0.0%	Dinosaur_all
B	White River FO	2	0.089	4.5%	Dinosaur_CO	20	0.089	0.4%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
E	Grand Junction FO	2	0.000	0.0%	Arches	20	0.001	0.0%	Colorado
F	Uncompahgre FO	2	0.000	0.0%	Maroon_Bells	20	0.000	0.0%	Raggeds
G	Tres Rios FO	2	0.001	0.1%	Mesa_Verde	20	0.001	0.0%	South_San_Juan
H	Kremmling FO	2	0.000	0.0%	Rawah	20	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2	0.000	0.0%	Salt_Creek	20	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	2	0.000	0.0%	Great_Sand_Dunes	20	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2	0.000	0.0%	Eagles_Nest	20	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	2	0.000	0.0%	Mesa_Verde	20	0.003	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	2	0.000	0.0%	Flat_Tops	20	0.000	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	2	0.000	0.0%	Rocky_Mountain	20	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2	0.000	0.0%	West_Elk	20	0.000	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2	0.090	4.5%	Dinosaur_CO	20	0.090	0.4%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2	0.102	5.1%	Dinosaur_CO	20	0.102	0.5%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2	0.102	5.1%	Dinosaur_CO	20	0.102	0.5%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	2	0.108	5.4%	Dinosaur_CO	20	0.108	0.5%	Dinosaur_all
V	Natural Emissions	2	0.410	20.5%	Bandelier	20	0.171	0.9%	Dome
W	2021 All Emissions	2	1.857	92.8%	Galiuro	20	0.968	4.8%	Bitter_Lake_NWR
X	2008 All Emissions	2	1.240	62.0%	Petrified_Forest	20	1.143	5.7%	Aztec_Ruins

Table 5-3a. Maximum 24-hour SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	SO ₂ , 24-hour	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	5	0.002	0.0%	Dinosaur_CO	91	0.002	0.0%	Dinosaur_all
B	White River FO	5	0.412	8.2%	Dinosaur_CO	91	0.412	0.5%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
D	Roan Plateau Planning area portion of CRVFO	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
E	Grand Junction FO	5	0.002	0.0%	Arches	91	0.003	0.0%	Colorado
F	Uncompahgre FO	5	0.001	0.0%	Maroon_Bells	91	0.001	0.0%	Raggeds
G	Tres Rios FO	5	0.003	0.1%	Mesa_Verde	91	0.003	0.0%	South_San_Juan
H	Kremmling FO	5	0.000	0.0%	Rawah	91	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	5	0.000	0.0%	Pecos	91	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	5	0.000	0.0%	Great_Sand_Dunes	91	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	5	0.000	0.0%	Eagles_Nest	91	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	5	0.001	0.0%	Mesa_Verde	91	0.009	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
P	Total Royal Gorge Field Office	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	5	0.001	0.0%	West_Elk	91	0.002	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	5	0.412	8.2%	Dinosaur_CO	91	0.412	0.5%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	5	0.469	9.4%	Dinosaur_CO	91	0.469	0.5%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	5	0.469	9.4%	Dinosaur_CO	91	0.469	0.5%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	5	0.487	9.7%	Dinosaur_CO	91	0.565	0.6%	Aztec_Ruins
V	Natural Emissions	5	50.751	1015.0%	Bandelier	91	20.045	22.0%	Dome
W	2021 All Emissions	5	51.160	1023.2%	Bandelier	91	20.791	22.8%	Dome
X	2008 All Emissions	5	50.921	1018.4%	Bandelier	91	20.894	23.0%	Dome

Table 5-3b. Maximum 24-hour SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	SO ₂ , 24-hour	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	5	0.000	0.0%	Dinosaur_CO	91	0.000	0.0%	Dinosaur_all
B	White River FO	5	0.067	1.3%	Dinosaur_CO	91	0.067	0.1%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
D	Roan Plateau Planning area portion of CRVFO	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
E	Grand Junction FO	5	0.000	0.0%	Arches	91	0.000	0.0%	Colorado
F	Uncompahgre FO	5	0.000	0.0%	Maroon_Bells	91	0.000	0.0%	Raggeds
G	Tres Rios FO	5	0.001	0.0%	Mesa_Verde	91	0.001	0.0%	South_San_Juan
H	Kremmling FO	5	0.000	0.0%	Rawah	91	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	5	0.000	0.0%	Pecos	91	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	5	0.000	0.0%	Great_Sand_Dunes	91	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	5	0.000	0.0%	Eagles_Nest	91	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	5	0.001	0.0%	Mesa_Verde	91	0.009	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
P	Total Royal Gorge Field Office	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	5	0.001	0.0%	West_Elk	91	0.002	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	5	0.067	1.3%	Dinosaur_CO	91	0.067	0.1%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	5	0.085	1.7%	Dinosaur_CO	91	0.085	0.1%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	5	0.085	1.7%	Dinosaur_CO	91	0.085	0.1%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	5	0.125	2.5%	Mesa_Verde	91	0.561	0.6%	Aztec_Ruins
V	Natural Emissions	5	50.751	1015.0%	Bandelier	91	20.045	22.0%	Dome
W	2021 All Emissions	5	51.158	1023.2%	Bandelier	91	20.790	22.8%	Dome
X	2008 All Emissions	5	50.921	1018.4%	Bandelier	91	20.894	23.0%	Dome

Table 5-3c. Maximum 24-hour SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	SO ₂ , 24-hour	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	5	0.002	0.0%	Dinosaur_CO	91	0.002	0.0%	Dinosaur_all
B	White River FO	5	0.412	8.2%	Dinosaur_CO	91	0.412	0.5%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
D	Roan Plateau Planning area portion of CRVFO	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
E	Grand Junction FO	5	0.002	0.0%	Arches	91	0.003	0.0%	Colorado
F	Uncompahgre FO	5	0.001	0.0%	Maroon_Bells	91	0.001	0.0%	Raggeds
G	Tres Rios FO	5	0.003	0.1%	Mesa_Verde	91	0.003	0.0%	South_San_Juan
H	Kremmling FO	5	0.000	0.0%	Rawah	91	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	5	0.000	0.0%	Pecos	91	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	5	0.000	0.0%	Great_Sand_Dunes	91	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	5	0.000	0.0%	Eagles_Nest	91	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	5	0.001	0.0%	Mesa_Verde	91	0.007	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	5	0.000	0.0%	Flat_Tops	91	0.000	0.0%	Colorado
P	Total Royal Gorge Field Office	5	0.000	0.0%	Rocky_Mountain	91	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	5	0.001	0.0%	West_Elk	91	0.002	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	5	0.412	8.2%	Dinosaur_CO	91	0.412	0.5%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	5	0.468	9.4%	Dinosaur_CO	91	0.468	0.5%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	5	0.468	9.4%	Dinosaur_CO	91	0.468	0.5%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	5	0.487	9.7%	Dinosaur_CO	91	0.563	0.6%	Aztec_Ruins
V	Natural Emissions	5	50.751	1015.0%	Bandelier	91	20.045	22.0%	Dome
W	2021 All Emissions	5	51.160	1023.2%	Bandelier	91	20.791	22.8%	Dome
X	2008 All Emissions	5	50.921	1018.4%	Bandelier	91	20.894	23.0%	Dome

Table 5-4a. Maximum 3-hour SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	SO ₂ , 3-hour	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	25	0.005	0.0%	Dinosaur_CO	512	0.005	0.0%	Dinosaur_all
B	White River FO	25	1.262	5.0%	Dinosaur_CO	512	1.262	0.2%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	25	0.001	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
D	Roan Plateau Planning area portion of CRVFO	25	0.001	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
E	Grand Junction FO	25	0.003	0.0%	Arches	512	0.006	0.0%	Colorado
F	Uncompahgre FO	25	0.002	0.0%	Maroon_Bells	512	0.002	0.0%	Raggeds
G	Tres Rios FO	25	0.006	0.0%	Mesa_Verde	512	0.005	0.0%	South_San_Juan
H	Kremmling FO	25	0.000	0.0%	Rawah	512	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	25	0.001	0.0%	Rocky_Mountain	512	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	25	0.000	0.0%	Pecos	512	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	25	0.000	0.0%	Great_Sand_Dunes	512	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	25	0.000	0.0%	Eagles_Nest	512	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	25	0.002	0.0%	Mesa_Verde	512	0.015	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	25	0.001	0.0%	Flat_Tops	512	0.001	0.0%	Colorado
P	Total Royal Gorge Field Office	25	0.001	0.0%	Rocky_Mountain	512	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	25	0.004	0.0%	West_Elk	512	0.008	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	25	1.262	5.0%	Dinosaur_CO	512	1.262	0.2%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	25	1.435	5.7%	Dinosaur_CO	512	1.435	0.3%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	25	1.435	5.7%	Dinosaur_CO	512	1.435	0.3%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	25	1.495	6.0%	Dinosaur_CO	512	1.495	0.3%	Dinosaur_all
V	Natural Emissions	25	95.970	383.9%	Bandelier	512	64.686	12.6%	Dome
W	2021 All Emissions	25	96.160	384.6%	Bandelier	512	65.144	12.7%	Dome
X	2008 All Emissions	25	96.190	384.8%	Bandelier	512	65.161	12.7%	Dome

Table 5-4b. Maximum 3-hour SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	SO ₂ , 3-hour	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	25	0.001	0.0%	Dinosaur_CO	512	0.001	0.0%	Dinosaur_all
B	White River FO	25	0.189	0.8%	Dinosaur_CO	512	0.189	0.0%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	25	0.000	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
D	Roan Plateau Planning area portion of CRVFO	25	0.000	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
E	Grand Junction FO	25	0.000	0.0%	Arches	512	0.000	0.0%	Colorado
F	Uncompahgre FO	25	0.001	0.0%	Maroon_Bells	512	0.001	0.0%	Raggeds
G	Tres Rios FO	25	0.001	0.0%	Mesa_Verde	512	0.001	0.0%	South_San_Juan
H	Kremmling FO	25	0.000	0.0%	Rawah	512	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	25	0.000	0.0%	Pecos	512	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	25	0.000	0.0%	Great_Sand_Dunes	512	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	25	0.000	0.0%	Eagles_Nest	512	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	25	0.002	0.0%	Mesa_Verde	512	0.015	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	25	0.001	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
P	Total Royal Gorge Field Office	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	25	0.004	0.0%	West_Elk	512	0.008	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	25	0.189	0.8%	Dinosaur_CO	512	0.189	0.0%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	25	0.240	1.0%	Dinosaur_CO	512	0.240	0.0%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	25	0.240	1.0%	Dinosaur_CO	512	0.240	0.0%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	25	0.497	2.0%	Mesa_Verde	512	1.328	0.3%	Aztec_Ruins
V	Natural Emissions	25	95.970	383.9%	Bandelier	512	64.688	12.6%	Dome
W	2021 All Emissions	25	96.160	384.6%	Bandelier	512	65.140	12.7%	Dome
X	2008 All Emissions	25	96.190	384.8%	Bandelier	512	65.161	12.7%	Dome

Table 5-4c. Maximum 3-hour SO₂ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	SO ₂ , 3-hour	µg/m ³							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	25	0.005	0.0%	Dinosaur_CO	512	0.005	0.0%	Dinosaur_all
B	White River FO	25	1.262	5.0%	Dinosaur_CO	512	1.262	0.2%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	25	0.001	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
D	Roan Plateau Planning area portion of CRVFO	25	0.001	0.0%	Flat_Tops	512	0.000	0.0%	Colorado
E	Grand Junction FO	25	0.003	0.0%	Arches	512	0.006	0.0%	Colorado
F	Uncompahgre FO	25	0.002	0.0%	Maroon_Bells	512	0.002	0.0%	Raggeds
G	Tres Rios FO	25	0.006	0.0%	Mesa_Verde	512	0.005	0.0%	South_San_Juan
H	Kremmling FO	25	0.000	0.0%	Rawah	512	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	25	0.000	0.0%	Pecos	512	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	25	0.000	0.0%	Great_Sand_Dunes	512	0.000	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	25	0.000	0.0%	Eagles_Nest	512	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	25	0.001	0.0%	Mesa_Verde	512	0.012	0.0%	Aztec_Ruins
O	Total Colorado River Field Office	25	0.001	0.0%	Flat_Tops	512	0.001	0.0%	Colorado
P	Total Royal Gorge Field Office	25	0.000	0.0%	Rocky_Mountain	512	0.000	0.0%	Lost_Creek
Q	Mining from 13 Colorado BLM Planning Areas	25	0.004	0.0%	West_Elk	512	0.008	0.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	25	1.262	5.0%	Dinosaur_CO	512	1.262	0.2%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	25	1.435	5.7%	Dinosaur_CO	512	1.435	0.3%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	25	1.435	5.7%	Dinosaur_CO	512	1.435	0.3%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	25	1.495	6.0%	Dinosaur_CO	512	1.495	0.3%	Dinosaur_all
V	Natural Emissions	25	95.970	383.9%	Bandelier	512	64.686	12.6%	Dome
W	2021 All Emissions	25	96.160	384.6%	Bandelier	512	65.144	12.7%	Dome
X	2008 All Emissions	25	96.190	384.8%	Bandelier	512	65.161	12.7%	Dome

5.1.1.3 PM_{2.5} PSD Concentrations

Tables 5-5 and 5-6 displays the, respectively, maximum annual and 24-hour PM_{2.5} concentrations due the Source Groups at any Class I and II area and compares them with the PSD PM_{2.5} Increments for the 2021 High, Low and Medium Development Scenarios. PM_{2.5} concentrations due to emissions from Federal O&G within any of the 14 BLM Planning Areas do not come close to exceeding any of the PSD PM_{2.5} Increments. The BLM Planning Area with the largest Federal O&G PM_{2.5} contribution at any Class I area is the TRFO Planning Area that contributes PM_{2.5} concentrations of 9 and 15 percent for the High, 5 and 9 percent for the Medium and 1 and 2 percent for the Low Development Scenarios to the, respectively, annual and 24-hour PM_{2.5} Class I PSD Increments at the Mesa Verde Class I area. Mining on Federal land within all of the 13 Colorado BLM Planning Areas (Source Group Q) contributes a maximum of 0.16 µg/m³ for annual PM_{2.5} at Mount Zirkel and 0.79 µg/m³ for 24-hour PM_{2.5} at Flat Tops that represents 16% and 39% of the PSD Class I Increments, respectively, for all three of the 2021 Scenarios (BLM mining emissions were not altered in the three 2021 scenarios).

The maximum contribution at any Class I area to annual PM_{2.5} due to all Federal O&G and mining in the 13 Colorado BLM Planning Areas (Source Group R), the Cumulative Emissions scenario of all Federal O&G and mining and non-Federal O&G in the 14 CO/NM Planning Areas (Source Group T) and all O&G emissions throughout the 4 km CARMMS domain are, respectively, 0.18 to 0.22 µg/m³ that represents 18 to 22 percent of the Class I area increment for the High Development Scenario with similar results seen for the Medium and slightly lower values seen for the Low Development Scenarios. Similar results are seen for 24-hour PM_{2.5} with the Source Groups R, S, T and U contributing 42 to 58 percent of the 24-hour PM_{2.5} Class I Increment for the High and Medium and 40 to 43 percent of the Increment for the Low Development Scenario at Rocky Mountain National Park.

Extremely high maximum annual and 24-hour PM_{2.5} contributions are seen due to natural emissions (Source Group V) that are also reflected in the total 2021 (W) and 2008 (X) Source Groups that are due to wildfires that occurred in 2008 for which the PSD Increments are not applicable.

Note that PSD increments are not applicable to natural emissions or existing sources, thus results from Source Groups U, V, W and X are not appropriate for comparison with PSD increments.

Table 5-5a. Maximum Annual PM_{2.5} concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	PM2.5, Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	1	0.003	0.3%	Mount_Zirkel	4	0.003	0.1%	Dinosaur_all
B	White River FO	1	0.021	2.1%	Flat_Tops	4	0.046	1.2%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	1	0.003	0.3%	Flat_Tops	4	0.002	0.1%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	1	0.003	0.3%	Flat_Tops	4	0.002	0.0%	Holy_Cross
E	Grand Junction FO	1	0.011	1.1%	Maroon_Bells	4	0.023	0.6%	Colorado
F	Uncompahgre FO	1	0.012	1.2%	Maroon_Bells	4	0.017	0.4%	Raggeds
G	Tres Rios FO	1	0.087	8.7%	Mesa_Verde	4	0.084	2.1%	South_San_Juan
H	Kremmling FO	1	0.004	0.4%	Rawah	4	0.002	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	1	0.000	0.0%	Rocky_Mountain	4	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	1	0.001	0.1%	Rocky_Mountain	4	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	1	0.000	0.0%	Pecos	4	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	1	0.000	0.0%	Great_Sand_Dunes	4	0.003	0.1%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	1	0.000	0.0%	Eagles_Nest	4	0.003	0.1%	Lost_Creek
N	New Mexico Farmington District	1	0.007	0.7%	Weminuche	4	0.205	5.1%	Aztec_Ruins
O	Total Colorado River Field Office	1	0.006	0.6%	Flat_Tops	4	0.004	0.1%	Holy_Cross
P	Total Royal Gorge Field Office	1	0.001	0.1%	Rocky_Mountain	4	0.003	0.1%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	1	0.164	16.4%	Mount_Zirkel	4	0.168	4.2%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	1	0.182	18.2%	Mount_Zirkel	4	0.195	4.9%	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	1	0.216	21.6%	Mesa_Verde	4	0.224	5.6%	Raggeds
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	1	0.220	22.0%	Mesa_Verde	4	0.319	8.0%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	1	0.252	25.2%	Mesa_Verde	4	0.699	17.5%	Aztec_Ruins
V	Natural Emissions	1	9.730	973.0%	Bandelier	4	4.249	106.2%	Dome
W	2021 All Emissions	1	14.610	1461.0%	Bandelier	4	14.412	360.3%	Valle_De_Oro_NWR
X	2008 All Emissions	1	14.217	1421.7%	Bandelier	4	12.072	301.8%	Petroglyph

Table 5-5b. Maximum Annual PM_{2.5} concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	PM2.5, Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	1	0.000	0.0%	Mount_Zirkel	4	0.000	0.0%	Dinosaur_all
B	White River FO	1	0.004	0.4%	Flat_Tops	4	0.008	0.2%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	1	0.002	0.2%	Flat_Tops	4	0.001	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	1	0.002	0.2%	Flat_Tops	4	0.001	0.0%	Holy_Cross
E	Grand Junction FO	1	0.001	0.1%	Maroon_Bells	4	0.001	0.0%	Colorado
F	Uncompahgre FO	1	0.004	0.4%	Maroon_Bells	4	0.005	0.1%	Raggeds
G	Tres Rios FO	1	0.011	1.1%	Mesa_Verde	4	0.011	0.3%	South_San_Juan
H	Kremmling FO	1	0.000	0.0%	Rawah	4	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	1	0.000	0.0%	Rocky_Mountain	4	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	1	0.000	0.0%	Rocky_Mountain	4	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	1	0.000	0.0%	Pecos	4	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	1	0.000	0.0%	Great_Sand_Dunes	4	0.002	0.1%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	1	0.000	0.0%	Eagles_Nest	4	0.000	0.0%	Lost_Creek
N	New Mexico Farmington District	1	0.007	0.7%	Weminuche	4	0.205	5.1%	Aztec_Ruins
O	Total Colorado River Field Office	1	0.004	0.4%	Flat_Tops	4	0.002	0.1%	Holy_Cross
P	Total Royal Gorge Field Office	1	0.000	0.0%	Rocky_Mountain	4	0.002	0.1%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	1	0.164	16.4%	Mount_Zirkel	4	0.168	4.2%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	1	0.167	16.7%	Mount_Zirkel	4	0.175	4.4%	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	1	0.173	17.3%	Mount_Zirkel	4	0.185	4.6%	Raggeds
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	1	0.173	17.3%	Mount_Zirkel	4	0.311	7.8%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	1	0.199	19.9%	Mount_Zirkel	4	0.692	17.3%	Aztec_Ruins
V	Natural Emissions	1	9.730	973.0%	Bandelier	4	4.249	106.2%	Dome
W	2021 All Emissions	1	14.608	1460.8%	Bandelier	4	14.409	360.2%	Valle_De_Oro_NWR
X	2008 All Emissions	1	14.217	1421.7%	Bandelier	4	12.072	301.8%	Petroglyph

Table 5-5c. Maximum Annual PM_{2.5} concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	PM2.5, Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	1	0.002	0.2%	Mount_Zirkel	4	0.002	0.1%	Dinosaur_all
B	White River FO	1	0.018	1.8%	Flat_Tops	4	0.044	1.1%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	1	0.002	0.2%	Flat_Tops	4	0.002	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	1	0.002	0.2%	Flat_Tops	4	0.001	0.0%	Holy_Cross
E	Grand Junction FO	1	0.008	0.8%	Arches	4	0.020	0.5%	Colorado
F	Uncompahgre FO	1	0.008	0.8%	Maroon_Bells	4	0.011	0.3%	Raggeds
G	Tres Rios FO	1	0.048	4.8%	Mesa_Verde	4	0.045	1.1%	South_San_Juan
H	Kremmling FO	1	0.002	0.2%	Rawah	4	0.001	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	1	0.000	0.0%	Rocky_Mountain	4	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	1	0.000	0.0%	Rocky_Mountain	4	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	1	0.000	0.0%	Pecos	4	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	1	0.000	0.0%	Great_Sand_Dunes	4	0.002	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	1	0.000	0.0%	Eagles_Nest	4	0.001	0.0%	Lost_Creek
N	New Mexico Farmington District	1	0.005	0.5%	Weminuche	4	0.122	3.1%	Aztec_Ruins
O	Total Colorado River Field Office	1	0.004	0.4%	Flat_Tops	4	0.003	0.1%	Holy_Cross
P	Total Royal Gorge Field Office	1	0.000	0.0%	Rocky_Mountain	4	0.002	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	1	0.164	16.4%	Mount_Zirkel	4	0.168	4.2%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	1	0.179	17.9%	Mount_Zirkel	4	0.188	4.7%	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	1	0.191	19.1%	Mount_Zirkel	4	0.216	5.4%	Raggeds
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	1	0.191	19.1%	Mount_Zirkel	4	0.230	5.7%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	1	0.216	21.6%	Mount_Zirkel	4	0.611	15.3%	Aztec_Ruins
V	Natural Emissions	1	9.730	973.0%	Bandelier	4	4.249	106.2%	Dome
W	2021 All Emissions	1	14.609	1460.9%	Bandelier	4	14.411	360.3%	Valle_De_Oro_NWR
X	2008 All Emissions	1	14.217	1421.7%	Bandelier	4	12.072	301.8%	Petroglyph

Table 5-6a. Maximum 24-Hour PM_{2.5} concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	PM2.5, 24-hour	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2	0.031	1.6%	Mount_Zirkel	9	0.030	0.3%	Dinosaur_all
B	White River FO	2	0.133	6.6%	Flat_Tops	9	0.293	3.3%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2	0.015	0.7%	Flat_Tops	9	0.026	0.3%	Colorado
D	Roan Plateau Planning area portion of CRVFO	2	0.012	0.6%	Flat_Tops	9	0.025	0.3%	Colorado
E	Grand Junction FO	2	0.094	4.7%	Arches	9	0.242	2.7%	Colorado
F	Uncompahgre FO	2	0.060	3.0%	Maroon_Bells	9	0.062	0.7%	Raggeds
G	Tres Rios FO	2	0.302	15.1%	Mesa_Verde	9	0.260	2.9%	Hovenweep
H	Kremmling FO	2	0.011	0.5%	Mount_Zirkel	9	0.008	0.1%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2	0.004	0.2%	Rocky_Mountain	9	0.002	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2	0.018	0.9%	Rocky_Mountain	9	0.007	0.1%	Mount_Evans
K	RGFO#2 -- West-Central/South	2	0.003	0.1%	Pecos	9	0.005	0.1%	Greenhorn_Mounta
L	RGFO#3 -- South	2	0.003	0.1%	Great_Sand_Dunes	9	0.023	0.3%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2	0.002	0.1%	Eagles_Nest	9	0.011	0.1%	Lost_Creek
N	New Mexico Farmington District	2	0.053	2.6%	Mesa_Verde	9	0.799	8.9%	Aztec_Ruins
O	Total Colorado River Field Office	2	0.027	1.3%	Flat_Tops	9	0.050	0.6%	Colorado
P	Total Royal Gorge Field Office	2	0.023	1.1%	Rocky_Mountain	9	0.023	0.3%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2	0.787	39.3%	Flat_Tops	9	1.075	11.9%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2	0.842	42.1%	Flat_Tops	9	1.191	13.2%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2	0.884	44.2%	Rocky_Mountain	9	1.248	13.9%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2	0.886	44.3%	Rocky_Mountain	9	1.249	13.9%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	2	1.164	58.2%	Rocky_Mountain	9	3.535	39.3%	Dinosaur_all
V	Natural Emissions	2	1224.900	61245.0%	Bandelier	9	481.211	5346.8%	Dome
W	2021 All Emissions	2	1228.190	61409.5%	Bandelier	9	486.073	5400.8%	Dome
X	2008 All Emissions	2	1227.070	61353.5%	Bandelier	9	485.583	5395.4%	Dome

Table 5-6b. Maximum 24-Hour PM_{2.5} concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	PM2.5, 24-hour	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2	0.004	0.2%	Mount_Zirkel	9	0.005	0.1%	Dinosaur_all
B	White River FO	2	0.026	1.3%	Flat_Tops	9	0.056	0.6%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2	0.011	0.6%	Flat_Tops	9	0.018	0.2%	Colorado
D	Roan Plateau Planning area portion of CRVFO	2	0.008	0.4%	Flat_Tops	9	0.013	0.1%	Colorado
E	Grand Junction FO	2	0.006	0.3%	Black_Canyon	9	0.014	0.2%	Colorado
F	Uncompahgre FO	2	0.021	1.0%	Maroon_Bells	9	0.020	0.2%	Raggeds
G	Tres Rios FO	2	0.041	2.0%	Mesa_Verde	9	0.034	0.4%	Hovenweep
H	Kremmling FO	2	0.001	0.1%	Mount_Zirkel	9	0.001	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2	0.001	0.0%	Rocky_Mountain	9	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2	0.004	0.2%	Rocky_Mountain	9	0.001	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2	0.000	0.0%	Pecos	9	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	2	0.002	0.1%	Great_Sand_Dunes	9	0.015	0.2%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2	0.000	0.0%	Eagles_Nest	9	0.002	0.0%	Lost_Creek
N	New Mexico Farmington District	2	0.053	2.6%	Mesa_Verde	9	0.800	8.9%	Aztec_Ruins
O	Total Colorado River Field Office	2	0.019	1.0%	Flat_Tops	9	0.031	0.3%	Colorado
P	Total Royal Gorge Field Office	2	0.005	0.2%	Rocky_Mountain	9	0.015	0.2%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2	0.787	39.4%	Flat_Tops	9	1.081	12.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2	0.804	40.2%	Flat_Tops	9	1.094	12.2%	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2	0.830	41.5%	Flat_Tops	9	1.110	12.3%	Raggeds
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2	0.835	41.7%	Flat_Tops	9	1.181	13.1%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	2	0.852	42.6%	Flat_Tops	9	3.524	39.2%	Dinosaur_all
V	Natural Emissions	2	1224.890	61244.5%	Bandelier	9	481.209	5346.8%	Dome
W	2021 All Emissions	2	1228.160	61408.0%	Bandelier	9	486.060	5400.7%	Dome
X	2008 All Emissions	2	1227.070	61353.5%	Bandelier	9	485.583	5395.4%	Dome

Table 5-6c. Maximum 24-Hour PM_{2.5} concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	PM2.5, 24-hour	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	2	0.027	1.4%	Mount_Zirkel	9	0.024	0.3%	Dinosaur_all
B	White River FO	2	0.132	6.6%	Flat_Tops	9	0.272	3.0%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	2	0.012	0.6%	Maroon_Bells	9	0.021	0.2%	Colorado
D	Roan Plateau Planning area portion of CRVFO	2	0.010	0.5%	Flat_Tops	9	0.020	0.2%	Colorado
E	Grand Junction FO	2	0.092	4.6%	Arches	9	0.207	2.3%	Colorado
F	Uncompahgre FO	2	0.039	1.9%	Maroon_Bells	9	0.041	0.5%	Raggeds
G	Tres Rios FO	2	0.186	9.3%	Mesa_Verde	9	0.188	2.1%	Hovenweep
H	Kremmling FO	2	0.007	0.3%	Eagles_Nest	9	0.005	0.1%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	2	0.002	0.1%	Rocky_Mountain	9	0.001	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	2	0.010	0.5%	Rocky_Mountain	9	0.004	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	2	0.002	0.1%	Pecos	9	0.004	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	2	0.002	0.1%	Great_Sand_Dunes	9	0.015	0.2%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	2	0.001	0.0%	Eagles_Nest	9	0.004	0.0%	Lost_Creek
N	New Mexico Farmington District	2	0.033	1.7%	Mesa_Verde	9	0.494	5.5%	Aztec_Ruins
O	Total Colorado River Field Office	2	0.022	1.1%	Eagles_Nest	9	0.042	0.5%	Colorado
P	Total Royal Gorge Field Office	2	0.013	0.6%	Rocky_Mountain	9	0.015	0.2%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	2	0.787	39.3%	Flat_Tops	9	1.076	12.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2	0.841	42.1%	Flat_Tops	9	1.175	13.1%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2	0.878	43.9%	Rocky_Mountain	9	1.231	13.7%	Dinosaur_all
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2	0.879	43.9%	Rocky_Mountain	9	1.232	13.7%	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	2	1.152	57.6%	Rocky_Mountain	9	3.533	39.3%	Dinosaur_all
V	Natural Emissions	2	1224.900	61245.0%	Bandelier	9	481.211	5346.8%	Dome
W	2021 All Emissions	2	1228.190	61409.5%	Bandelier	9	486.069	5400.8%	Dome
X	2008 All Emissions	2	1227.070	61353.5%	Bandelier	9	485.583	5395.4%	Dome

5.1.1.4 PM₁₀ PSD Concentrations

The results of the comparisons against the PM₁₀ PSD increments is very similar to PM_{2.5} with none of the Source Groups, except Natural Emissions (Source Group V) that are also included in the total 2021 and 2008 Source Groups, showing any exceedances of the annual or 24-hour PM₁₀ PSD increment (Tables 5-7 and 5-8). Wildfires within the Natural Emissions Source Group can produce very high PM concentrations.

Of the BLM Planning Areas, Federal O&G from the TRFO has the largest annual and 24-hour PM₁₀ concentrations at any Class I area with maximum values that of 12 and 16 percent for the High, 5 and 7 percent for the Medium and 1 and 2 percent for the Low Development Scenarios of the PSD PM₁₀ increment. The combined Source Groups R, S, T and U PM₁₀ impacts at any Class I area are 36% or less of the PM₁₀ PSD increments.

Table 5-7a. Maximum Annual PM₁₀ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	PM10, Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	4	0.004	0.1%	Mount_Zirkel	17	0.004	0.0%	Dinosaur_all
B	White River FO	4	0.034	0.8%	Flat_Tops	17	0.054	0.3%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	4	0.007	0.2%	Flat_Tops	17	0.003	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	4	0.004	0.1%	Flat_Tops	17	0.002	0.0%	Holy_Cross
E	Grand Junction FO	4	0.025	0.6%	Maroon_Bells	17	0.036	0.2%	Colorado
F	Uncompahgre FO	4	0.034	0.9%	Maroon_Bells	17	0.054	0.3%	Raggeds
G	Tres Rios FO	4	0.473	11.8%	Mesa_Verde	17	0.522	3.1%	South_San_Juan
H	Kremmling FO	4	0.015	0.4%	Rawah	17	0.005	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	4	0.000	0.0%	Rocky_Mountain	17	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	4	0.001	0.0%	Rocky_Mountain	17	0.001	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	4	0.000	0.0%	Pecos	17	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	4	0.000	0.0%	Great_Sand_Dunes	17	0.009	0.1%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	4	0.000	0.0%	Eagles_Nest	17	0.013	0.1%	Lost_Creek
N	New Mexico Farmington District	4	0.024	0.6%	Weminuche	17	0.900	5.3%	Aztec_Ruins
O	Total Colorado River Field Office	4	0.011	0.3%	Flat_Tops	17	0.005	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	4	0.002	0.0%	Rocky_Mountain	17	0.014	0.1%	Lost_Creek
Q	Mining from 13 Colorado BLM Planning Areas	4	0.164	4.1%	Mount_Zirkel	17	0.168	1.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	4	0.492	12.3%	Mesa_Verde	17	0.530	3.1%	South_San_Juan
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	4	1.058	26.4%	Mesa_Verde	17	1.077	6.3%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	4	1.071	26.8%	Mesa_Verde	17	1.330	7.8%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	4	1.108	27.7%	Mesa_Verde	17	1.796	10.6%	Aztec_Ruins
V	Natural Emissions	4	10.653	266.3%	Bandelier	17	5.251	30.9%	Sevilleta_NWR
W	2021 All Emissions	4	21.754	543.8%	Wheeler_Peak	17	65.725	386.6%	Valle_De_Oro_NWR
X	2008 All Emissions	4	17.449	436.2%	Bandelier	17	51.874	305.1%	Petroglyph

Table 5-7b. Maximum Annual PM₁₀ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	PM10, Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	4	0.001	0.0%	Mount_Zirkel	17	0.001	0.0%	Dinosaur_all
B	White River FO	4	0.006	0.1%	Flat_Tops	17	0.010	0.1%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	4	0.004	0.1%	Flat_Tops	17	0.002	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	4	0.002	0.1%	Flat_Tops	17	0.001	0.0%	Holy_Cross
E	Grand Junction FO	4	0.001	0.0%	Maroon_Bells	17	0.002	0.0%	Colorado
F	Uncompahgre FO	4	0.011	0.3%	Maroon_Bells	17	0.019	0.1%	Raggeds
G	Tres Rios FO	4	0.049	1.2%	Mesa_Verde	17	0.055	0.3%	South_San_Juan
H	Kremmling FO	4	0.002	0.0%	Rawah	17	0.000	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	4	0.000	0.0%	Rocky_Mountain	17	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	4	0.000	0.0%	Rocky_Mountain	17	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	4	0.000	0.0%	Pecos	17	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	4	0.000	0.0%	Great_Sand_Dunes	17	0.006	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	4	0.000	0.0%	Eagles_Nest	17	0.002	0.0%	Lost_Creek
N	New Mexico Farmington District	4	0.024	0.6%	Weminuche	17	0.900	5.3%	Aztec_Ruins
O	Total Colorado River Field Office	4	0.007	0.2%	Flat_Tops	17	0.003	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	4	0.000	0.0%	Rocky_Mountain	17	0.007	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	4	0.164	4.1%	Mount_Zirkel	17	0.168	1.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	4	0.169	4.2%	Mount_Zirkel	17	0.183	1.1%	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	4	0.688	17.2%	Mesa_Verde	17	0.672	4.0%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	4	0.701	17.5%	Mesa_Verde	17	1.315	7.7%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	4	0.738	18.5%	Mesa_Verde	17	1.781	10.5%	Aztec_Ruins
V	Natural Emissions	4	10.653	266.3%	Bandelier	17	5.251	30.9%	Sevilleta_NWR
W	2021 All Emissions	4	21.747	543.7%	Wheeler_Peak	17	65.719	386.6%	Valle_De_Oro_NWR
X	2008 All Emissions	4	17.449	436.2%	Bandelier	17	51.874	305.1%	Petroglyph

Table 5-7c. Maximum Annual PM₁₀ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	PM10, Annual	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	4	0.003	0.1%	Mount_Zirkel	17	0.003	0.0%	Dinosaur_all
B	White River FO	4	0.023	0.6%	Flat_Tops	17	0.047	0.3%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	4	0.004	0.1%	Flat_Tops	17	0.002	0.0%	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	4	0.003	0.1%	Flat_Tops	17	0.002	0.0%	Holy_Cross
E	Grand Junction FO	4	0.014	0.3%	Maroon_Bells	17	0.025	0.1%	Colorado
F	Uncompahgre FO	4	0.017	0.4%	Maroon_Bells	17	0.027	0.2%	Raggeds
G	Tres Rios FO	4	0.203	5.1%	Mesa_Verde	17	0.222	1.3%	South_San_Juan
H	Kremmling FO	4	0.007	0.2%	Rawah	17	0.002	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	4	0.000	0.0%	Rocky_Mountain	17	0.000	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	4	0.000	0.0%	Rocky_Mountain	17	0.000	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	4	0.000	0.0%	Pecos	17	0.000	0.0%	Maxwell_NWR
L	RGFO#3 -- South	4	0.000	0.0%	Great_Sand_Dunes	17	0.004	0.0%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	4	0.000	0.0%	Eagles_Nest	17	0.003	0.0%	Lost_Creek
N	New Mexico Farmington District	4	0.011	0.3%	Weminuche	17	0.380	2.2%	Aztec_Ruins
O	Total Colorado River Field Office	4	0.007	0.2%	Flat_Tops	17	0.004	0.0%	Holy_Cross
P	Total Royal Gorge Field Office	4	0.001	0.0%	Rocky_Mountain	17	0.004	0.0%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	4	0.164	4.1%	Mount_Zirkel	17	0.168	1.0%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	4	0.219	5.5%	Mesa_Verde	17	0.229	1.3%	South_San_Juan
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	4	0.776	19.4%	Mesa_Verde	17	0.772	4.5%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	4	0.782	19.6%	Mesa_Verde	17	0.786	4.6%	South_San_Juan
U	Combined O&G and Mining in 4 km domain	4	0.819	20.5%	Mesa_Verde	17	1.241	7.3%	Aztec_Ruins
V	Natural Emissions	4	10.653	266.3%	Bandelier	17	5.251	30.9%	Sevilleta_NWR
W	2021 All Emissions	4	21.748	543.7%	Wheeler_Peak	17	65.722	386.6%	Valle_De_Oro_NWR
X	2008 All Emissions	4	17.449	436.2%	Bandelier	17	51.874	305.1%	Petroglyph

Table 5-8a. Maximum 24-Hour PM₁₀ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 High Development Scenario.

Choose	PM10, 24-hour	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	8	0.036	0.4%	Mount_Zirkel	30	0.042	0.1%	Dinosaur_all
B	White River FO	8	0.161	2.0%	Flat_Tops	30	0.327	1.1%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	8	0.029	0.4%	Flat_Tops	30	0.031	0.1%	Colorado
D	Roan Plateau Planning area portion of CRVFO	8	0.019	0.2%	Flat_Tops	30	0.027	0.1%	Colorado
E	Grand Junction FO	8	0.130	1.6%	Arches	30	0.295	1.0%	Colorado
F	Uncompahgre FO	8	0.160	2.0%	Maroon_Bells	30	0.168	0.6%	Raggeds
G	Tres Rios FO	8	1.249	15.6%	Mesa_Verde	30	1.160	3.9%	South_San_Juan
H	Kremmling FO	8	0.038	0.5%	Rawah	30	0.020	0.1%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	8	0.009	0.1%	Rocky_Mountain	30	0.003	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	8	0.035	0.4%	Rocky_Mountain	30	0.012	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	8	0.003	0.0%	Pecos	30	0.005	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	8	0.004	0.1%	Great_Sand_Dunes	30	0.035	0.1%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	8	0.006	0.1%	Eagles_Nest	30	0.053	0.2%	Lost_Creek
N	New Mexico Farmington District	8	0.176	2.2%	Mesa_Verde	30	2.778	9.3%	Aztec_Ruins
O	Total Colorado River Field Office	8	0.049	0.6%	Flat_Tops	30	0.058	0.2%	Colorado
P	Total Royal Gorge Field Office	8	0.044	0.6%	Rocky_Mountain	30	0.053	0.2%	Lost_Creek
Q	Mining from 13 Colorado BLM Planning Areas	8	0.787	9.8%	Flat_Tops	30	1.075	3.6%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	8	1.284	16.1%	Mesa_Verde	30	1.234	4.1%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	8	2.746	34.3%	Mesa_Verde	30	2.372	7.9%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	8	2.773	34.7%	Mesa_Verde	30	4.063	13.5%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	8	2.880	36.0%	Mesa_Verde	30	6.475	21.6%	Aztec_Ruins
V	Natural Emissions	8	1310.760	16384.5%	Bandelier	30	512.681	1708.9%	Dome
W	2021 All Emissions	8	1318.400	16480.0%	Bandelier	30	522.924	1743.1%	Dome
X	2008 All Emissions	8	1314.400	16430.0%	Bandelier	30	520.280	1734.3%	Dome

Table 5-8b. Maximum 24-Hour PM₁₀ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Low Development Scenario.

Choose	PM10, 24-hour	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	8	0.005	0.1%	Mount_Zirkel	30	0.006	0.0%	Dinosaur_all
B	White River FO	8	0.029	0.4%	Flat_Tops	30	0.062	0.2%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	8	0.020	0.3%	Flat_Tops	30	0.022	0.1%	Colorado
D	Roan Plateau Planning area portion of CRVFO	8	0.011	0.1%	Flat_Tops	30	0.015	0.1%	Colorado
E	Grand Junction FO	8	0.007	0.1%	Black_Canyon	30	0.017	0.1%	Colorado
F	Uncompahgre FO	8	0.056	0.7%	Maroon_Bells	30	0.054	0.2%	Raggeds
G	Tres Rios FO	8	0.133	1.7%	Mesa_Verde	30	0.121	0.4%	South_San_Juan
H	Kremmling FO	8	0.004	0.0%	Rawah	30	0.002	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	8	0.002	0.0%	Rocky_Mountain	30	0.001	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	8	0.007	0.1%	Rocky_Mountain	30	0.002	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	8	0.000	0.0%	Pecos	30	0.000	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	8	0.003	0.0%	Great_Sand_Dunes	30	0.023	0.1%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	8	0.001	0.0%	Eagles_Nest	30	0.008	0.0%	Lost_Creek
N	New Mexico Farmington District	8	0.176	2.2%	Mesa_Verde	30	2.778	9.3%	Aztec_Ruins
O	Total Colorado River Field Office	8	0.031	0.4%	Flat_Tops	30	0.038	0.1%	Colorado
P	Total Royal Gorge Field Office	8	0.009	0.1%	Rocky_Mountain	30	0.023	0.1%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	8	0.787	9.8%	Flat_Tops	30	1.081	3.6%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	8	0.808	10.1%	Flat_Tops	30	1.114	3.7%	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	8	1.788	22.3%	Mesa_Verde	30	1.483	4.9%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	8	1.815	22.7%	Mesa_Verde	30	4.038	13.5%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	8	1.925	24.1%	Mesa_Verde	30	6.458	21.5%	Aztec_Ruins
V	Natural Emissions	8	1310.760	16384.5%	Bandelier	30	512.679	1708.9%	Dome
W	2021 All Emissions	8	1318.360	16479.5%	Bandelier	30	522.909	1743.0%	Dome
X	2008 All Emissions	8	1314.400	16430.0%	Bandelier	30	520.280	1734.3%	Dome

Table 5-8c. Maximum 24-Hour PM₁₀ concentration at any Class I or sensitive Class II area due to the different Source Groups for the 2021 Medium Development Scenario.

Choose	PM10, 24-hour	µg/m3							
Across grid cells	Maximum								
Group	Group Name	PSD Class I Increment	Max @ any Class I area	Percent of PSD Class I Increment	Class I Area where Max occurred	PSD Class II Increment	Max @ any Class II area	Percent of PSD Class II Increment	Class II Area where Max occurred
A	Little Snake FO	8	0.029	0.4%	Mount_Zirkel	30	0.029	0.1%	Dinosaur_all
B	White River FO	8	0.132	1.7%	Flat_Tops	30	0.286	1.0%	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	8	0.017	0.2%	Flat_Tops	30	0.023	0.1%	Colorado
D	Roan Plateau Planning area portion of CRVFO	8	0.012	0.2%	Flat_Tops	30	0.022	0.1%	Colorado
E	Grand Junction FO	8	0.096	1.2%	Arches	30	0.223	0.7%	Colorado
F	Uncompahgre FO	8	0.079	1.0%	Maroon_Bells	30	0.081	0.3%	Raggeds
G	Tres Rios FO	8	0.561	7.0%	Mesa_Verde	30	0.492	1.6%	South_San_Juan
H	Kremmling FO	8	0.017	0.2%	Rawah	30	0.010	0.0%	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	8	0.003	0.0%	Rocky_Mountain	30	0.001	0.0%	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	8	0.014	0.2%	Rocky_Mountain	30	0.005	0.0%	Mount_Evans
K	RGFO#2 -- West-Central/South	8	0.002	0.0%	Pecos	30	0.004	0.0%	Greenhorn_Mounta
L	RGFO#3 -- South	8	0.002	0.0%	Great_Sand_Dunes	30	0.018	0.1%	Greenhorn_Mounta
M	RGFO#4 -- East-Central	8	0.001	0.0%	Eagles_Nest	30	0.012	0.0%	Lost_Creek
N	New Mexico Farmington District	8	0.077	1.0%	Mesa_Verde	30	1.234	4.1%	Aztec_Ruins
O	Total Colorado River Field Office	8	0.028	0.4%	Flat_Tops	30	0.045	0.2%	Colorado
P	Total Royal Gorge Field Office	8	0.017	0.2%	Rocky_Mountain	30	0.019	0.1%	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	8	0.787	9.8%	Flat_Tops	30	1.076	3.6%	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	8	0.842	10.5%	Flat_Tops	30	1.192	4.0%	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	8	2.028	25.3%	Mesa_Verde	30	1.706	5.7%	South_San_Juan
T	Cumulative Emissions Scenario -- New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	8	2.042	25.5%	Mesa_Verde	30	2.405	8.0%	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	8	2.150	26.9%	Mesa_Verde	30	4.742	15.8%	Aztec_Ruins
V	Natural Emissions	8	1310.760	16384.5%	Bandelier	30	512.681	1708.9%	Dome
W	2021 All Emissions	8	1318.390	16479.9%	Bandelier	30	522.916	1743.1%	Dome
X	2008 All Emissions	8	1314.400	16430.0%	Bandelier	30	520.280	1734.3%	Dome

5.1.2 PSD Concentration across All Class I and Sensitive Class II Areas

In this section we present examples of the contributions of PSD pollutant concentrations across all PSD Class I and sensitive Class II areas for the BLM GJFO Planning Areas as well as several of the combined Planning Area Source Groups. The tables below were obtained from the “Summary” sheet of Attachments A-1, A-2 and A-3 Excel spreadsheet that contains results for all of the Source Groups.

5.1.2.1 Individual BLM Planning Area PSD Contributions

Table 5-9 displays the contributions of new oil and gas emissions on Federal lands to PSD pollutant concentrations at all Class I and sensitive Class II areas in the CARMMS 4 km domain for the BLM Grand Junction Field Office (GJFO) Planning Area. All of the PSD pollutant concentrations at Class I areas due to new O&G on Federal lands within the BLM GJFO Planning Area (as well as the other 14 BLM other Planning Areas) are well below the Class I and II PSD concentration increments. Similar Tables of concentrations contributions at all of the Class I and sensitive Class II areas from each of the 24 Source Groups and the High and Low Development Scenarios can be found in Attachments A-1, A-2 and A-3.

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Table 5-9b. Contributions of new oil and gas emissions on Federal lands within the BLM Grand Junction Field Office Planning Area to PSD pollutant concentrations at Class I and sensitive Class II areas for the 2021 Low Development Scenario.

Group	G E		Grand Junction FO									
Across grid cells	Maximum		Max									
			Pollutant		NO ₂ (µg/m ³)		PM ₁₀ (µg/m ³)		PM _{2.5} (µg/m ³)		SO ₂ (µg/m ³)	
			Averaging Time		Annual ¹	24-hour ²	Annual ³	24-hour ²	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	2.5	8	4	2	1	25	5	2		
PSD Class I Increment ¹												
Arches NP	UT	NPS	0.004	0.007	0.001	0.006	0.001	0.000	0.000	0.000	0.000	0.000
Bandelier NM	NM	NPS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Black Canyon of the Gunnison NM	CO	NPS	0.002	0.007	0.001	0.006	0.000	0.000	0.000	0.000	0.000	0.000
Bosque del Apache Wilderness	NM	FWS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Canyonlands NP	UT	NPS	0.001	0.004	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000
Capitol Reef NP	UT	NPS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Eagles Nest Wilderness	CO	FS	0.002	0.005	0.001	0.004	0.001	0.000	0.000	0.000	0.000	0.000
Flat Tops Wilderness	CO	FS	0.004	0.004	0.001	0.003	0.001	0.000	0.000	0.000	0.000	0.000
Galluro Wilderness	AZ	FS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gila Wilderness	NM	FS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Great Sand Dunes NM	CO	NPS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
La Garita Wilderness	CO	FS	0.000	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Maroon Bells-Snowmass Wilderness	CO	FS	0.004	0.007	0.001	0.005	0.001	0.000	0.000	0.000	0.000	0.000
Mesa Verde NP	CO	NPS	0.000	0.002	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Mount Baldy Wilderness	AZ	FS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mount Zirkel Wilderness	CO	FS	0.001	0.002	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Pecos Wilderness	NM	FS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Petrified Forest NP	AZ	NPS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Rawah Wilderness	CO	FS	0.001	0.002	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Rocky Mountain NP	CO	NPS	0.001	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Salt Creek Wilderness	NM	FWS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
San Pedro Parks Wilderness	NM	FS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Weminuche Wilderness	CO	FS	0.000	0.002	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
West Elk Wilderness	CO	FS	0.002	0.005	0.001	0.004	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Peak Wilderness	NM	FS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
White Mountain Wilderness	NM	FS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Dinosaur NM ²	CO	NPS	NA	NA	NA	NA	NA	0.000	0.000	0.000	0.000	0.000
Class II	State	Owner	PSD Class II Increment ¹									
			25	30	17	9	4	512	91	20		
Alamosa NWR	CO	FWS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Aldo Leopold Wilderness	NM	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Apache Kid Wilderness	NM	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Aztec Ruins NM	NM	NPS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Baca NWR	CO	FWS	0.000	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Bear Wallow Wilderness	AZ	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bitter Lake NWR	NM	FWS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Blue Range Wilderness	NM	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bosque Del Apache NWR	NM	FWS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Browns Park NWR	CO	FWS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Canyon de Chelly NM	AZ	NPS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Capitan Mountains Wilderness	NM	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Chaco Culture NHP	NM	NPS	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Chama River Canyon Wilderness	NM	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Chimney Rock NM	CO	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Colorado NM	CO	NPS	0.008	0.017	0.002	0.014	0.001	0.000	0.000	0.000	0.000	0.000
Cruces Basin Wilderness	NM	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Curecanti NRA	CO	NPS	0.001	0.005	0.001	0.004	0.000	0.000	0.000	0.000	0.000	0.000
Dark Canyon Wilderness	UT	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Dinosaur NM	CO	NPS	0.001	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Dome Wilderness	NM	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
El Malpais NM	NM	NPS	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Escudilla Wilderness	AZ	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Flaming Gorge	UT	USFS	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Florissant Fossil Beds NM	CO	NPS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Fossil Ridge Wilderness	CO	USFS	0.001	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Glen Canyon NRA	UT	NPS	0.000	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Great Sand Dunes National Park	CO	NPS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Great Sand Dunes National Preserve	CO	NPS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Greenhorn Mountain Wilderness	CO	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
High Uintas Wilderness	UT	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Holy Cross Wilderness	CO	USFS	0.002	0.005	0.001	0.004	0.001	0.000	0.000	0.000	0.000	0.000
Hovenweep NM	CO	NPS	0.000	0.002	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Hunter-Fryingpan Wilderness	CO	USFS	0.002	0.005	0.001	0.004	0.000	0.000	0.000	0.000	0.000	0.000
Las Vegas NWR	NM	FWS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Latir Peak Wilderness	NM	USFS	0.000	0.002	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Lizard Head Wilderness	CO	USFS	0.000	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Lost Creek Wilderness	CO	USFS	0.001	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Manzano Mountain Wilderness	NM	USFS	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Maxwell NWR	NM	FWS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Monte Vista NWR	CO	FWS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Mount Evans Wilderness	CO	USFS	0.001	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Mount Sneffels Wilderness	CO	USFS	0.001	0.003	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000
Natural Bridges NM	UT	NPS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Navajo NM	AZ	NPS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Petroglyph NM	NM	NPS	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Powderhorn Wilderness	CO	USFS	0.000	0.003	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Raggeds Wilderness	CO	USFS	0.003	0.006	0.001	0.004	0.001	0.000	0.000	0.000	0.000	0.000
Rio Mora NWR and CA	NM	FWS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Sandia Mountain Wilderness	NM	USFS	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sangre de Cristo Wilderness	CO	USFS	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
Savage Run Wilderness	WY	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Sevilleta NWR	NM	FWS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
South San Juan Wilderness	CO	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Spanish Peaks Wilderness	CO	USFS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Uncompahgre Wilderness	CO	USFS	0.000	0.003	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000
Valle De Oro NWR	NM	FWS	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Withington Wilderness	NM	USFS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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5.1.2.2 Combined BLM Planning Area PSD Contributions

Below we examine the contributions of emissions to concentrations at Class I areas for three of the combination Source Groups: (R) Federal O&G and mining within the 13 Colorado BLM Planning Areas; (T) the Cumulative Emissions Scenario that includes new O&G and mining on Federal lands and new O&G on non-Federal lands within the 14 NM BLM Planning Areas; and (U) all O&G (new Federal and non-Federal and existing) throughout the 4 km CARMMS domain plus Federal mining. Results for the other Source Groups as well as results for the sensitive Class II areas are contained in Attachments A-1, A-2 and A-3.

Source Group R represents mining and new O&G development on Federal lands within the 13 Colorado BLM Planning Areas so represents potential new emissions that may be mitigated by the BLM COSO. The PSD contributions of Source Group R are below the Class I and Class II PSD increments at all Class I and sensitive Class II areas, respectively, for all PSD pollutants and averaging times and the 2021 High, Low and Medium Scenarios (Table 5-10). As a percentage of a PSD increment, the largest contribution at any Class I area due to Source Group R is 79% ($1.979 \mu\text{g}/\text{m}^3$), 10% ($0.239 \mu\text{g}/\text{m}^3$) and 67% ($1.669 \mu\text{g}/\text{m}^3$) of the $2.5 \mu\text{g}/\text{m}^3$ annual NO_2 PSD Class I increment for the, respectively, High, Low and Medium Development Scenarios and occurs at the Mesa Verde National Park. These NO_2 impacts are primarily (99%) due to new Federal O&G emissions from the TRFO Planning Area.

Source Group T is the Cumulative Emissions Scenario that includes new Federal and non-Federal oil and gas and Federal mining within the 14 BLM Colorado and Northern New Mexico Planning Areas whose PSD pollutant concentrations for the 2021 High and Low Development Scenarios are shown in Table 5-11. With one exception, the contribution of the Cumulative Emissions Scenario to PSD concentrations at all Class I and sensitive Class II areas are below the PSD Class I and II concentrations increments. The exception is for annual NO_2 at the Mesa Verde Class I area where the 2021 High, Low and Medium Development Scenario estimate an annual NO_2 contributions of, respectively, 4.50, 4.11 and $2.87 \mu\text{g}/\text{m}^3$ that exceed the $2.5 \mu\text{g}/\text{m}^3$ annual NO_2 PSD Class I area increment. Note that new Federal O&G emissions from the TRFO Planning Area contributed $1.97 \mu\text{g}/\text{m}^3$ (High Scenario), $0.24 \mu\text{g}/\text{m}^3$ (Low Scenario) and $1.66 \mu\text{g}/\text{m}^3$ (Medium Scenario) to the maximum annual NO_2 at Mesa Verde and the split between new Federal and non-Federal O&G in the TRFO planning Area is 40% and 60%, respectively (see Table 3-2). Thus, the Cumulative Emissions Source Group T annual NO_2 contribution at Mesa Verde is mainly due to new Federal and non-Federal O&G development within the TRFO Planning Area.

The contributions of all O&G within the 4 km CARMMS domain plus Federal mining in Colorado (Source Group U) to PSD pollutants at Class I areas for the two 2021 emission scenarios are shown in Table 5-12. Again, with one exception, the contributions of all O&G emissions throughout the 4 km CARMMS domain produce PSD pollutant concentrations at all Class I and sensitive Class II areas that are below the PSD Class I and II area increments, respectively. The exception is the annual NO_2 at Mesa Verde Class I area where Source Group U contributes 4.78, 3.15 and $4.38 \mu\text{g}/\text{m}^3$ for the High, Low and Medium Development Scenarios, respectively.

Table 5-10a. Contributions of new oil and gas and mining on Federal lands within the 13 Colorado BLM Planning Areas to PSD pollutant concentrations at Class I areas (Source Group R) for the 2021 High Development Scenario.

Group		G_R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas							
Across grid cells		Maximum	Max							
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)	PM ₂₅ (µg/m ³)	SO ₂ (µg/m ³)			
		Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ²	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹							
			2.5	8	4	2	1	25	5	2
Arches NP	UT	NPS	0.117	0.248	0.040	0.213	0.033	0.087	0.037	0.003
Bandelier NM	NM	NPS	0.006	0.080	0.009	0.069	0.006	0.011	0.005	0.000
Black Canyon of the Gunnison NM	CO	NPS	0.064	0.380	0.057	0.327	0.046	0.071	0.043	0.004
Bosque del Apache Wilderness	NM	FWS	0.002	0.047	0.003	0.036	0.002	0.010	0.004	0.000
Canyonlands NP	UT	NPS	0.037	0.177	0.019	0.138	0.014	0.062	0.026	0.002
Capitol Reef NP	UT	NPS	0.003	0.060	0.003	0.047	0.003	0.021	0.007	0.000
Eagles Nest Wilderness	CO	FS	0.091	0.244	0.072	0.202	0.057	0.076	0.022	0.003
Flat Tops Wilderness	CO	FS	0.225	0.844	0.160	0.842	0.133	0.356	0.132	0.013
Galiuro Wilderness	AZ	FS	0.000	0.006	0.000	0.005	0.000	0.002	0.000	0.000
Gila Wilderness	NM	FS	0.001	0.025	0.001	0.020	0.001	0.009	0.003	0.000
Great Sand Dunes NM	CO	NPS	0.015	0.128	0.023	0.111	0.019	0.023	0.009	0.001
La Garita Wilderness	CO	FS	0.019	0.147	0.022	0.116	0.017	0.045	0.014	0.001
Maroon Bells-Snowmass Wilderness	CO	FS	0.202	0.534	0.157	0.442	0.118	0.096	0.030	0.005
Mesa Verde NP	CO	NPS	1.979	1.284	0.492	0.339	0.104	0.047	0.018	0.002
Mount Baldy Wilderness	AZ	FS	0.000	0.030	0.001	0.026	0.001	0.005	0.002	0.000
Mount Zirkel Wilderness	CO	FS	0.092	0.753	0.190	0.741	0.182	0.150	0.054	0.008
Pecos Wilderness	NM	FS	0.005	0.064	0.008	0.054	0.006	0.014	0.005	0.000
Petrified Forest NP	AZ	NPS	0.001	0.039	0.002	0.034	0.002	0.007	0.003	0.000
Rawah Wilderness	CO	FS	0.076	0.344	0.084	0.314	0.068	0.080	0.024	0.004
Rocky Mountain NP	CO	NPS	0.053	0.297	0.075	0.282	0.066	0.072	0.017	0.003
Salt Creek Wilderness	NM	FWS	0.001	0.038	0.002	0.032	0.002	0.005	0.002	0.000
San Pedro Parks Wilderness	NM	FS	0.008	0.077	0.009	0.057	0.006	0.019	0.007	0.000
Weminuche Wilderness	CO	FS	0.019	0.111	0.017	0.088	0.013	0.051	0.014	0.001
West Elk Wilderness	CO	FS	0.121	0.678	0.172	0.659	0.151	0.079	0.031	0.003
Wheeler Peak Wilderness	NM	FS	0.006	0.077	0.011	0.065	0.008	0.019	0.006	0.001
White Mountain Wilderness	NM	FS	0.001	0.028	0.002	0.022	0.002	0.008	0.003	0.000
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	1.262	0.412	0.090

Table 5-10b. Contributions of new oil and gas and mining on Federal lands within the 13 Colorado BLM Planning Areas to PSD pollutant concentrations at Class I areas (Source Group R) for the 2021 Low Development Scenario.

Group		G_R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas							
Across grid cells		Maximum	Max							
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)	PM ₂₅ (µg/m ³)	SO ₂ (µg/m ³)			
		Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ²	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹							
			2.5	8	4	2	1	25	5	2
Arches NP	UT	NPS	0.017	0.141	0.020	0.131	0.019	0.014	0.005	0.001
Bandelier NM	NM	NPS	0.001	0.038	0.004	0.037	0.004	0.002	0.001	0.000
Black Canyon of the Gunnison NM	CO	NPS	0.010	0.211	0.031	0.204	0.030	0.011	0.006	0.001
Bosque del Apache Wilderness	NM	FWS	0.000	0.028	0.002	0.027	0.001	0.002	0.001	0.000
Canyonlands NP	UT	NPS	0.006	0.107	0.009	0.102	0.009	0.009	0.004	0.000
Capitol Reef NP	UT	NPS	0.000	0.039	0.002	0.037	0.002	0.004	0.001	0.000
Eagles Nest Wilderness	CO	FS	0.020	0.149	0.043	0.148	0.041	0.011	0.003	0.001
Flat Tops Wilderness	CO	FS	0.051	0.808	0.110	0.804	0.105	0.053	0.021	0.002
Galiuro Wilderness	AZ	FS	0.000	0.003	0.000	0.003	0.000	0.000	0.000	0.000
Gila Wilderness	NM	FS	0.000	0.016	0.001	0.015	0.001	0.001	0.001	0.000
Great Sand Dunes NM	CO	NPS	0.004	0.066	0.011	0.063	0.011	0.004	0.002	0.000
La Garita Wilderness	CO	FS	0.004	0.110	0.011	0.108	0.011	0.007	0.002	0.000
Maroon Bells-Snowmass Wilderness	CO	FS	0.054	0.380	0.105	0.356	0.095	0.014	0.005	0.001
Mesa Verde NP	CO	NPS	0.239	0.160	0.063	0.130	0.031	0.007	0.003	0.000
Mount Baldy Wilderness	AZ	FS	0.000	0.012	0.001	0.012	0.000	0.001	0.000	0.000
Mount Zirkel Wilderness	CO	FS	0.022	0.714	0.169	0.712	0.167	0.022	0.008	0.001
Pecos Wilderness	NM	FS	0.001	0.035	0.004	0.034	0.004	0.002	0.001	0.000
Petrified Forest NP	AZ	NPS	0.000	0.022	0.001	0.022	0.001	0.001	0.001	0.000
Rawah Wilderness	CO	FS	0.013	0.303	0.057	0.300	0.056	0.013	0.004	0.001
Rocky Mountain NP	CO	NPS	0.011	0.257	0.054	0.256	0.053	0.012	0.003	0.001
Salt Creek Wilderness	NM	FWS	0.000	0.020	0.001	0.020	0.001	0.001	0.000	0.000
San Pedro Parks Wilderness	NM	FS	0.001	0.040	0.004	0.037	0.004	0.003	0.001	0.000
Weminuche Wilderness	CO	FS	0.003	0.080	0.008	0.076	0.008	0.007	0.002	0.000
West Elk Wilderness	CO	FS	0.034	0.646	0.139	0.642	0.134	0.011	0.005	0.001
Wheeler Peak Wilderness	NM	FS	0.001	0.046	0.006	0.044	0.005	0.003	0.001	0.000
White Mountain Wilderness	NM	FS	0.000	0.020	0.001	0.019	0.001	0.001	0.000	0.000
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	0.189	0.067	0.014

Table 5-10c. Contributions of new oil and gas and mining on Federal lands within the 13 Colorado BLM Planning Areas to PSD pollutant concentrations at Class I areas (Source Group R) for the 2021 Medium Development Scenario.

Group		G_R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas								
Across grid cells		Maximum	Max								
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)		PM ₂₅ (µg/m ³)		SO ₂ (µg/m ³)		
			Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹								
			2.5	8	4	2	1	25	5	2	
Arches NP	UT	NPS	0.111	0.212	0.034	0.197	0.031	0.087	0.037	0.003	
Bandelier NM	NM	NPS	0.005	0.066	0.007	0.062	0.006	0.011	0.005	0.000	
Black Canyon of the Gunnison NM	CO	NPS	0.056	0.321	0.047	0.300	0.042	0.071	0.043	0.004	
Bosque del Apache Wilderness	NM	FWS	0.001	0.036	0.002	0.032	0.002	0.010	0.004	0.000	
Canyonlands NP	UT	NPS	0.033	0.143	0.015	0.128	0.013	0.062	0.026	0.002	
Capitol Reef NP	UT	NPS	0.002	0.049	0.003	0.044	0.002	0.021	0.007	0.000	
Eagles Nest Wilderness	CO	FS	0.078	0.194	0.059	0.183	0.053	0.076	0.022	0.003	
Flat Tops Wilderness	CO	FS	0.176	0.842	0.137	0.841	0.126	0.356	0.132	0.013	
Galiuro Wilderness	AZ	FS	0.000	0.005	0.000	0.004	0.000	0.002	0.000	0.000	
Gila Wilderness	NM	FS	0.001	0.021	0.001	0.018	0.001	0.009	0.003	0.000	
Great Sand Dunes NM	CO	NPS	0.012	0.103	0.018	0.097	0.017	0.023	0.009	0.001	
La Garita Wilderness	CO	FS	0.016	0.117	0.018	0.113	0.016	0.045	0.014	0.001	
Maroon Bells-Snowmass Wilderness	CO	FS	0.150	0.454	0.126	0.414	0.110	0.096	0.030	0.005	
Mesa Verde NP	CO	NPS	1.669	0.597	0.219	0.221	0.064	0.047	0.018	0.002	
Mount Baldy Wilderness	AZ	FS	0.000	0.025	0.001	0.024	0.001	0.005	0.002	0.000	
Mount Zirkel Wilderness	CO	FS	0.079	0.743	0.182	0.739	0.179	0.150	0.053	0.008	
Pecos Wilderness	NM	FS	0.005	0.052	0.006	0.048	0.005	0.014	0.005	0.000	
Petrified Forest NP	AZ	NPS	0.001	0.034	0.002	0.032	0.002	0.007	0.003	0.000	
Rawah Wilderness	CO	FS	0.056	0.318	0.071	0.310	0.065	0.080	0.024	0.004	
Rocky Mountain NP	CO	NPS	0.043	0.279	0.066	0.272	0.063	0.072	0.017	0.003	
Salt Creek Wilderness	NM	FWS	0.001	0.031	0.002	0.029	0.002	0.005	0.002	0.000	
San Pedro Parks Wilderness	NM	FS	0.007	0.058	0.007	0.050	0.005	0.019	0.007	0.000	
Weminuche Wilderness	CO	FS	0.017	0.093	0.013	0.084	0.011	0.051	0.014	0.001	
West Elk Wilderness	CO	FS	0.094	0.662	0.154	0.654	0.146	0.079	0.031	0.003	
Wheeler Peak Wilderness	NM	FS	0.005	0.064	0.008	0.060	0.007	0.019	0.006	0.001	
White Mountain Wilderness	NM	FS	0.001	0.023	0.002	0.021	0.002	0.007	0.003	0.000	
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	1.262	0.412	0.090	

Table 5-11a. Contributions of new oil and gas and mining on Federal lands and new oil and gas on non-Federal lands within the 14 BLM Planning Areas to PSD pollutant concentrations at Class I and sensitive Class II areas (Source Group T) for the 2021 High Development Scenario.

Group	G_T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas									
Across grid cells	Maximum	Max									
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)		PM _{2.5} (µg/m ³)		SO ₂ (µg/m ³)		
			Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹								
			2.5	8	4	2	1	25	5	2	
Arches NP	UT	NPS	0.233	0.443	0.063	0.345	0.049	0.103	0.044	0.004	
Bandelier NM	NM	NPS	0.028	0.200	0.027	0.138	0.014	0.013	0.006	0.000	
Black Canyon of the Gunnison NM	CO	NPS	0.424	0.691	0.171	0.511	0.078	0.083	0.050	0.004	
Bosque del Apache Wilderness	NM	FWS	0.004	0.083	0.007	0.051	0.004	0.012	0.004	0.000	
Canyonlands NP	UT	NPS	0.069	0.249	0.032	0.178	0.021	0.072	0.031	0.002	
Capitol Reef NP	UT	NPS	0.011	0.090	0.009	0.069	0.005	0.025	0.009	0.000	
Eagles Nest Wilderness	CO	FS	0.185	0.391	0.105	0.312	0.077	0.088	0.026	0.004	
Flat Tops Wilderness	CO	FS	0.387	0.974	0.201	0.856	0.156	0.405	0.150	0.015	
Galiuro Wilderness	AZ	FS	0.000	0.022	0.000	0.010	0.000	0.002	0.001	0.000	
Gila Wilderness	NM	FS	0.001	0.039	0.002	0.031	0.002	0.011	0.004	0.000	
Great Sand Dunes NM	CO	NPS	0.037	0.218	0.047	0.187	0.033	0.027	0.011	0.001	
La Garita Wilderness	CO	FS	0.044	0.240	0.038	0.179	0.026	0.052	0.016	0.002	
Maroon Bells-Snowmass Wilderness	CO	FS	0.377	0.709	0.214	0.528	0.144	0.110	0.034	0.006	
Mesa Verde NP	CO	NPS	4.498	2.773	1.071	0.726	0.220	0.054	0.021	0.004	
Mount Baldy Wilderness	AZ	FS	0.001	0.045	0.002	0.039	0.001	0.006	0.002	0.000	
Mount Zirkel Wilderness	CO	FS	0.154	0.800	0.212	0.758	0.194	0.173	0.061	0.009	
Pecos Wilderness	NM	FS	0.025	0.144	0.024	0.102	0.012	0.017	0.006	0.001	
Petrified Forest NP	AZ	NPS	0.004	0.076	0.005	0.048	0.003	0.009	0.004	0.000	
Rawah Wilderness	CO	FS	0.141	0.410	0.117	0.328	0.082	0.091	0.028	0.004	
Rocky Mountain NP	CO	NPS	0.187	1.612	0.183	0.886	0.094	0.083	0.020	0.004	
Salt Creek Wilderness	NM	FWS	0.004	0.068	0.007	0.048	0.004	0.005	0.003	0.000	
San Pedro Parks Wilderness	NM	FS	0.038	0.201	0.029	0.095	0.013	0.023	0.009	0.001	
Weminuche Wilderness	CO	FS	0.081	0.199	0.056	0.128	0.025	0.059	0.017	0.001	
West Elk Wilderness	CO	FS	0.234	0.736	0.214	0.684	0.172	0.091	0.036	0.004	
Wheeler Peak Wilderness	NM	FS	0.025	0.127	0.028	0.095	0.016	0.022	0.007	0.001	
White Mountain Wilderness	NM	FS	0.003	0.059	0.005	0.036	0.003	0.009	0.003	0.000	
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	1.435	0.469	0.102	

Table 5-11b. Contributions of new oil and gas and mining on Federal lands and new oil and gas on non-Federal lands within the 14 BLM Planning Areas to PSD pollutant concentrations at Class I and sensitive Class II areas (Source Group T) for the 2021 Low Development Scenario.

Group		G, T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Area							
Across grid cells		Maximum	Max							
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)	PM _{2.5} (µg/m ³)	SO ₂ (µg/m ³)			
		Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹							
			2.5	8	4	2	1	25	5	2
Arches NP	UT	NPS	0.071	0.198	0.033	0.171	0.028	0.019	0.008	0.001
Bandelier NM	NM	NPS	0.021	0.157	0.021	0.095	0.010	0.003	0.001	0.000
Black Canyon of the Gunnison NM	CO	NPS	0.070	0.297	0.051	0.261	0.040	0.015	0.009	0.001
Bosque del Apache Wilderness	NM	FWS	0.002	0.057	0.004	0.035	0.003	0.002	0.001	0.000
Canyonlands NP	UT	NPS	0.028	0.148	0.019	0.119	0.013	0.012	0.006	0.000
Capitol Reef NP	UT	NPS	0.008	0.072	0.007	0.046	0.004	0.005	0.002	0.000
Eagles Nest Wilderness	CO	FS	0.064	0.191	0.062	0.174	0.052	0.015	0.005	0.001
Flat Tops Wilderness	CO	FS	0.142	0.837	0.134	0.835	0.118	0.068	0.027	0.003
Galiuro Wilderness	AZ	FS	0.000	0.013	0.000	0.007	0.000	0.000	0.000	0.000
Gila Wilderness	NM	FS	0.001	0.023	0.001	0.018	0.001	0.002	0.001	0.000
Great Sand Dunes NM	CO	NPS	0.018	0.096	0.027	0.083	0.019	0.005	0.002	0.000
La Garita Wilderness	CO	FS	0.021	0.118	0.023	0.113	0.017	0.009	0.003	0.000
Maroon Bells-Snowmass Wilderness	CO	FS	0.111	0.444	0.127	0.396	0.106	0.018	0.006	0.001
Mesa Verde NP	CO	NPS	2.870	1.815	0.701	0.512	0.148	0.010	0.005	0.002
Mount Baldy Wilderness	AZ	FS	0.000	0.028	0.001	0.018	0.001	0.001	0.000	0.000
Mount Zirkel Wilderness	CO	FS	0.046	0.728	0.179	0.719	0.173	0.029	0.011	0.002
Pecos Wilderness	NM	FS	0.019	0.112	0.018	0.063	0.009	0.003	0.001	0.000
Petrified Forest NP	AZ	NPS	0.002	0.045	0.003	0.035	0.002	0.002	0.001	0.000
Rawah Wilderness	CO	FS	0.038	0.314	0.072	0.306	0.062	0.016	0.005	0.001
Rocky Mountain NP	CO	NPS	0.068	0.679	0.090	0.397	0.062	0.016	0.004	0.001
Salt Creek Wilderness	NM	FWS	0.002	0.042	0.004	0.029	0.002	0.001	0.001	0.000
San Pedro Parks Wilderness	NM	FS	0.029	0.169	0.023	0.066	0.010	0.004	0.002	0.000
Weminuche Wilderness	CO	FS	0.066	0.177	0.047	0.091	0.020	0.010	0.003	0.000
West Elk Wilderness	CO	FS	0.072	0.661	0.157	0.650	0.144	0.015	0.007	0.001
Wheeler Peak Wilderness	NM	FS	0.016	0.097	0.020	0.058	0.011	0.004	0.001	0.000
White Mountain Wilderness	NM	FS	0.002	0.040	0.003	0.023	0.002	0.002	0.001	0.000
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	0.240	0.085	0.018

Table 5-11c. Contributions of new oil and gas and mining on Federal lands and new oil and gas on non-Federal lands within the 14 BLM Planning Areas to PSD pollutant concentrations at Class I and sensitive Class II areas (Source Group T) for the 2021 Medium Development Scenario.

Group		G, T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Area							
Across grid cells		Maximum	Max							
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)	PM _{2.5} (µg/m ³)	SO ₂ (µg/m ³)			
		Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹							
			2.5	8	4	2	1	25	5	2
Arches NP	UT	NPS	0.226	0.388	0.056	0.321	0.046	0.103	0.044	0.004
Bandelier NM	NM	NPS	0.024	0.158	0.020	0.120	0.012	0.013	0.006	0.000
Black Canyon of the Gunnison NM	CO	NPS	0.384	0.636	0.160	0.469	0.074	0.083	0.050	0.004
Bosque del Apache Wilderness	NM	FWS	0.003	0.066	0.005	0.047	0.004	0.012	0.004	0.000
Canyonlands NP	UT	NPS	0.064	0.207	0.026	0.168	0.019	0.072	0.031	0.002
Capitol Reef NP	UT	NPS	0.009	0.075	0.006	0.060	0.004	0.025	0.009	0.000
Eagles Nest Wilderness	CO	FS	0.171	0.331	0.090	0.283	0.072	0.088	0.026	0.004
Flat Tops Wilderness	CO	FS	0.330	0.868	0.177	0.852	0.148	0.405	0.150	0.015
Galiuro Wilderness	AZ	FS	0.000	0.018	0.000	0.008	0.000	0.002	0.001	0.000
Gila Wilderness	NM	FS	0.001	0.034	0.002	0.028	0.002	0.011	0.004	0.000
Great Sand Dunes NM	CO	NPS	0.032	0.189	0.039	0.168	0.029	0.027	0.011	0.001
La Garita Wilderness	CO	FS	0.039	0.205	0.032	0.163	0.024	0.052	0.016	0.002
Maroon Bells-Snowmass Wilderness	CO	FS	0.314	0.627	0.182	0.494	0.135	0.110	0.035	0.006
Mesa Verde NP	CO	NPS	4.103	2.042	0.782	0.600	0.176	0.054	0.021	0.004
Mount Baldy Wilderness	AZ	FS	0.001	0.039	0.002	0.035	0.001	0.006	0.002	0.000
Mount Zirkel Wilderness	CO	FS	0.138	0.777	0.203	0.755	0.191	0.172	0.061	0.009
Pecos Wilderness	NM	FS	0.022	0.112	0.018	0.090	0.011	0.016	0.006	0.001
Petrified Forest NP	AZ	NPS	0.003	0.067	0.004	0.045	0.003	0.009	0.004	0.000
Rawah Wilderness	CO	FS	0.116	0.368	0.103	0.324	0.078	0.091	0.028	0.004
Rocky Mountain NP	CO	NPS	0.180	1.594	0.178	0.879	0.092	0.083	0.020	0.004
Salt Creek Wilderness	NM	FWS	0.003	0.055	0.006	0.044	0.003	0.005	0.003	0.000
San Pedro Parks Wilderness	NM	FS	0.033	0.137	0.021	0.085	0.011	0.022	0.009	0.001
Weminuche Wilderness	CO	FS	0.069	0.141	0.039	0.117	0.021	0.059	0.017	0.001
West Elk Wilderness	CO	FS	0.200	0.712	0.195	0.679	0.166	0.091	0.036	0.004
Wheeler Peak Wilderness	NM	FS	0.022	0.106	0.022	0.087	0.014	0.022	0.007	0.001
White Mountain Wilderness	NM	FS	0.003	0.054	0.004	0.033	0.003	0.009	0.003	0.000
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	1.435	0.468	0.102

Table 5-12a. Contributions of new Federal and non-Federal and existing oil and gas throughout the CARMMS 4 km domain and mining on Federal lands in Colorado to PSD pollutant concentrations at Class I areas (Source Group U) for the 2021 High Development Scenario.

Group	G_U	Combined O&G and Mining in 4 km domain									
Across grid cells	Maximum	Max									
Class I	State	Owner	Pollutant	PM ₁₀ (µg/m ³)		PM ₂₅ (µg/m ³)		SO ₂ (µg/m ³)			
			Averaging Time	Annual ¹	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
			PSD Class I Increment ¹								
			2.5	8	4	2	1	25	5	2	
Arches NP	UT	NPS	0.357	0.577	0.096	0.430	0.080	0.107	0.046	0.006	
Bandelier NM	NM	NPS	0.348	0.611	0.063	0.561	0.048	0.106	0.039	0.005	
Black Canyon of the Gunnison NM	CO	NPS	0.481	0.763	0.199	0.617	0.104	0.086	0.052	0.006	
Bosque del Apache Wilderness	NM	FWS	0.022	0.152	0.013	0.126	0.010	0.047	0.019	0.001	
Canyonlands NP	UT	NPS	0.160	0.356	0.052	0.288	0.041	0.176	0.070	0.006	
Capitol Reef NP	UT	NPS	0.083	0.171	0.019	0.166	0.014	0.162	0.054	0.004	
Eagles Nest Wilderness	CO	FS	0.246	0.566	0.131	0.485	0.099	0.093	0.029	0.005	
Flat Tops Wilderness	CO	FS	0.515	1.093	0.241	0.882	0.189	0.422	0.157	0.017	
Galiuro Wilderness	AZ	FS	0.001	0.038	0.001	0.027	0.001	0.008	0.002	0.000	
Gila Wilderness	NM	FS	0.004	0.072	0.004	0.064	0.004	0.016	0.006	0.000	
Great Sand Dunes NM	CO	NPS	0.117	0.331	0.078	0.297	0.063	0.057	0.016	0.003	
La Garita Wilderness	CO	FS	0.135	0.341	0.059	0.293	0.045	0.074	0.024	0.004	
Maroon Bells-Snowmass Wilderness	CO	FS	0.447	0.824	0.241	0.587	0.167	0.114	0.036	0.007	
Mesa Verde NP	CO	NPS	4.779	2.880	1.108	0.833	0.252	0.497	0.130	0.016	
Mount Baldy Wilderness	AZ	FS	0.003	0.080	0.004	0.066	0.003	0.017	0.006	0.000	
Mount Zirkel Wilderness	CO	FS	0.228	0.893	0.240	0.822	0.219	0.179	0.065	0.010	
Pecos Wilderness	NM	FS	0.195	0.337	0.046	0.272	0.033	0.096	0.040	0.005	
Petrified Forest NP	AZ	NPS	0.028	0.112	0.008	0.089	0.007	0.137	0.018	0.001	
Rawah Wilderness	CO	FS	0.210	0.492	0.148	0.379	0.103	0.095	0.029	0.005	
Rocky Mountain NP	CO	NPS	0.240	1.882	0.207	1.164	0.116	0.087	0.021	0.005	
Salt Creek Wilderness	NM	FWS	0.027	0.120	0.012	0.097	0.009	0.176	0.038	0.002	
San Pedro Parks Wilderness	NM	FS	0.433	0.329	0.058	0.230	0.041	0.175	0.066	0.011	
Weminuche Wilderness	CO	FS	0.446	0.494	0.097	0.459	0.062	0.171	0.046	0.006	
West Elk Wilderness	CO	FS	0.289	0.790	0.238	0.706	0.193	0.095	0.037	0.005	
Wheeler Peak Wilderness	NM	FS	0.145	0.251	0.052	0.207	0.038	0.072	0.021	0.004	
White Mountain Wilderness	NM	FS	0.015	0.116	0.010	0.095	0.008	0.025	0.010	0.001	
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	1.495	0.487	0.108	

Table 5-12b. Contributions of new Federal and non-Federal and existing oil and gas throughout the CARMMS 4 km domain and mining on Federal lands in Colorado to PSD pollutant concentrations at Class I areas (Source Group U) for the 2021 Low Development Scenario.

Group		G_U	Combined O&G and Mining in 4 km domain								
Across grid cells		Maximum	Max								
Class I	State	Owner	Pollutant	PM ₁₀ (µg/m ³)		PM ₂₅ (µg/m ³)		SO ₂ (µg/m ³)			
			Averaging Time	Annual ¹	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
			PSD Class I Increment ¹								
			2.5	8	4	2	1	25	5	2	
Arches NP	UT	NPS	0.192	0.372	0.068	0.311	0.060	0.066	0.032	0.003	
Bandelier NM	NM	NPS	0.342	0.531	0.057	0.495	0.045	0.105	0.038	0.005	
Black Canyon of the Gunnison NM	CO	NPS	0.124	0.431	0.080	0.382	0.068	0.040	0.014	0.003	
Bosque del Apache Wilderness	NM	FWS	0.021	0.129	0.011	0.112	0.009	0.047	0.019	0.001	
Canyonlands NP	UT	NPS	0.138	0.320	0.040	0.249	0.033	0.175	0.070	0.006	
Capitol Reef NP	UT	NPS	0.080	0.168	0.017	0.163	0.013	0.160	0.054	0.003	
Eagles Nest Wilderness	CO	FS	0.128	0.401	0.090	0.360	0.076	0.020	0.014	0.002	
Flat Tops Wilderness	CO	FS	0.269	0.856	0.176	0.852	0.154	0.082	0.033	0.005	
Galiuro Wilderness	AZ	FS	0.000	0.029	0.001	0.023	0.000	0.008	0.002	0.000	
Gila Wilderness	NM	FS	0.003	0.058	0.003	0.052	0.003	0.015	0.005	0.000	
Great Sand Dunes NM	CO	NPS	0.099	0.298	0.059	0.263	0.049	0.057	0.016	0.002	
La Garita Wilderness	CO	FS	0.118	0.283	0.044	0.260	0.036	0.074	0.024	0.003	
Maroon Bells-Snowmass Wilderness	CO	FS	0.193	0.518	0.156	0.449	0.130	0.029	0.012	0.003	
Mesa Verde NP	CO	NPS	3.146	1.925	0.738	0.621	0.181	0.497	0.125	0.015	
Mount Baldy Wilderness	AZ	FS	0.002	0.066	0.003	0.051	0.003	0.017	0.006	0.000	
Mount Zirkel Wilderness	CO	FS	0.119	0.797	0.209	0.781	0.199	0.035	0.015	0.003	
Pecos Wilderness	NM	FS	0.189	0.235	0.040	0.203	0.030	0.096	0.039	0.004	
Petrified Forest NP	AZ	NPS	0.026	0.102	0.007	0.084	0.006	0.136	0.017	0.001	
Rawah Wilderness	CO	FS	0.106	0.391	0.103	0.337	0.083	0.020	0.007	0.002	
Rocky Mountain NP	CO	NPS	0.119	0.998	0.115	0.715	0.082	0.020	0.009	0.002	
Salt Creek Wilderness	NM	FWS	0.025	0.103	0.010	0.085	0.008	0.176	0.038	0.002	
San Pedro Parks Wilderness	NM	FS	0.425	0.299	0.052	0.229	0.038	0.174	0.064	0.010	
Weminuche Wilderness	CO	FS	0.431	0.494	0.088	0.459	0.057	0.171	0.046	0.006	
West Elk Wilderness	CO	FS	0.126	0.680	0.183	0.667	0.167	0.034	0.011	0.003	
Wheeler Peak Wilderness	NM	FS	0.137	0.223	0.044	0.193	0.033	0.072	0.021	0.003	
White Mountain Wilderness	NM	FS	0.014	0.105	0.008	0.090	0.007	0.022	0.008	0.001	
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	0.294	0.103	0.024	

Table 5-12c. Contributions of new Federal and non-Federal and existing oil and gas throughout the CARMMS 4 km domain and mining on Federal lands in Colorado to PSD pollutant concentrations at Class I areas (Source Group U) for the 2021 Medium Development Scenario.

Group		G U	Combined O&G and Mining in 4 km domain							
Across grid cells		Maximum	Max							
			Pollutant	NO ₂ (µg/m ³)	PM ₁₀ (µg/m ³)	PM _{2.5} (µg/m ³)	SO ₂ (µg/m ³)			
		Averaging Time	Annual ³	24-hour ²	Annual ³	24-hour ⁴	Annual ³	3-hour ²	24-hour ²	Annual ³
Class I	State	Owner	PSD Class I Increment ¹							
			2.5	8	4	2	1	25	5	2
Arches NP	UT	NPS	0.349	0.505	0.089	0.414	0.077	0.107	0.046	0.006
Bandelier NM	NM	NPS	0.344	0.579	0.056	0.545	0.046	0.106	0.039	0.005
Black Canyon of the Gunnison NM	CO	NPS	0.440	0.710	0.189	0.571	0.100	0.086	0.052	0.006
Bosque del Apache Wilderness	NM	FWS	0.022	0.140	0.012	0.123	0.010	0.047	0.019	0.001
Canyonlands NP	UT	NPS	0.155	0.314	0.047	0.278	0.039	0.176	0.070	0.006
Capitol Reef NP	UT	NPS	0.082	0.166	0.016	0.163	0.014	0.162	0.054	0.004
Eagles Nest Wilderness	CO	FS	0.222	0.512	0.117	0.463	0.094	0.093	0.028	0.005
Flat Tops Wilderness	CO	FS	0.458	0.959	0.218	0.878	0.182	0.421	0.157	0.017
Galiuro Wilderness	AZ	FS	0.001	0.034	0.001	0.026	0.001	0.008	0.002	0.000
Gila Wilderness	NM	FS	0.003	0.067	0.004	0.061	0.003	0.016	0.006	0.000
Great Sand Dunes NM	CO	NPS	0.113	0.303	0.071	0.279	0.060	0.057	0.016	0.003
La Garita Wilderness	CO	FS	0.130	0.316	0.052	0.282	0.043	0.074	0.024	0.004
Maroon Bells-Snowmass Wilderness	CO	FS	0.392	0.701	0.209	0.560	0.158	0.115	0.036	0.007
Mesa Verde NP	CO	NPS	4.383	2.150	0.819	0.709	0.208	0.497	0.130	0.015
Mount Baldy Wilderness	AZ	FS	0.003	0.072	0.004	0.063	0.003	0.017	0.006	0.000
Mount Zirkel Wilderness	CO	FS	0.212	0.858	0.232	0.821	0.216	0.179	0.065	0.010
Pecos Wilderness	NM	FS	0.192	0.324	0.040	0.266	0.032	0.096	0.040	0.005
Petrified Forest NP	AZ	NPS	0.027	0.097	0.008	0.084	0.006	0.137	0.018	0.001
Rawah Wilderness	CO	FS	0.185	0.447	0.134	0.367	0.099	0.095	0.029	0.005
Rocky Mountain NP	CO	NPS	0.234	1.850	0.201	1.152	0.114	0.087	0.021	0.005
Salt Creek Wilderness	NM	FWS	0.026	0.108	0.011	0.092	0.009	0.176	0.038	0.002
San Pedro Parks Wilderness	NM	FS	0.429	0.266	0.050	0.225	0.039	0.175	0.066	0.010
Weminuche Wilderness	CO	FS	0.434	0.470	0.080	0.449	0.058	0.171	0.046	0.006
West Elk Wilderness	CO	FS	0.255	0.746	0.219	0.695	0.188	0.095	0.037	0.005
Wheeler Peak Wilderness	NM	FS	0.142	0.234	0.046	0.201	0.036	0.072	0.021	0.004
White Mountain Wilderness	NM	FS	0.015	0.105	0.009	0.093	0.007	0.025	0.010	0.001
Dinosaur NM ⁵	CO	NPS	NA	NA	NA	NA	NA	1.495	0.487	0.108

5.2 Visibility Impacts at Class I/II Areas using FLAG (2010)

Attachments B-1, B-2 and B-3 are interactive Excel spreadsheets that contain the visibility impacts at Class I and sensitive Class II areas due to emissions from the 24 Source Groups using the FLAG (2010) procedures as described in Section 4.6. There are four interactive sheets in Attachment B:

“Table1” shows maximum change in (delta) visibility (Δdv), the day of maximum Δdv and number of days that Δdv exceed the 0.5 and 1.0 Δdv thresholds for all Class I/II areas and a user selected Source Group that is controlled in cell B1.

“Table2” shows the temporal distribution (i.e., maximum and minimum and 98th, 80th and 20th percentiles) of Δdv by user selected Source Group (controlled by cell B1) for all Class I and II areas.

“Table3” shows maximum (or 98th, 80th, 20th or minimum controlled by cell B1) impact of Δdv from all Source Groups across all Class I, all Class II and combined all Class I and II areas.

“Table4” shows the maximum number of days that Δdv is greater than the 0.5 and 1.0 Δdv thresholds at any Class I or II area for all 24 Source Groups.

“Table 5” shows the number of days that Δdv is greater than the 0.5 and 1.0 Δdv thresholds and the maximum Δdv at each Class I and sensitive Class II area for a user-selected Source Group controlled by cell B1.

Addition information describing the Attachment B-1 and B-2 spreadsheets are contained in sheets “Readme” and “Ref.”

5.2.1 Maximum Visibility Impacts at any Class I Area for all Source Groups

Table 5-13 displays the Class I and II areas where the maximum number of days Δdv exceeds the 0.5 and 1.0 thresholds occurred for each of the 24 Source Groups and the 2021 High Development Scenario. Tables 5-14 and 5-15 show the same information only for the 2021 Low and Medium Development Scenarios, respectively. These Tables were obtained from “Table4” in Attachments B-1, B-2 and B-3. The maximum Δdv impact at any Class I and II area due to each the 24 Source Groups for the 2021 High, Low and Medium Development Scenarios are shown in Table 5-16.

Of the 14 BLM Colorado and New Mexico Planning Areas (Source Groups A through N) plus the total CRFO (Source Group O) and RGFO (Source Group P) Planning Areas, only three have Federal O&G with Δdv visibility impacts at any Class I area that exceed the 0.5 Δdv threshold for the 2021 High Development Scenario as follows (Table 5-13a):

- WRFO with 6 days of $\Delta dv > 0.5$ and no days with $\Delta dv > 1.0$ (Table 5-13a) and max Δdv of 0.789 at Flats Tops Wilderness Area (Table 5-16a).
- GRFO with 2 days of $\Delta dv > 0.5$ and no days with $\Delta dv > 1.0$ and max Δdv of 0.900 at Arches National Park.
- TRFO with 35 days of $\Delta dv > 0.5$ and 4 days with $\Delta dv > 1.0$ and max Δdv of 1.42 at Mesa Verde National Park.

The individual Source Groups A through P of Federal O&G emissions in BLM Planning have no days with $\Delta dv > 0.5$ at any Class I area for the 2021 Low Development Scenario (Table 5-14a). The maximum Δdv at any Class I area for Federal O&G within an individual BLM Planning Area and the 2021 Low Development Scenario is 0.31 from the Farmington Field Office (Mancos Shale Development) (Table 5-16b).

Results for the 2021 Medium Development Scenario are similar but lower than the High Development Scenario with WRFO, GRFO and TRFO having 4, 2 and 5 days with $\Delta dv > 0.5$ at any Class I area with TRFO having 1 day with $\Delta dv > 1.0$ at any Class I area (Table 5-15a).

When looking at the 2021 High Development Scenario visibility impacts at Class II areas, there are four of the 18 BLM Planning Areas (Source Groups A through P) that have maximum Δdv that exceeds the 0.5 threshold, WRFO, GJFO and TRFO, as seen for Class I areas, but also NMFFO for the Class II areas (Tables 5-13b and 5-16a).

- WRFO with 40 days of $\Delta dv > 0.5$ and 5 days with $\Delta dv > 1.0$ and max Δdv of 1.43 at Dinosaur National Monument.

- GRFO with 23 days of $\Delta dv > 0.5$ and 3 days with $\Delta dv > 1.0$ and max Δdv of 1.46 at Colorado National Monument.
- TRFO with 16 days of $\Delta dv > 0.5$ and 3 days with $\Delta dv > 1.0$ and max Δdv of 2.46 at Hovenweep National Monument.
- NMFFO with 210 days of $\Delta dv > 0.5$ and 50 days with $\Delta dv > 1.0$ and max Δdv of 2.46 at Aztec Ruins National Monument.

For the 2021 Low Development Scenario, there is only one individual BLM Planning Area that has visibility impacts greater than 0.5 dv at any Class II area and that is for the NMFFO that has the exact same impacts as listed in the above bullet for the 2021 High Development Scenario (Table 5-14b). This is because the same high O&G development emissions were used for the Mancos Shale Development area in the 2021 High and Low Development Scenario because the contract from the BLM NMSO for developing emissions for the Mancos Shale Development area came in after the CARMMS 2021 Low Development Scenario source apportionment simulation was performed.

New O&G development on Federal lands result in exceedances of the 0.5 dv visibility threshold at Class II areas for the 2021 Medium Development Scenario for the same four BLM Planning Areas as seen for the 2021 High Development Scenarios only with lower number of days (Tables 5-15b and 5-16c).

- WRFO with 38 days of $\Delta dv > 0.5$ and 5 days with $\Delta dv > 1.0$ and max Δdv of 1.34 at Dinosaur National Monument.
- GRFO with 19 days of $\Delta dv > 0.5$ and 3 days with $\Delta dv > 1.0$ and max Δdv of 1.28 at Colorado National Monument.
- TRFO with 5 days of $\Delta dv > 0.5$ and 1 day with $\Delta dv > 1.0$ and max Δdv of 1.18 at Hovenweep National Monument.
- NMFFO with 77 days of $\Delta dv > 0.5$ and 3 days with $\Delta dv > 1.0$ and max Δdv of 1.60 at Aztec Ruins National Monument.

Not surprisingly, when looking at visibility impacts using the FLAG (2010) approach at Class I/II areas due to O&G emissions across combined BLM Planning Areas there are greater visibility impacts than for any individual BLM Planning Area. The FLMs have developed a Cumulative Visibility approach using the regional haze Worst 20 percent days (W20%) and Best 20 percent days (B20%) regional haze rule metric that is used to assess the visibility impacts for these combined Source Groups that is discussed in Section 5.3. The combined Source Group visibility impacts at Class I/II areas using the FLAG (2010) method in Figures 5-13 through 5-15 are provided for information only.

Table 5-13a. Class I area where each of the 24 Source Groups have the maximum number of days that Δdv exceeds the 0.5 and 1.0 dv thresholds for the High Development Scenario.

Source Group	Group Name	>0.5		>1.0	
		Max # of Day @ Class I	Class I (Max Occurs)	Max # of Day @ Class I	Class I (Max Occurs)
A	Little Snake FO	0	NA	0	NA
B	White River FO	6	CI_Flat_Tops	0	NA
C	Colorado River Valley FO (CRVFO)	0	NA	0	NA
D	Roan Plateau Planning area portion of CRVFO	0	NA	0	NA
E	Grand Junction FO	2	CI_Arches	0	NA
F	Uncompahgre FO	0	NA	0	NA
G	Tres Rios FO	35	CI_Mesa_Verde	4	CI_Mesa_Verde
H	Kremmling FO	0	NA	0	NA
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0	NA	0	NA
J	Pawnee Grasslands portion of RGFO#1	0	NA	0	NA
K	RGFO#2 – West-Central/South	0	NA	0	NA
L	RGFO#3 – South	0	NA	0	NA
M	RGFO#4 – East-Central	0	NA	0	NA
N	New Mexico Farmington District	0	NA	0	NA
O	Total Colorado River Field Office	0	NA	0	NA
P	Total Royal Gorge Field Office	0	NA	0	NA
Q	Mining from 13 Colorado BLM Planning Areas	48	CI_Mount_Zirkel	5	CI_Flat_Tops
R	Combined new Federal O&G and Mining from the 13 Colo	72	CI_Mount_Zirkel	12	CI_Mount_Zirkel
S	Combined new Federal and non-Federal O&G and Mining	281	CI_Mesa_Verde	55	CI_Mesa_Verde
T	Cumulative Emissions Scenario – New Federal and non-Fe	285	CI_Mesa_Verde	62	CI_Mesa_Verde
U	Combined O&G and Mining in 4 km domain	312	CI_Mesa_Verde	105	CI_Mesa_Verde
V	Natural Emissions	192	CI_Bosque	139	CI_Bosque
W	2021 All Emissions	365	CI_Arches	365	CI_Arches
X	2008 All Emissions	365	CI_Arches	365	CI_Arches

Table 5-13b. Sensitive Class II area where each of the 24 Source Groups has the maximum number of days that Δdv exceeds the 0.5 and 1.0 dv thresholds for the High Development Scenario.

Source Group	Group Name	>0.5		>1.0	
		Max # of Day @ Class II	Class II (Max Occurs)	Max # of Day @ Class II	Class II (Max Occurs)
A	Little Snake FO	0	NA	0	NA
B	White River FO	40	CII_Dinosaur_all	5	CII_Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0	NA	0	NA
D	Roan Plateau Planning area portion of CRVFO	0	NA	0	NA
E	Grand Junction FO	23	CII_Colorado	3	CII_Colorado
F	Uncompahgre FO	0	NA	0	NA
G	Tres Rios FO	16	CII_South_San_Juan	3	CII_Hovenweep
H	Kremmling FO	0	NA	0	NA
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0	NA	0	NA
J	Pawnee Grasslands portion of RGFO#1	0	NA	0	NA
K	RGFO#2 – West-Central/South	0	NA	0	NA
L	RGFO#3 – South	0	NA	0	NA
M	RGFO#4 – East-Central	0	NA	0	NA
N	New Mexico Farmington District	210	CII_Aztec_Ruins	50	CII_Aztec_Ruins
O	Total Colorado River Field Office	0	NA	0	NA
P	Total Royal Gorge Field Office	0	NA	0	NA
Q	Mining from 13 Colorado BLM Planning Areas	39	CII_Raggeds	8	CII_Dinosaur_all
R	Combined new Federal O&G and Mining from the 13 Colo	110	CII_Dinosaur_all	27	CII_Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining	288	CII_South_San_Juan	43	CII_Colorado
T	Cumulative Emissions Scenario – New Federal and non-Fe	299	CII_South_San_Juan	133	CII_Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	350	CII_Aztec_Ruins	278	CII_Aztec_Ruins
V	Natural Emissions	246	CII_Sevilleta_NWR	202	CII_Sevilleta_NWR
W	2021 All Emissions	365	CII_Alamosa_NWR	365	CII_Alamosa_NWR
X	2008 All Emissions	365	CII_Alamosa_NWR	365	CII_Alamosa_NWR

Table 5-14a. Class I area where each of the 24 Source Groups have the maximum number of days that Adv exceeds the 0.5 and 1.0 dv thresholds for the Low Development Scenario.

Source Group	Group Name	>0.5		>1.0	
		Max # of Day @ Class I	Class I (Max Occurs)	Max # of Day @ Class I	Class I (Max Occurs)
A	Little Snake FO	0	NA	0	NA
B	White River FO	0	NA	0	NA
C	Colorado River Valley FO (CRVFO)	0	NA	0	NA
D	Roan Plateau Planning area portion of CRVFO	0	NA	0	NA
E	Grand Junction FO	0	NA	0	NA
F	Uncompahgre FO	0	NA	0	NA
G	Tres Rios FO	0	NA	0	NA
H	Kremmling FO	0	NA	0	NA
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0	NA	0	NA
J	Pawnee Grasslands portion of RGFO#1	0	NA	0	NA
K	RGFO#2 – West-Central/South	0	NA	0	NA
L	RGFO#3 – South	0	NA	0	NA
M	RGFO#4 – East-Central	0	NA	0	NA
N	New Mexico Farmington District	0	NA	0	NA
O	Total Colorado River Field Office	0	NA	0	NA
P	Total Royal Gorge Field Office	0	NA	0	NA
Q	Mining from 13 Colorado BLM Planning Areas	48	CI_Mount_Zirkel	5	CI_Flat_Tops
R	Combined new Federal O&G and Mining from the 13 Colo	51	CI_Mount_Zirkel	6	CI_Flat_Tops
S	Combined new Federal and non-Federal O&G and Mining	135	CI_Mesa_Verde	10	CI_Mesa_Verde
T	Cumulative Emissions Scenario – New Federal and non-Fe	143	CI_Mesa_Verde	11	CI_Mesa_Verde
U	Combined O&G and Mining in 4 km domain	201	CI_Mesa_Verde	44	CI_Mesa_Verde
V	Natural Emissions	192	CI_Bosque	139	CI_Bosque
W	2021 All Emissions	365	CI_Arches	365	CI_Arches
X	2008 All Emissions	365	CI_Arches	365	CI_Arches

Table 5-14b. Sensitive Class II area where each of the 24 Source Groups has the maximum number of days that Adv exceeds the 0.5 and 1.0 dv thresholds for the Low Development Scenario.

Source Group	Group Name	>0.5		>1.0	
		Max # of Day @ Class II	Class II (Max Occurs)	Max # of Day @ Class II	Class II (Max Occurs)
A	Little Snake FO	0	NA	0	NA
B	White River FO	0	NA	0	NA
C	Colorado River Valley FO (CRVFO)	0	NA	0	NA
D	Roan Plateau Planning area portion of CRVFO	0	NA	0	NA
E	Grand Junction FO	0	NA	0	NA
F	Uncompahgre FO	0	NA	0	NA
G	Tres Rios FO	0	NA	0	NA
H	Kremmling FO	0	NA	0	NA
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0	NA	0	NA
J	Pawnee Grasslands portion of RGFO#1	0	NA	0	NA
K	RGFO#2 – West-Central/South	0	NA	0	NA
L	RGFO#3 – South	0	NA	0	NA
M	RGFO#4 – East-Central	0	NA	0	NA
N	New Mexico Farmington District	210	CII_Aztec_Ruins	50	CII_Aztec_Ruins
O	Total Colorado River Field Office	0	NA	0	NA
P	Total Royal Gorge Field Office	0	NA	0	NA
Q	Mining from 13 Colorado BLM Planning Areas	39	CII_Raggeds	8	CII_Dinosaur_all
R	Combined new Federal O&G and Mining from the 13 Colo	46	CII_Raggeds	9	CII_Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining	91	CII_South_San_Juan	16	CII_Hovenweep
T	Cumulative Emissions Scenario – New Federal and non-Fe	278	CII_Aztec_Ruins	127	CII_Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	349	CII_Aztec_Ruins	275	CII_Aztec_Ruins
V	Natural Emissions	246	CII_Sevilleta_NWR	202	CII_Sevilleta_NWR
W	2021 All Emissions	365	CII_Alamosa_NWR	365	CII_Alamosa_NWR
X	2008 All Emissions	365	CII_Alamosa_NWR	365	CII_Alamosa_NWR

Table 5-15a. Class I area where each of the 24 Source Groups have the maximum number of days that Adv exceeds the 0.5 and 1.0 dv thresholds for the Medium Development Scenario.

Source Group	Group Name	>0.5		>1.0	
		Max # of Day @ Class I	Class I (Max Occurs)	Max # of Day @ Class I	Class I (Max Occurs)
A	Little Snake FO	0	NA	0	NA
B	White River FO	4	CI_Flat_Tops	0	NA
C	Colorado River Valley FO (CRVFO)	0	NA	0	NA
D	Roan Plateau Planning area portion of CRVFO	0	NA	0	NA
E	Grand Junction FO	2	CI_Arches	0	NA
F	Uncompahgre FO	0	NA	0	NA
G	Tres Rios FO	5	CI_Mesa_Verde	1	CI_Mesa_Verde
H	Kremmling FO	0	NA	0	NA
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0	NA	0	NA
J	Pawnee Grasslands portion of RGFO#1	0	NA	0	NA
K	RGFO#2 – West-Central/South	0	NA	0	NA
L	RGFO#3 – South	0	NA	0	NA
M	RGFO#4 – East-Central	0	NA	0	NA
N	New Mexico Farmington District	0	NA	0	NA
O	Total Colorado River Field Office	0	NA	0	NA
P	Total Royal Gorge Field Office	0	NA	0	NA
Q	Mining from 13 Colorado BLM Planning Areas	48	CI_Mount_Zirkel	5	CI_Flat_Tops
R	Combined new Federal O&G and Mining from the 13 Colo	69	CI_Mount_Zirkel	12	CI_Mount_Zirkel
S	Combined new Federal and non-Federal O&G and Mining	209	CI_Mesa_Verde	28	CI_Rocky_Mountain
T	Cumulative Emissions Scenario – New Federal and non-Fe	213	CI_Mesa_Verde	28	CI_Rocky_Mountain
U	Combined O&G and Mining in 4 km domain	265	CI_Mesa_Verde	64	CI_Mesa_Verde
V	Natural Emissions	192	CI_Bosque	139	CI_Bosque
W	2021 All Emissions	365	CI_Arches	365	CI_Arches
X	2008 All Emissions	365	CI_Arches	365	CI_Arches

Table 5-15b. Sensitive Class II area where each of the 24 Source Groups has the maximum number of days that Adv exceeds the 0.5 and 1.0 dv thresholds for the Medium Development Scenario.

Source Group	Group Name	>0.5		>1.0	
		Max # of Day @ Class II	Class II (Max Occurs)	Max # of Day @ Class II	Class II (Max Occurs)
A	Little Snake FO	0	NA	0	NA
B	White River FO	38	CII_Dinosaur_all	5	CII_Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0	NA	0	NA
D	Roan Plateau Planning area portion of CRVFO	0	NA	0	NA
E	Grand Junction FO	19	CII_Colorado	3	CII_Colorado
F	Uncompahgre FO	0	NA	0	NA
G	Tres Rios FO	5	CII_Hovenweep	1	CII_Hovenweep
H	Kremmling FO	0	NA	0	NA
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0	NA	0	NA
J	Pawnee Grasslands portion of RGFO#1	0	NA	0	NA
K	RGFO#2 – West-Central/South	0	NA	0	NA
L	RGFO#3 – South	0	NA	0	NA
M	RGFO#4 – East-Central	0	NA	0	NA
N	New Mexico Farmington District	77	CII_Aztec_Ruins	3	CII_Aztec_Ruins
O	Total Colorado River Field Office	0	NA	0	NA
P	Total Royal Gorge Field Office	0	NA	0	NA
Q	Mining from 13 Colorado BLM Planning Areas	39	CII_Raggeds	8	CII_Dinosaur_all
R	Combined new Federal O&G and Mining from the 13 Colo	102	CII_Dinosaur_all	26	CII_Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining	163	CII_South_San_Juan	38	CII_Colorado
T	Cumulative Emissions Scenario – New Federal and non-Fe	226	CII_Aztec_Ruins	57	CII_Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	342	CII_Aztec_Ruins	240	CII_Aztec_Ruins
V	Natural Emissions	246	CII_Sevilleta_NWR	202	CII_Sevilleta_NWR
W	2021 All Emissions	365	CII_Alamosa_NWR	365	CII_Alamosa_NWR
X	2008 All Emissions	365	CII_Alamosa_NWR	365	CII_Alamosa_NWR

Table 5-16a. Maximum Δ dv impact at any Class I and sensitive Class II area due to each of the 24 Source Groups for the 2021 High Development Scenario.

Source Group	Group Name	Max dv @ Class I	Class I (Max Occurs)	Max dv @ Class II	Class II (Max Occurs)
A	Little Snake FO	0.21939	CI_Mount_Zirkel	0.22310	CII_Dinosaur_all
B	White River FO	0.78870	CI_Flat_Tops	1.43427	CII_Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.10714	CI_Eagles_Nest	0.15269	CII_Colorado
D	Roan Plateau Planning area portion of CRVFO	0.09446	CI_Maroon_Bells	0.14267	CII_Colorado
E	Grand Junction FO	0.90007	CI_Arches	1.46046	CII_Colorado
F	Uncompahgre FO	0.21822	CI_Maroon_Bells	0.26247	CII_Raggeds
G	Tres Rios FO	1.41540	CI_Mesa_Verde	1.46604	CII_Hovenweep
H	Kremmling FO	0.07991	CI_Eagles_Nest	0.05406	CII_Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.02253	CI_Rocky_Mountain	0.01337	CII_Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	0.12545	CI_Rocky_Mountain	0.05321	CII_Mount_Evans
K	RGFO#2 – West-Central/South	0.02275	CI_Pecos	0.03937	CII_Greenhorn_Mounta
L	RGFO#3 – South	0.01940	CI_Great_Sand_Dunes	0.11458	CII_Greenhorn_Mounta
M	RGFO#4 – East-Central	0.00772	CI_Eagles_Nest	0.04298	CII_Lost_Creek
N	New Mexico Farmington District	0.30608	CI_Weminuche	2.45884	CII_Aztec_Ruins
O	Total Colorado River Field Office	0.19924	CI_Eagles_Nest	0.29345	CII_Colorado
P	Total Royal Gorge Field Office	0.14801	CI_Rocky_Mountain	0.11458	CII_Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	1.27398	CI_Flat_Tops	1.90579	CII_Dinosaur_all
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	1.63971	CI_Flat_Tops	2.63206	CII_Colorado
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	4.19030	CI_Rocky_Mountain	4.59771	CII_Colorado
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	4.19144	CI_Rocky_Mountain	4.60319	CII_Colorado
U	Combined O&G and Mining in 4 km domain	5.53454	CI_Rocky_Mountain	11.71349	CII_Dinosaur_all
V	Natural Emissions	61.82309	CI_Bandelier	57.86500	CII_Dome
W	2021 All Emissions	81.23828	CI_Pecos	57.91427	CII_Dome
X	2008 All Emissions	123.70431	CI_Bandelier	115.81325	CII_Dome

Table 5-16b. Maximum Δ dv impact at any Class I and sensitive Class II area due to each of the 24 Source Groups for the 2021 Low Development Scenario.

Source Group	Group Name	Max dv @ Class I	Class I (Max Occurs)	Max dv @ Class II	Class II (Max Occurs)
A	Little Snake FO	0.03379	CI_Mount_Zirkel	0.03217	CII_Dinosaur_all
B	White River FO	0.17342	CI_Flat_Tops	0.35529	CII_Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.08399	CI_Eagles_Nest	0.10547	CII_Colorado
D	Roan Plateau Planning area portion of CRVFO	0.06573	CI_Maroon_Bells	0.08541	CII_Colorado
E	Grand Junction FO	0.06394	CI_Arches	0.10458	CII_Colorado
F	Uncompahgre FO	0.09830	CI_Maroon_Bells	0.08642	CII_Raggeds
G	Tres Rios FO	0.21039	CI_Mesa_Verde	0.20104	CII_Hovenweep
H	Kremmling FO	0.00866	CI_Eagles_Nest	0.00657	CII_Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.00538	CI_Rocky_Mountain	0.00288	CII_Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	0.02803	CI_Rocky_Mountain	0.01093	CII_Mount_Evans
K	RGFO#2 – West-Central/South	0.00197	CI_Pecos	0.00361	CII_Greenhorn_Mounta
L	RGFO#3 – South	0.01214	CI_Great_Sand_Dunes	0.07568	CII_Greenhorn_Mounta
M	RGFO#4 – East-Central	0.00116	CI_Eagles_Nest	0.00677	CII_Lost_Creek
N	New Mexico Farmington District	0.30611	CI_Weminuche	2.45923	CII_Aztec_Ruins
O	Total Colorado River Field Office	0.14638	CI_Maroon_Bells	0.19010	CII_Colorado
P	Total Royal Gorge Field Office	0.03345	CI_Rocky_Mountain	0.07568	CII_Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	1.27455	CI_Flat_Tops	1.90811	CII_Dinosaur_all
R	Combined new Federal O&G and Mining from the 13 Colo	1.32779	CI_Flat_Tops	1.92664	CII_Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining	2.33257	CI_Mesa_Verde	2.89740	CII_Hovenweep
T	Cumulative Emissions Scenario – New Federal and non-Fe	2.34277	CI_Mesa_Verde	3.43746	CII_Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	3.86495	CI_Rocky_Mountain	11.69008	CII_Dinosaur_all
V	Natural Emissions	61.82309	CI_Bandelier	57.86496	CII_Dome
W	2021 All Emissions	81.23822	CI_Pecos	57.91372	CII_Dome
X	2008 All Emissions	123.70431	CI_Bandelier	115.81325	CII_Dome

Table 5-16c. Maximum Δ dv impact at any Class I and sensitive Class II area due to each of the 24 Source Groups for the 2021 Medium Development Scenario.

Source Group	Group Name	Max dv @ Class I	Class I (Max Occurs)	Max dv @ Class II	Class II (Max Occurs)
A	Little Snake FO	0.18773	CI_Mount_Zirkel	0.18619	CII_Dinosaur_all
B	White River FO	0.78275	CI_Flat_Tops	1.33901	CII_Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.08876	CI_Eagles_Nest	0.12445	CII_Colorado
D	Roan Plateau Planning area portion of CRVFO	0.08081	CI_Maroon_Bells	0.12163	CII_Colorado
E	Grand Junction FO	0.83689	CI_Arches	1.28333	CII_Colorado
F	Uncompahgre FO	0.14666	CI_Maroon_Bells	0.17131	CII_Raggeds
G	Tres Rios FO	1.02858	CI_Mesa_Verde	1.18014	CII_Hovenweep
H	Kremmling FO	0.07964	CI_Eagles_Nest	0.03373	CII_Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.01231	CI_Rocky_Mountain	0.00764	CII_Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	0.07521	CI_Rocky_Mountain	0.03252	CII_Mount_Evans
K	RGFO#2 – West-Central/South	0.01639	CI_Pecos	0.02875	CII_Greenhorn_Mounta
L	RGFO#3 – South	0.01298	CI_Great_Sand_Dunes	0.07842	CII_Greenhorn_Mounta
M	RGFO#4 – East-Central	0.00366	CI_Eagles_Nest	0.01837	CII_Lost_Creek
N	New Mexico Farmington District	0.22871	CI_Weminuche	1.60245	CII_Aztec_Ruins
O	Total Colorado River Field Office	0.16619	CI_Eagles_Nest	0.24274	CII_Colorado
P	Total Royal Gorge Field Office	0.08758	CI_Rocky_Mountain	0.07842	CII_Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	1.27401	CI_Flat_Tops	1.90580	CII_Dinosaur_all
R	Combined new Federal O&G and Mining from the 13 Colo	1.60208	CI_Flat_Tops	2.32929	CII_Colorado
S	Combined new Federal and non-Federal O&G and Mining	4.14160	CI_Rocky_Mountain	4.32611	CII_Colorado
T	Cumulative Emissions Scenario – New Federal and non-Fe	4.14242	CI_Rocky_Mountain	4.33038	CII_Colorado
U	Combined O&G and Mining in 4 km domain	5.49465	CI_Rocky_Mountain	11.71799	CII_Dinosaur_all
V	Natural Emissions	61.82309	CI_Bandelier	57.86499	CII_Dome
W	2021 All Emissions	81.23827	CI_Pecos	57.91420	CII_Dome
X	2008 All Emissions	123.70431	CI_Bandelier	115.81325	CII_Dome

5.2.2 Individual Planning Area Contributions to Visibility Impairment at Class I and II Areas using FLAG (2010)

Below we present the visibility impacts at Class I areas due to Federal O&G in five BLM Planning Areas: WRFO, GJFO, TRFO, NMFFO and USFS-PG and the 2021 High, Low and Medium Development Scenarios. The first four BLM Planning Areas were selected because they were the ones that had Δ dv impacts of greater than 0.5 at any Class I or II area (see Table 5-15), whereas USFS-PG was selected as it is one of our example Planning Areas. Tables 5-17 through 5-21 displays the maximum Δ dv and number of days Δ dv exceeds the 0.5 and 1.0 thresholds for all Class I areas due to emissions from Federal O&G development within the WRFO, GJFO, TRFO, NMFFO and USFS-PG Planning Areas, respectively. These Tables were obtained from sheet “Table1” in Attachments B-1, B-2 and B-3. The visibility results for the 2021 High, Low and Medium Development Scenario and these five BLM Planning Areas are summarized as follows, results for the other Source Groups and for sensitive Class II areas can be found in Attachments B-1, B-2 and B-3:

- Federal O&G from the WRFO Planning Area and the 2021 High Development Scenario results in 6 days at Flat Tops, 1 day at Eagles Nest and 2 days at Maroon Bells-Snowmass Class I areas with Δ dv > 0.5 and no days > 1.0 and maximum Δ dv of 0.789, 0.538 and 0.559 at these three Class I areas, respectively (Table 5-17a). The mitigation in the 2021 Medium Development Scenario reduces these values to 4, 0 and 0 days with Δ dv > 0.5 and 0.782, 0.439 and 0.479 maximum Δ dv at Flat Tops, Eagles Nest and Maroon-Bells Class I areas, respectively (Table 5-17c). For the 2021 Low Development Scenario new Federal O&G from the WRFO Planning Area have no days with Δ dv > 0.5 with maximum

Δdv at Flat Tops, Eagles Nest and Maroon Bells-Snowmass of 0.173, 0.107 and 0.122, respectively (Table 5-16b).

- For the 2021 High and Medium Development Scenarios, the GJFO Planning Area has two Class I areas where new Federal O&G emissions result in Δdv greater than 0.5 with 2 days at Arches and 1 day at Black Canyon of the Gunnison that have maximum Δdv of 0.900/0.837 (High/Medium) and 0.580/0.500 (High/Medium), respective (Table 5-18a,c). There are no days with $\Delta dv > 0.5$ at any Class I area due to new Federal O&G emissions within the GJFO Planning area for the 2021 Low Development Scenario (Table 5-18b).
- For new Federal O&G within the TRFO Planning Area the 2021 High Development Scenario has 35 days with $\Delta dv > 0.5$ and 4 days with $\Delta dv > 1.0$ at just the Mesa Verde Class I area (Table 5-19a). These values are reduced to 5 days with $\Delta dv > 0.5$ and 1 day with $\Delta dv > 1.0$ at the Mesa Verde Class I area due to the mitigation in the 2021 Medium Development Scenario (Table 5-19c). There are no days greater than these thresholds for the 2021 Low Development Scenario (Table 5-19b). The maximum Δdv due to the TRFO at Mesa Verde are 1.412, 0.210 and 1.029 for the 2021 High, Low and Medium Development Scenario, respectively.
- There are no days with $\Delta dv > 0.5$ at any Class I area due to Federal O&G emissions from the NMFFO Mancos Shale Development area for all three 2021 emission scenarios (Table 5-20). However, as shown in Attachments B-1, B-2 and B-3, there are 210, 210 and 77 days with $\Delta dv > 0.5$ and 50, 50 and 3 days with $\Delta dv > 1.0$ at the Aztec Ruins sensitive Class II area for the 2021 High, Low and Medium Development Scenarios. Note that the CARMMS 2021 High and Low Development Scenarios both ran with the same High Development Scenario emissions for the NMFFO Mancos Shale O&G emissions since the Low Scenario emissions were not available at the time of the CARMMS 2021 Low Development Scenario CAMx source apportionment simulation.
- New Federal O&G from the USFS-PG Planning Area has no days with $\Delta dv > 0.5$ at any Class I or sensitive Class II area for all three 2021 emissions scenarios (Table 5-21). The maximum Δdv impact due to new Federal O&G development in the USGS-PG Planning Area is 0.125, 0.028 and 0.075 at Rocky Mountain National Park for the, respectively, 2021 High, Low and Medium Development Scenarios (Table 5-21).

Table 5-17a. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the WRFO Planning Area (2021 High Development Scenario).

White River FO					
Short Name	Class I&II Name	Δdv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.43533	1/14/2008	0	0
CI_Bandelier	Bandelier NM	0.11148	1/17/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.47587	2/17/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.03747	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.26536	1/14/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.07285	2/15/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.53773	1/12/2008	0	1
CI_Flat_Tops	Flat Tops Wilderness	0.78870	1/22/2008	0	6
CI_Galiuro	Galiuro Wilderness	0.00336	5/14/2008	0	0
CI_Gila	Gila Wilderness	0.02166	1/17/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.20730	2/17/2008	0	0
CI_La_Garita	La Garita Wilderness	0.14817	3/6/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.55850	1/12/2008	0	2
CI_Mesa_Verde	Mesa Verde NP	0.17805	3/6/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.04517	1/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.32817	1/12/2008	0	0
CI_Pecos	Pecos Wilderness	0.08404	4/13/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.04465	3/23/2008	0	0
CI_Rawah	Rawah Wilderness	0.22532	12/17/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.20118	3/27/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.03710	5/19/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.07923	3/7/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.12011	5/14/2008	0	0
CI_West_Elk	West Elk Wilderness	0.32166	1/12/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.09681	5/20/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.02573	1/14/2008	0	0

Table 5-17b. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the WRFO Planning Area (2021 Low Development Scenario).

White River FO					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.09570	1/14/2008	0	0
CI_Bandelier	Bandelier NM	0.01819	1/17/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.08959	2/17/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.00606	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.05029	1/14/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.01199	2/15/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.10731	1/12/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.17342	1/22/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00057	5/14/2008	0	0
CI_Gila	Gila Wilderness	0.00357	1/14/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.03269	1/12/2008	0	0
CI_La_Garita	La Garita Wilderness	0.02915	3/6/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.12272	1/12/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.02813	3/6/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00755	1/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.06246	1/12/2008	0	0
CI_Pecos	Pecos Wilderness	0.01509	4/13/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.00758	3/23/2008	0	0
CI_Rawah	Rawah Wilderness	0.03847	3/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.03799	3/27/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00666	5/19/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.01379	3/7/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.02257	3/6/2008	0	0
CI_West_Elk	West Elk Wilderness	0.06922	1/12/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.01743	5/20/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.00433	1/14/2008	0	0

Table 5-17c. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the WRFO Planning Area (2021 Medium Development Scenario).

White River FO					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.38770	1/14/2008	0	0
CI_Bandelier	Bandelier NM	0.09901	1/17/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.46855	2/17/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.03146	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.23310	1/14/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.06555	2/15/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.43903	1/12/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.78275	1/12/2008	0	4
CI_Galiuro	Galiuro Wilderness	0.00308	5/14/2008	0	0
CI_Gila	Gila Wilderness	0.01893	1/17/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.18367	2/17/2008	0	0
CI_La_Garita	La Garita Wilderness	0.12817	3/6/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.47918	11/11/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.15716	3/6/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.03930	1/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.32707	1/12/2008	0	0
CI_Pecos	Pecos Wilderness	0.07481	4/13/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.04403	3/23/2008	0	0
CI_Rawah	Rawah Wilderness	0.18687	12/17/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.19646	3/27/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.03306	5/19/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.06799	3/7/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.10672	5/14/2008	0	0
CI_West_Elk	West Elk Wilderness	0.30428	2/17/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.08643	5/20/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.02139	1/14/2008	0	0

Table 5-18a. Maximum Δ dv and number of days Δ dv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the GJFO Planning Area (2021 High Development Scenario).

Grand Junction FO					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.90007	1/13/2008	0	2
CI_Bandelier	Bandelier NM	0.07374	1/17/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.58026	2/16/2008	0	1
CI_Bosque	Bosque del Apache Wilderness	0.02721	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.34965	1/13/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.13423	1/2/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.29818	1/22/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.34568	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00199	5/18/2008	0	0
CI_Gila	Gila Wilderness	0.01637	1/14/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.18116	1/12/2008	0	0
CI_La_Garita	La Garita Wilderness	0.15510	1/12/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.43962	1/12/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.14631	1/17/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.02719	1/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.28359	5/25/2008	0	0
CI_Pecos	Pecos Wilderness	0.07952	1/13/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.02661	3/9/2008	0	0
CI_Rawah	Rawah Wilderness	0.14821	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.16054	3/24/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.02422	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.05123	3/6/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.09183	3/5/2008	0	0
CI_West_Elk	West Elk Wilderness	0.40600	1/12/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.10652	1/12/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.01722	1/14/2008	0	0

Table 5-18b. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the GJFO Planning Area (2021 Low Development Scenario).

Grand Junction FO					
Short Name	Class I&II Name	Δdv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.06394	1/13/2008	0	0
CI_Bandelier	Bandelier NM	0.00426	1/17/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.03463	2/16/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.00157	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.02204	1/13/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.00678	1/2/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.02113	1/22/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.01884	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00012	5/18/2008	0	0
CI_Gila	Gila Wilderness	0.00099	1/14/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.01113	1/13/2008	0	0
CI_La_Garita	La Garita Wilderness	0.01015	3/22/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.03801	1/12/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.00879	1/17/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00165	1/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.01705	5/25/2008	0	0
CI_Pecos	Pecos Wilderness	0.00503	1/13/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.00157	3/9/2008	0	0
CI_Rawah	Rawah Wilderness	0.00923	4/22/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.01079	3/24/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00146	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.00328	3/6/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.00642	3/5/2008	0	0
CI_West_Elk	West Elk Wilderness	0.03084	1/12/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.00653	1/13/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.00101	1/14/2008	0	0

Table 5-18c. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the GJFO Planning Area (2021 Medium Development Scenario).

Grand Junction FO					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.83689	1/13/2008	0	2
CI_Bandelier	Bandelier NM	0.06171	1/17/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.50011	2/16/2008	0	1
CI_Bosque	Bosque del Apache Wilderness	0.02177	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.32464	1/13/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.11614	1/2/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.24399	1/22/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.27841	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00155	5/18/2008	0	0
CI_Gila	Gila Wilderness	0.01337	1/14/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.15145	1/12/2008	0	0
CI_La_Garita	La Garita Wilderness	0.13364	1/12/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.36723	1/12/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.12182	1/17/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.02259	1/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.23447	5/25/2008	0	0
CI_Pecos	Pecos Wilderness	0.06703	1/13/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.02307	3/9/2008	0	0
CI_Rawah	Rawah Wilderness	0.11926	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.13008	3/24/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.02030	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.04261	3/6/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.07837	3/5/2008	0	0
CI_West_Elk	West Elk Wilderness	0.34239	1/12/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.08939	1/12/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.01405	1/14/2008	0	0

Table 5-19a. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the TRFO Planning Area (2021 High Development Scenario).

Tres Rios FO					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.08112	2/10/2008	0	0
CI_Bandelier	Bandelier NM	0.08282	1/18/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.15138	2/11/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.03171	1/13/2008	0	0
CI_Canyonlands	Canyonlands NP	0.14171	12/21/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.02766	1/3/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.06000	5/24/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.08493	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00177	3/23/2008	0	0
CI_Gila	Gila Wilderness	0.01053	4/13/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.03540	11/19/2008	0	0
CI_La_Garita	La Garita Wilderness	0.05190	3/21/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.08297	5/24/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	1.41540	2/10/2008	4	35
CI_Mount_Baldy	Mount Baldy Wilderness	0.01073	3/23/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.07637	5/25/2008	0	0
CI_Pecos	Pecos Wilderness	0.03618	3/11/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.03174	1/14/2008	0	0
CI_Rawah	Rawah Wilderness	0.05117	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.03678	5/24/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.01197	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.06324	1/12/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.06845	3/21/2008	0	0
CI_West_Elk	West Elk Wilderness	0.07588	12/20/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.02479	2/8/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.01629	1/13/2008	0	0

Table 5-19b. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the TRFO Planning Area (2021 Low Development Scenario).

Tres Rios FO					
Short Name	Class I&II Name	Δdv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.01083	2/10/2008	0	0
CI_Bandelier	Bandelier NM	0.00987	1/18/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.01743	2/11/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.00383	1/13/2008	0	0
CI_Canyonlands	Canyonlands NP	0.01906	12/21/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.00330	1/3/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.00728	5/24/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.01074	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00021	3/23/2008	0	0
CI_Gila	Gila Wilderness	0.00133	4/13/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.00413	11/19/2008	0	0
CI_La_Garita	La Garita Wilderness	0.00642	3/21/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.00984	5/24/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.21039	2/10/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00130	3/23/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.00984	5/25/2008	0	0
CI_Pecos	Pecos Wilderness	0.00427	3/11/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.00384	1/14/2008	0	0
CI_Rawah	Rawah Wilderness	0.00634	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.00465	5/24/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00149	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.00768	1/12/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.00834	3/21/2008	0	0
CI_West_Elk	West Elk Wilderness	0.00900	12/20/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.00302	2/8/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.00201	1/13/2008	0	0

Table 5-19c. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the TRFO Planning Area (2021 Medium Development Scenario).

Tres Rios FO					
Short Name	Class I&II Name	Δdv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.06784	2/10/2008	0	0
CI_Bandelier	Bandelier NM	0.06815	1/18/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.12458	2/11/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.02502	1/13/2008	0	0
CI_Canyonlands	Canyonlands NP	0.11730	12/21/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.02288	1/3/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.04997	5/24/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.07172	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00146	3/23/2008	0	0
CI_Gila	Gila Wilderness	0.00855	4/13/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.02765	3/21/2008	0	0
CI_La_Garita	La Garita Wilderness	0.04270	3/21/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.06869	5/24/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	1.02858	2/10/2008	1	5
CI_Mount_Baldy	Mount Baldy Wilderness	0.00885	3/23/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.06459	5/25/2008	0	0
CI_Pecos	Pecos Wilderness	0.02941	3/11/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.02271	1/14/2008	0	0
CI_Rawah	Rawah Wilderness	0.04288	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.03083	5/24/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00975	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.05047	1/12/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.05626	3/21/2008	0	0
CI_West_Elk	West Elk Wilderness	0.06237	12/20/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.02032	2/8/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.01354	1/13/2008	0	0

Table 5-20a. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the NMFFO Planning Area (2021 High Development Scenario).

New Mexico Farmington District					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.05561	11/25/2008	0	0
CI_Bandelier	Bandelier NM	0.15626	1/18/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.12266	5/25/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.02491	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.08824	12/30/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.08109	1/3/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.07141	5/25/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.07557	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00596	5/17/2008	0	0
CI_Gila	Gila Wilderness	0.01445	5/18/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.12535	12/8/2008	0	0
CI_La_Garita	La Garita Wilderness	0.15074	5/24/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.09903	5/25/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.19519	1/1/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.01094	5/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.04961	5/26/2008	0	0
CI_Pecos	Pecos Wilderness	0.08594	3/11/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.07565	1/14/2008	0	0
CI_Rawah	Rawah Wilderness	0.03416	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.03444	5/25/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.02992	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.13503	3/18/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.30608	5/24/2008	0	0
CI_West_Elk	West Elk Wilderness	0.11344	5/25/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.07107	3/24/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.02660	1/13/2008	0	0

Table 5-20b. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the NMFFO Planning Area (2021 Low Development Scenario).

New Mexico Farmington District					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.05560	11/25/2008	0	0
CI_Bandelier	Bandelier NM	0.15753	1/18/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.12277	5/25/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.02532	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.08843	12/30/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.08074	1/3/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.07157	5/25/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.07693	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00600	5/17/2008	0	0
CI_Gila	Gila Wilderness	0.01454	5/18/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.12514	12/8/2008	0	0
CI_La_Garita	La Garita Wilderness	0.15069	5/24/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.09914	5/25/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.19566	1/1/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.01103	5/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.05047	5/26/2008	0	0
CI_Pecos	Pecos Wilderness	0.08613	3/11/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.07619	1/14/2008	0	0
CI_Rawah	Rawah Wilderness	0.03453	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.03407	5/25/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.03084	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.13617	3/18/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.30611	5/24/2008	0	0
CI_West_Elk	West Elk Wilderness	0.11343	5/25/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.07176	3/24/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.02696	1/13/2008	0	0

Table 5-20c. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the NMFFO Planning Area (2021 Medium Development Scenario).

New Mexico Farmington District					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.03949	11/25/2008	0	0
CI_Bandelier	Bandelier NM	0.11621	1/18/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.09211	5/25/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.01757	3/7/2008	0	0
CI_Canyonlands	Canyonlands NP	0.06564	12/30/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.06059	1/3/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.05397	5/25/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.05739	5/25/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00370	5/17/2008	0	0
CI_Gila	Gila Wilderness	0.00984	5/18/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.09241	12/8/2008	0	0
CI_La_Garita	La Garita Wilderness	0.11350	5/24/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.07456	5/25/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.14509	12/30/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00702	5/17/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.03725	5/26/2008	0	0
CI_Pecos	Pecos Wilderness	0.06296	3/11/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.04816	1/14/2008	0	0
CI_Rawah	Rawah Wilderness	0.02590	5/25/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.02598	5/25/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.02222	1/13/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.08660	3/18/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.22871	5/24/2008	0	0
CI_West_Elk	West Elk Wilderness	0.08529	5/25/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.04916	2/8/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.01987	1/13/2008	0	0

Table 5-21a. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the USFS-PG Planning Area (2021 High Development Scenario).

Pawnee Grasslands portion of RGFO#1					
Short Name	Class I&II Name	Adv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.00006	9/30/2008	0	0
CI_Bandelier	Bandelier NM	0.00242	12/9/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.00137	3/17/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.00144	11/15/2008	0	0
CI_Canyonlands	Canyonlands NP	0.00007	7/10/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.00004	7/10/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.00630	3/9/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.00154	3/17/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00008	5/17/2008	0	0
CI_Gila	Gila Wilderness	0.00096	5/17/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.00676	11/27/2008	0	0
CI_La_Garita	La Garita Wilderness	0.00159	4/17/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.00261	3/17/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.00030	3/17/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00039	5/16/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.00255	5/26/2008	0	0
CI_Pecos	Pecos Wilderness	0.00395	11/24/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.00056	5/16/2008	0	0
CI_Rawah	Rawah Wilderness	0.02765	5/26/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.12545	11/20/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00225	5/18/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.00120	5/16/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.00183	4/17/2008	0	0
CI_West_Elk	West Elk Wilderness	0.00204	3/17/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.00246	5/15/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.00268	5/18/2008	0	0

Table 5-21b. Maximum Δdv and number of days Δdv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the USFS-PG Planning Area (2021 Low Development Scenario).

Pawnee Grasslands portion of RGFO#1					
Short Name	Class I&II Name	Δdv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.00001	12/30/2008	0	0
CI_Bandelier	Bandelier NM	0.00048	12/9/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.00032	3/17/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.00028	11/15/2008	0	0
CI_Canyonlands	Canyonlands NP	0.00008	12/30/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.00001	7/10/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.00130	3/9/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.00031	3/17/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00002	5/17/2008	0	0
CI_Gila	Gila Wilderness	0.00019	5/17/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.00139	11/27/2008	0	0
CI_La_Garita	La Garita Wilderness	0.00035	3/17/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.00055	3/17/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.00007	3/17/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00008	5/16/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.00054	5/26/2008	0	0
CI_Pecos	Pecos Wilderness	0.00074	11/24/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.00011	5/16/2008	0	0
CI_Rawah	Rawah Wilderness	0.00556	5/26/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.02803	11/20/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00047	5/18/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.00023	5/16/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.00038	4/17/2008	0	0
CI_West_Elk	West Elk Wilderness	0.00046	3/17/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.00049	5/15/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.00056	5/18/2008	0	0

Table 5-21c. Maximum Δ dv and number of days Δ dv exceeds 0.5 and 1.0 for each Class I area due to emissions from Federal O&G within the USFS-PG Planning Area (2021 Medium Development Scenario).

Pawnee Grasslands portion of RGFO#1					
Short Name	Class I&II Name	Δdv	Date	Number of Day	
				> 1.0	> 0.5
Class I					
CI_Arches	Arches NP	0.00002	9/30/2008	0	0
CI_Bandelier	Bandelier NM	0.00146	12/9/2008	0	0
CI_Black_Canyon	Black Canyon of the Gunnison NM	0.00086	3/17/2008	0	0
CI_Bosque	Bosque del Apache Wilderness	0.00079	11/15/2008	0	0
CI_Canyonlands	Canyonlands NP	0.00003	7/10/2008	0	0
CI_Capitol_Reef	Capitol Reef NP	0.00002	7/10/2008	0	0
CI_Eagles_Nest	Eagles Nest Wilderness	0.00369	3/9/2008	0	0
CI_Flat_Tops	Flat Tops Wilderness	0.00091	3/17/2008	0	0
CI_Galiuro	Galiuro Wilderness	0.00003	5/17/2008	0	0
CI_Gila	Gila Wilderness	0.00047	5/17/2008	0	0
CI_Great_Sand_Dunes	Great Sand Dunes NM	0.00371	11/27/2008	0	0
CI_La_Garita	La Garita Wilderness	0.00099	3/17/2008	0	0
CI_Maroon_Bells	Maroon Bells-Snowmass Wilderness	0.00158	3/17/2008	0	0
CI_Mesa_Verde	Mesa Verde NP	0.00018	3/17/2008	0	0
CI_Mount_Baldy	Mount Baldy Wilderness	0.00019	5/16/2008	0	0
CI_Mount_Zirkel	Mount Zirkel Wilderness	0.00155	5/26/2008	0	0
CI_Pecos	Pecos Wilderness	0.00234	11/24/2008	0	0
CI_Petrified_Forest	Petrified Forest NP	0.00024	5/16/2008	0	0
CI_Rawah	Rawah Wilderness	0.01687	5/26/2008	0	0
CI_Rocky_Mountain	Rocky Mountain NP	0.07521	11/20/2008	0	0
CI_Salt_Creek	Salt Creek Wilderness	0.00124	2/18/2008	0	0
CI_San_Pedro	San Pedro Parks Wilderness	0.00066	11/24/2008	0	0
CI_Weminuche	Weminuche Wilderness	0.00106	4/17/2008	0	0
CI_West_Elk	West Elk Wilderness	0.00126	3/17/2008	0	0
CI_Wheeler_Peak	Wheeler Peak Wilderness	0.00135	5/15/2008	0	0
CI_White_Mountain	White Mountain Wilderness	0.00146	5/18/2008	0	0

5.3 Cumulative Visibility Impacts at Class I Areas

The visibility impacts due to new oil and gas emissions from combined BLM Planning Areas were examined following the procedures provided by the FWS and NPS (FWS and NPS, 2012) and described in Section 4.6.2. These procedures use EPA's Modeled Attainment Test Software (MATS) to project current year observed visibility impairment for the observed best 20 percent (B20%) and worst 20 percent (W20%) visibility days to the future year using the CAMx 2008 Base Case and 2021 High, Low and Medium Development Scenarios modeling results with and without emissions from each of the combined emission Source Groups. The cumulative visibility analysis was conducted for the following four combined Source Groups:

- Source Group R: New oil and gas and mining on Federal lands within the 13 Colorado BLM Planning Areas;
- Source Group S: New oil and gas on Federal and non-Federal lands and mining on Federal lands within the 13 Colorado BLM Planning Areas;

- Source Group T: Cumulative Emissions Scenario of new oil and gas on Federal and non-Federal lands and mining on Federal lands within the 14 Colorado and northern New Mexico BLM Planning Areas;
- Source Group U: Existing and New Federal and non-Federal oil and gas throughout the 4 km CARMMS domain plus mining on Federal land within the 13 Colorado BLM Planning Areas.

Attachments C-1, C-2 and C-3 contain the 2008 observed and 2021 projected visibility for the W20% and B20% days at Class I and sensitive Class II areas for the, respectively, High, Low and Medium Development Scenarios with and without each of the combined Source Groups. Tables 5-22 through 5-27 from Attachments C-1, C-2 and C-3 displays the cumulative visibility results at Class I areas for the 2021 High, Low and Medium Development Scenarios, the four combined emission Source Groups listed above and the W20% and B20% days. MATS uses observed PM species concentrations and monthly average relative humidity from IMPROVE monitoring sites to calculate daily visibility impairment from which the W20% and B20% visibility days metrics are determined. Not all Class I areas have a co-located IMPROVE monitoring site. Thus, IMPROVE observations were mapped to nearby Class I areas that did not include an IMPROVE monitor. In Tables 5-22 through 5-27, the Class I area of interest is shown in the first column and the IMPROVE site used to represent observed visibility at the Class I area is shown in the third column. For example, the IMPROVE data from Canyonlands National Park was used to represent observed visibility for both the Canyonlands and Arches National Parks. The MATS includes the IMPROVE site to Class I area mappings. However, MATS does not include mappings between IMPROVE sites and sensitive Class II areas. Thus, we assigned an IMPROVE monitoring site to each sensitive Class II area based mainly on proximity so that MATS could calculate cumulative visibility impacts for the W20%/B20% days at sensitive Class II areas. Tables 5-22 through 5-26 include cumulative visibility impacts for just the Class I areas, the results for the sensitive Class II areas are included in Attachments C-1, C-2 and C-3.

Table 5-22a displays the observed W20% visibility metric for the current year (2008) and the projected W20% metric for the 2021 High Development Scenario with and without each of the four combined Source Groups with differences in the W20% visibility metric shown in Table 5-22b. From the 2008 current year to the 2021 High Development Scenario future year, the W20% visibility metric is estimated to improve at 24 and degrade at 2 of the 26 Class I areas. The biggest improvement in W20% visibility between 2008 and 2021 High Scenario is a reduction of 0.89 dv that occurs at Rocky Mountain National Park that goes from 12.04 dv in 2008 to 11.15 dv in the 2021 High Development Scenario. The two Class I areas with degradation are Salt Creek (0.22 dv increase) and White Mountain (0.23 dv increase).

There are even more improvements in the W20% visibility between 2008 and 2021 for the Low Development Scenario (Table 5-23). Again the Class I area with the biggest improvement between 2008 and 2021 Low Scenario is a reduction of 0.92 dv at Rocky Mountain National Park. Again 24 of the 26 Class I areas see W20% visibility improvements between 2008 and 2021 Low Scenario with the same two Class I areas showing W20% visibility degradation in the High and Low Development Scenarios. The results for the 2021 Medium Development Scenario are similar with 24 of 26 Class I areas showing improvements in the W20% visibility metric with

the largest improvement (0.89 dv decrease) occurring at Rocky Mountain National Park (Table 5-24).

The Source Group R (new Federal O&G and mining in Colorado) contribution to 2021 W20% visibility ranges from a minimum of zero to maximums of 0.12 (High), 0.10 (Low) and 0.12 (Medium) dv (Tables 5-22b, 5-23b and 5-24b). Whereas, the contributions of all O&G emissions in the 4 km CARMMS domain (Source Group U) to the W20% days is always positive with maximum values of 0.50, 0.40 and 0.45 dv for the High, Low and Medium Development Scenarios, respectively.

The results for the B20% visibility days and High, Low and Medium Development Scenarios are shown in Tables 5-25 through 5-27. Between 2008 and 2021 the B20% visibility improves for approximately half and degrades for the other half of the Class I areas for all three 2021 emission scenarios. The largest improvement in B20% visibility for the High, Low and Medium Development Scenarios are 0.16, 0.20 and 0.17 dv and the largest degradation in B20% visibility is 0.61, 0.57 and 0.61 dv, respectively. The Source Groups' R, S, T and U contributions to the B20% visibility range from zero to 0.16, 0.33, 0.40 and 0.80 dv for the High and zero to 0.13, 0.16, 0.23 and 0.75 dv for the Low Development Scenarios with the 2021 Medium Development scenario results falling between the High and Low Development Scenarios.

Table 5-22a. Cumulative visibility results for W20% visibility days at Class I areas for current year (2008) and 2021 High Development Scenario using all emissions and without Source Groups R, S, T and U.

Class I Name	State	IMPROVE Site	2008 Base	2021 High	2021 High w/o R	2021 High w/o S	2021 High w/o T	2021 High w/o U
Arches NP	UT	CANY1	11.02	10.37	10.34	10.26	10.26	10.19
Mount Baldy Wilderness	AZ	BALD1	11.10	10.56	10.56	10.55	10.55	10.54
Bandelier NM	NM	BAND1	11.33	10.88	10.83	10.80	10.79	10.44
Black Canyon of the Gunnison NM	CO	WEMI1	9.95	9.31	9.30	9.11	9.11	9.05
Bosque del Apache	NM	BOAP1	12.72	12.31	12.30	12.30	12.30	12.27
Canyonlands NP	UT	CANY1	12.49	11.98	11.96	11.91	11.91	11.86
Capitol Reef NP	UT	CAPI1	12.92	12.72	12.71	12.65	12.65	12.61
Eagles Nest Wilderness	CO	WHRI1	8.68	7.87	7.85	7.78	7.78	7.70
Flat Tops Wilderness	CO	WHRI1	8.68	8.07	8.06	7.89	7.89	7.85
Galiuro Wilderness ¹	AZ	CHIR1	11.58	11.19	11.19	11.19	11.19	11.18
Gila Wilderness	NM	GICL1	11.58	11.54	11.54	11.54	11.54	11.54
Great Sand Dunes NM	CO	GRSA1	10.90	10.78	10.73	10.70	10.70	10.66
La Garita Wilderness	CO	WEMI1	9.95	9.36	9.35	9.34	9.33	9.31
Maroon Bells-Snowmass Wilderness	CO	WHRI1	8.68	7.91	7.89	7.84	7.84	7.80
Mesa Verde NP	CO	MEVE1	11.20	10.82	10.79	10.77	10.76	10.71
Mount Zirkel Wilderness	CO	MOZI1	9.36	8.54	8.53	8.45	8.45	8.42
Pecos Wilderness ²	NM	BAND1	11.33	10.86	10.80	10.76	10.75	10.51
Petrified Forest NP	AZ	PEFO1	12.49	12.06	12.04	12.02	12.02	11.89
Rawah Wilderness	CO	MOZI1	9.36	8.53	8.52	8.44	8.44	8.39
Rocky Mountain NP	CO	ROMO1	12.04	11.15	11.14	11.09	11.09	11.03
Salt Creek	NM	SACR1	16.87	17.09	17.08	17.08	17.08	17.06
San Pedro Parks Wilderness	NM	SAPE1	9.43	8.72	8.60	8.58	8.58	8.54
West Elk Wilderness	CO	WHRI1	8.68	8.08	8.06	8.01	8.01	7.97
Weminuche Wilderness	CO	WEMI1	9.95	9.49	9.46	9.45	9.45	9.42
Wheeler Peak Wilderness ²	NM	BAND1	11.33	10.86	10.75	10.59	10.52	10.36
White Mountain Wilderness	NM	WHIT1	12.92	13.15	13.15	13.15	13.15	13.13

Table 5-22b. Differences in cumulative visibility results for W20% visibility days at Class I areas between current year (2008) and 2021 High Development Scenario (2008-2021) and contributions of Source Groups R, S, T and U to 2021 W20% day's visibility.

Class I Name	State	IMPROVE Site	2021 High Improvement from 2008	Contribution from R	Contribution from S	Contribution from T	Contribution from U
Arches NP	UT	CANY1	0.65	0.03	0.11	0.11	0.18
Mount Baldy Wilderness	AZ	BALD1	0.54	0.00	0.01	0.01	0.02
Bandelier NM	NM	BAND1	0.45	0.05	0.08	0.09	0.44
Black Canyon of the Gunnison NM	CO	WEMI1	0.64	0.01	0.20	0.20	0.26
Bosque del Apache	NM	BOAP1	0.41	0.01	0.01	0.01	0.04
Canyonlands NP	UT	CANY1	0.51	0.02	0.07	0.07	0.12
Capitol Reef NP	UT	CAPI1	0.20	0.01	0.07	0.07	0.11
Eagles Nest Wilderness	CO	WHRI1	0.81	0.02	0.09	0.09	0.17
Flat Tops Wilderness	CO	WHRI1	0.61	0.01	0.18	0.18	0.22
Galiuro Wilderness ¹	AZ	CHIR1	0.39	0.00	0.00	0.00	0.01
Gila Wilderness	NM	GICL1	0.04	0.00	0.00	0.00	0.00
Great Sand Dunes NM	CO	GRSA1	0.12	0.05	0.08	0.08	0.12
La Garita Wilderness	CO	WEMI1	0.59	0.01	0.02	0.03	0.05
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.77	0.02	0.07	0.07	0.11
Mesa Verde NP	CO	MEVE1	0.38	0.03	0.05	0.06	0.11
Mount Zirkel Wilderness	CO	MOZI1	0.82	0.01	0.09	0.09	0.12
Pecos Wilderness ²	NM	BAND1	0.47	0.06	0.10	0.11	0.35
Petrified Forest NP	AZ	PEFO1	0.43	0.02	0.04	0.04	0.17
Rawah Wilderness	CO	MOZI1	0.83	0.01	0.09	0.09	0.14
Rocky Mountain NP	CO	ROMO1	0.89	0.01	0.06	0.06	0.12
Salt Creek	NM	SACR1	-0.22	0.01	0.01	0.01	0.03
San Pedro Parks Wilderness	NM	SAPE1	0.71	0.12	0.14	0.14	0.18
West Elk Wilderness	CO	WHRI1	0.60	0.02	0.07	0.07	0.11
Weminuche Wilderness	CO	WEMI1	0.46	0.03	0.04	0.04	0.07
Wheeler Peak Wilderness ²	NM	BAND1	0.47	0.11	0.27	0.34	0.50
White Mountain Wilderness	NM	WHIT1	-0.23	0.00	0.00	0.00	0.02

Table 5-23a. Cumulative visibility results for W20% visibility days at Class I areas for current year (2008) and 2021 Low Development Scenario using all emissions and without Source Groups R, S, T and U.

Class I Name	State	IMPROVE Site	2008 Base	2021 Low	2021 Low w/o R	2021 Low w/o S	2021 Low w/o T	2021 Low w/o U
Arches NP	UT	CANY1	11.02	10.33	10.32	10.28	10.28	10.21
Mount Baldy Wilderness	AZ	BALD1	11.10	10.56	10.56	10.55	10.55	10.54
Bandelier NM	NM	BAND1	11.33	10.85	10.83	10.81	10.81	10.45
Black Canyon of the Gunnison NM	CO	WEMI1	9.95	9.21	9.20	9.12	9.12	9.06
Bosque del Apache	NM	BOAP1	12.72	12.31	12.31	12.30	12.30	12.27
Canyonlands NP	UT	CANY1	12.49	11.95	11.94	11.92	11.91	11.87
Capitol Reef NP	UT	CAPI1	12.92	12.69	12.69	12.66	12.66	12.62
Eagles Nest Wilderness	CO	WHRI1	8.68	7.83	7.82	7.79	7.79	7.71
Flat Tops Wilderness	CO	WHRI1	8.68	8.00	7.99	7.91	7.91	7.86
Galiuro Wilderness ¹	AZ	CHIR1	11.58	11.19	11.19	11.19	11.19	11.18
Gila Wilderness	NM	GICL1	11.58	11.54	11.54	11.54	11.54	11.54
Great Sand Dunes NM	CO	GRSA1	10.90	10.76	10.73	10.72	10.71	10.67
La Garita Wilderness	CO	WEMI1	9.95	9.35	9.35	9.34	9.34	9.31
Maroon Bells-Snowmass Wilderness	CO	WHRI1	8.68	7.88	7.87	7.85	7.85	7.81
Mesa Verde NP	CO	MEVE1	11.20	10.81	10.79	10.78	10.78	10.72
Mount Zirkel Wilderness	CO	MOZI1	9.36	8.49	8.49	8.45	8.45	8.42
Pecos Wilderness ²	NM	BAND1	11.33	10.82	10.80	10.78	10.77	10.52
Petrified Forest NP	AZ	PEFO1	12.49	12.04	12.04	12.02	12.02	11.89
Rawah Wilderness	CO	MOZI1	9.36	8.48	8.47	8.44	8.44	8.39
Rocky Mountain NP	CO	ROMO1	12.04	11.12	11.12	11.09	11.09	11.03
Salt Creek	NM	SACR1	16.87	17.09	17.08	17.08	17.08	17.06
San Pedro Parks Wilderness	NM	SAP11	9.43	8.70	8.60	8.59	8.59	8.55
West Elk Wilderness	CO	WHRI1	8.68	8.05	8.04	8.02	8.01	7.98
Weminuche Wilderness	CO	WEMI1	9.95	9.48	9.46	9.46	9.45	9.43
Wheeler Peak Wilderness ²	NM	BAND1	11.33	10.75	10.70	10.61	10.55	10.38
White Mountain Wilderness	NM	WHIT1	12.92	13.15	13.15	13.15	13.15	13.13

Table 5-23b. Differences in cumulative visibility results for W20% visibility days at Class I areas between current year (2008) and 2021 Low Development Scenario (2008-2021) and contributions of Source Groups R, S, T and U to 2021 W20% day's visibility.

Class I Name	State	IMPROVE Site	2021 Low Improvement from 2008	Contribution from R	Contribution from S	Contribution from T	Contribution from U
Arches NP	UT	CANY1	0.69	0.01	0.05	0.05	0.12
Mount Baldy Wilderness	AZ	BALD1	0.54	0.00	0.01	0.01	0.02
Bandelier NM	NM	BAND1	0.48	0.02	0.04	0.04	0.40
Black Canyon of the Gunnison NM	CO	WEMI1	0.74	0.01	0.09	0.09	0.15
Bosque del Apache	NM	BOAP1	0.41	0.00	0.01	0.01	0.04
Canyonlands NP	UT	CANY1	0.54	0.01	0.03	0.04	0.08
Capitol Reef NP	UT	CAPI1	0.23	0.00	0.03	0.03	0.07
Eagles Nest Wilderness	CO	WHRI1	0.85	0.01	0.04	0.04	0.12
Flat Tops Wilderness	CO	WHRI1	0.68	0.01	0.09	0.09	0.14
Galiuro Wilderness ¹	AZ	CHIR1	0.39	0.00	0.00	0.00	0.01
Gila Wilderness	NM	GICL1	0.04	0.00	0.00	0.00	0.00
Great Sand Dunes NM	CO	GRSA1	0.14	0.03	0.04	0.05	0.09
La Garita Wilderness	CO	WEMI1	0.60	0.00	0.01	0.01	0.04
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.80	0.01	0.03	0.03	0.07
Mesa Verde NP	CO	MEVE1	0.39	0.02	0.03	0.03	0.09
Mount Zirkel Wilderness	CO	MOZI1	0.87	0.00	0.04	0.04	0.07
Pecos Wilderness ²	NM	BAND1	0.51	0.02	0.04	0.05	0.30
Petrified Forest NP	AZ	PEFO1	0.45	0.00	0.02	0.02	0.15
Rawah Wilderness	CO	MOZI1	0.88	0.01	0.04	0.04	0.09
Rocky Mountain NP	CO	ROMO1	0.92	0.00	0.03	0.03	0.09
Salt Creek	NM	SACR1	-0.22	0.01	0.01	0.01	0.03
San Pedro Parks Wilderness	NM	SAP11	0.73	0.10	0.11	0.11	0.15
West Elk Wilderness	CO	WHRI1	0.63	0.01	0.03	0.04	0.07
Weminuche Wilderness	CO	WEMI1	0.47	0.02	0.02	0.03	0.05
Wheeler Peak Wilderness ²	NM	BAND1	0.58	0.05	0.14	0.20	0.37
White Mountain Wilderness	NM	WHIT1	-0.23	0.00	0.00	0.00	0.02

Table 5-24a. Cumulative visibility results for W20% visibility days at Class I areas for current year (2008) and 2021 Medium Development Scenario using all emissions and without Source Groups R, S, T and U.

Class I Name	State	IMPROVE Site	2008 Base	2021 Medium	2021 Med w/o R	2021 Med w/o S	2021 Med w/o T	2021 Med w/o U
Arches NP	UT	CANY1	11.02	10.36	10.35	10.26	10.26	10.19
Mount Baldy Wilderness	AZ	BALD1	11.10	10.56	10.56	10.55	10.55	10.54
Bandelier NM	NM	BAND1	11.33	10.87	10.83	10.80	10.79	10.44
Black Canyon of the Gunnison NM	CO	WEMI1	9.95	9.31	9.30	9.11	9.11	9.05
Bosque del Apache	NM	BOAP1	12.72	12.31	12.30	12.30	12.30	12.27
Canyonlands NP	UT	CANY1	12.49	11.98	11.96	11.91	11.91	11.86
Capitol Reef NP	UT	CAPI1	12.92	12.72	12.71	12.65	12.65	12.61
Eagles Nest Wilderness	CO	WHRI1	8.68	7.86	7.85	7.78	7.78	7.70
Flat Tops Wilderness	CO	WHRI1	8.68	8.07	8.06	7.89	7.89	7.85
Galiuro Wilderness ¹	AZ	CHIR1	11.58	11.19	11.19	11.19	11.19	11.18
Gila Wilderness	NM	GICL1	11.58	11.54	11.54	11.54	11.54	11.54
Great Sand Dunes NM	CO	GRSA1	10.90	10.77	10.73	10.71	10.70	10.66
La Garita Wilderness	CO	WEMI1	9.95	9.36	9.35	9.33	9.33	9.31
Maroon Bells-Snowmass Wilderness	CO	WHRI1	8.68	7.90	7.89	7.85	7.84	7.80
Mesa Verde NP	CO	MEVE1	11.20	10.82	10.79	10.77	10.77	10.71
Mount Zirkel Wilderness	CO	MOZI1	9.36	8.54	8.53	8.45	8.45	8.42
Pecos Wilderness ²	NM	BAND1	11.33	10.84	10.80	10.76	10.75	10.51
Petrified Forest NP	AZ	PEFO1	12.49	12.06	12.04	12.02	12.02	11.89
Rawah Wilderness	CO	MOZI1	9.36	8.53	8.52	8.44	8.44	8.39
Rocky Mountain NP	CO	ROMO1	12.04	11.15	11.14	11.09	11.09	11.03
Salt Creek	NM	SACR1	16.87	17.09	17.08	17.08	17.08	17.06
San Pedro Parks Wilderness	NM	SAPE1	9.43	8.72	8.60	8.58	8.58	8.54
West Elk Wilderness	CO	WHRI1	8.68	8.08	8.06	8.01	8.01	7.97
Weminuche Wilderness	CO	WEMI1	9.95	9.48	9.46	9.45	9.45	9.42
Wheeler Peak Wilderness ²	NM	BAND1	11.33	10.81	10.72	10.56	10.53	10.36
White Mountain Wilderness	NM	WHIT1	12.92	13.15	13.15	13.15	13.15	13.13

Table 5-24b. Differences in cumulative visibility results for W20% visibility days at Class I areas between current year (2008) and 2021 Medium Development Scenario (2008-2021) and contributions of Source Groups R, S, T and U to 2021 W20% day's visibility.

Class I Name	State	IMPROVE Site	2021 Med Improvement from 2008	Contribution from R	Contribution from S	Contribution from T	Contribution from U
Arches NP	UT	CANY1	0.66	0.01	0.10	0.10	0.17
Mount Baldy Wilderness	AZ	BALD1	0.54	0.00	0.01	0.01	0.02
Bandelier NM	NM	BAND1	0.46	0.04	0.07	0.08	0.43
Black Canyon of the Gunnison NM	CO	WEMI1	0.64	0.01	0.20	0.20	0.26
Bosque del Apache	NM	BOAP1	0.41	0.01	0.01	0.01	0.04
Canyonlands NP	UT	CANY1	0.51	0.02	0.07	0.07	0.12
Capitol Reef NP	UT	CAPI1	0.20	0.01	0.07	0.07	0.11
Eagles Nest Wilderness	CO	WHRI1	0.82	0.01	0.08	0.08	0.16
Flat Tops Wilderness	CO	WHRI1	0.61	0.01	0.18	0.18	0.22
Galiuro Wilderness ¹	AZ	CHIR1	0.39	0.00	0.00	0.00	0.01
Gila Wilderness	NM	GICL1	0.04	0.00	0.00	0.00	0.00
Great Sand Dunes NM	CO	GRSA1	0.13	0.04	0.06	0.07	0.11
La Garita Wilderness	CO	WEMI1	0.59	0.01	0.03	0.03	0.05
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.78	0.01	0.05	0.06	0.10
Mesa Verde NP	CO	MEVE1	0.38	0.03	0.05	0.05	0.11
Mount Zirkel Wilderness	CO	MOZI1	0.82	0.01	0.09	0.09	0.12
Pecos Wilderness ²	NM	BAND1	0.49	0.04	0.08	0.09	0.33
Petrified Forest NP	AZ	PEFO1	0.43	0.02	0.04	0.04	0.17
Rawah Wilderness	CO	MOZI1	0.83	0.01	0.09	0.09	0.14
Rocky Mountain NP	CO	ROMO1	0.89	0.01	0.06	0.06	0.12
Salt Creek	NM	SACR1	-0.22	0.01	0.01	0.01	0.03
San Pedro Parks Wilderness	NM	SAPE1	0.71	0.12	0.14	0.14	0.18
West Elk Wilderness	CO	WHRI1	0.60	0.02	0.07	0.07	0.11
Weminuche Wilderness	CO	WEMI1	0.47	0.02	0.03	0.03	0.06
Wheeler Peak Wilderness ²	NM	BAND1	0.52	0.09	0.25	0.28	0.45
White Mountain Wilderness	NM	WHIT1	-0.23	0.00	0.00	0.00	0.02

Table 5-25a. Cumulative visibility results for B20% visibility days at Class I areas for current year (2008) and 2021 High Development Scenario using all emissions and without Source Groups R, S, T and U.

Class I Name		IMPROVE Site	2008 Base	2021 High	2021 High w/o R	2021 High w/o S	2021 High w/o T	2021 High w/o U
Arches NP	UT	CANY1	2.86	2.86	2.85	2.81	2.81	2.78
Mount Baldy Wilderness	AZ	BALD1	2.86	2.84	2.83	2.83	2.83	2.80
Bandelier NM	NM	BAND1	4.01	4.62	4.57	4.53	4.51	3.82
Black Canyon of the Gunnison NM	CO	WEMI1	2.25	2.18	2.17	2.07	2.07	2.04
Bosque del Apache	NM	BOAP1	5.50	5.42	5.42	5.42	5.42	5.41
Canyonlands NP	UT	CANY1	4.54	4.72	4.69	4.62	4.62	4.57
Capitol Reef NP	UT	CAPI1	3.33	3.43	3.41	3.37	3.36	3.33
Eagles Nest Wilderness	CO	WHRI1	0.69	0.55	0.54	0.50	0.50	0.48
Flat Tops Wilderness	CO	WHRI1	0.69	0.55	0.53	0.41	0.41	0.38
Galiuro Wilderness ¹	AZ	GICL1	2.58	2.87	2.86	2.86	2.86	2.86
Gila Wilderness	NM	CHIR1	2.58	2.89	2.89	2.89	2.89	2.89
Great Sand Dunes NM	CO	GRSA1	3.58	3.82	3.77	3.75	3.74	3.70
La Garita Wilderness	CO	WEMI1	2.25	2.29	2.27	2.26	2.26	2.22
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.69	0.53	0.51	0.49	0.49	0.47
Mesa Verde NP	CO	MEVE1	3.12	3.28	3.24	3.21	3.21	3.14
Mount Zirkel Wilderness	CO	MOZI1	0.95	0.84	0.83	0.72	0.72	0.68
Pecos Wilderness ²	NM	PEFO1	4.54	4.65	4.60	4.57	4.56	4.21
Petrified Forest NP	AZ	BAND1	4.01	4.51	4.45	4.40	4.39	3.94
Rawah Wilderness	CO	MOZI1	0.95	0.87	0.86	0.75	0.75	0.71
Rocky Mountain NP	CO	ROMO1	1.91	1.87	1.86	1.82	1.82	1.80
Salt Creek	NM	SACR1	6.81	7.00	7.00	7.00	7.00	6.99
San Pedro Parks Wilderness	NM	SAPF1	1.28	1.32	1.18	1.16	1.16	1.11
West Elk Wilderness	CO	WHRI1	0.69	0.57	0.56	0.54	0.54	0.52
Weminuche Wilderness	CO	WEMI1	2.25	2.43	2.40	2.38	2.38	2.35
Wheeler Peak Wilderness ²	NM	BAND1	4.01	4.37	4.21	4.04	3.97	3.75
White Mountain Wilderness	NM	WHIT1	3.33	3.32	3.32	3.32	3.32	3.29

Table 5-25b. Differences in cumulative visibility results for B20% visibility days at Class I areas between current year (2008) and 2021 High Development Scenario (2008-2021) and contributions of Source Groups R, S, T and U to 2021 W20% day's visibility.

Class I Name		IMPROVE Site	2021 High Improvement from 2008	Contribution from R	Contribution from S	Contribution from T	Contribution from U
Arches NP	UT	CANY1	0.00	0.01	0.05	0.05	0.08
Mount Baldy Wilderness	AZ	BALD1	0.02	0.01	0.01	0.01	0.04
Bandelier NM	NM	BAND1	-0.61	0.05	0.09	0.11	0.80
Black Canyon of the Gunnison NM	CO	WEMI1	0.07	0.01	0.11	0.11	0.14
Bosque del Apache	NM	BOAP1	0.08	0.00	0.00	0.00	0.01
Canyonlands NP	UT	CANY1	-0.18	0.03	0.10	0.10	0.15
Capitol Reef NP	UT	CAPI1	-0.10	0.02	0.06	0.07	0.10
Eagles Nest Wilderness	CO	WHRI1	0.14	0.01	0.05	0.05	0.07
Flat Tops Wilderness	CO	WHRI1	0.14	0.02	0.14	0.14	0.17
Galiuro Wilderness ¹	AZ	GICL1	-0.29	0.01	0.01	0.01	0.01
Gila Wilderness	NM	CHIR1	-0.31	0.00	0.00	0.00	0.00
Great Sand Dunes NM	CO	GRSA1	-0.24	0.05	0.07	0.08	0.12
La Garita Wilderness	CO	WEMI1	-0.04	0.02	0.03	0.03	0.07
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.16	0.02	0.04	0.04	0.06
Mesa Verde NP	CO	MEVE1	-0.16	0.04	0.07	0.07	0.14
Mount Zirkel Wilderness	CO	MOZI1	0.11	0.01	0.12	0.12	0.16
Pecos Wilderness ²	NM	PEFO1	-0.11	0.05	0.08	0.09	0.44
Petrified Forest NP	AZ	BAND1	-0.50	0.06	0.11	0.12	0.57
Rawah Wilderness	CO	MOZI1	0.08	0.01	0.12	0.12	0.16
Rocky Mountain NP	CO	ROMO1	0.04	0.01	0.05	0.05	0.07
Salt Creek	NM	SACR1	-0.19	0.00	0.00	0.00	0.01
San Pedro Parks Wilderness	NM	SAPF1	-0.04	0.14	0.16	0.16	0.21
West Elk Wilderness	CO	WHRI1	0.12	0.01	0.03	0.03	0.05
Weminuche Wilderness	CO	WEMI1	-0.18	0.03	0.05	0.05	0.08
Wheeler Peak Wilderness ²	NM	BAND1	-0.36	0.16	0.33	0.40	0.62
White Mountain Wilderness	NM	WHIT1	0.01	0.00	0.00	0.00	0.03

Table 5-26a. Cumulative visibility results for B20% visibility days at Class I areas for current year (2008) and 2021 Low Development Scenario using all emissions and without Source Groups R, S, T and U.

Class I Name		IMPROVE Site	2008 Base	2021 Low	2021 Low w/o R	2021 Low w/o S	2021 Low w/o T	2021 Low w/o U
Arches NP	UT	CANY1	2.86	2.84	2.84	2.82	2.82	2.79
Mount Baldy Wilderness	AZ	BALD1	2.86	2.83	2.83	2.83	2.83	2.80
Bandelier NM	NM	BAND1	4.01	4.58	4.56	4.54	4.53	3.83
Black Canyon of the Gunnison NM	CO	WEMI1	2.25	2.13	2.12	2.08	2.08	2.05
Bosque del Apache	NM	BOAP1	5.50	5.42	5.42	5.42	5.42	5.41
Canyonlands NP	UT	CANY1	4.54	4.69	4.67	4.64	4.64	4.59
Capitol Reef NP	UT	CAPI1	3.33	3.41	3.40	3.37	3.37	3.34
Eagles Nest Wilderness	CO	WHRI1	0.69	0.53	0.53	0.51	0.51	0.48
Flat Tops Wilderness	CO	WHRI1	0.69	0.49	0.49	0.42	0.42	0.39
Galiuro Wilderness ¹	AZ	GICL1	2.58	2.86	2.86	2.86	2.86	2.86
Gila Wilderness	NM	CHIR1	2.58	2.89	2.89	2.89	2.89	2.89
Great Sand Dunes NM	CO	GRSA1	3.58	3.80	3.77	3.76	3.75	3.70
La Garita Wilderness	CO	WEMI1	2.25	2.28	2.27	2.26	2.26	2.22
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.69	0.51	0.51	0.50	0.50	0.48
Mesa Verde NP	CO	MEVE1	3.12	3.25	3.24	3.22	3.22	3.14
Mount Zirkel Wilderness	CO	MOZI1	0.95	0.79	0.78	0.73	0.73	0.69
Pecos Wilderness ²	NM	PEFO1	4.54	4.61	4.60	4.58	4.57	4.21
Petrified Forest NP	AZ	BAND1	4.01	4.46	4.44	4.41	4.40	3.95
Rawah Wilderness	CO	MOZI1	0.95	0.82	0.82	0.77	0.77	0.72
Rocky Mountain NP	CO	ROMO1	1.91	1.85	1.84	1.82	1.82	1.80
Salt Creek	NM	SACR1	6.81	7.00	7.00	7.00	7.00	6.99
San Pedro Parks Wilderness	NM	SAP11	1.28	1.30	1.17	1.17	1.17	1.12
West Elk Wilderness	CO	WHRI1	0.69	0.56	0.55	0.54	0.54	0.52
Weminuche Wilderness	CO	WEMI1	2.25	2.41	2.40	2.39	2.39	2.35
Wheeler Peak Wilderness ²	NM	BAND1	4.01	4.22	4.16	4.06	3.99	3.76
White Mountain Wilderness	NM	WHIT1	3.33	3.32	3.32	3.32	3.32	3.29

Table 5-26b. Differences in cumulative visibility results for B20% visibility days at Class I areas between current year (2008) and 2021 Low Development Scenario (2008-2021) and contributions of Source Groups R, S, T and U to 2021 W20% day's visibility.

Class I Name		IMPROVE Site	2021 Low Improvement from 2008	Contribution from R	Contribution from S	Contribution from T	Contribution from U
Arches NP	UT	CANY1	0.02	0.00	0.02	0.02	0.05
Mount Baldy Wilderness	AZ	BALD1	0.03	0.00	0.00	0.00	0.03
Bandelier NM	NM	BAND1	-0.57	0.02	0.04	0.05	0.75
Black Canyon of the Gunnison NM	CO	WEMI1	0.12	0.01	0.05	0.05	0.08
Bosque del Apache	NM	BOAP1	0.08	0.00	0.00	0.00	0.01
Canyonlands NP	UT	CANY1	-0.15	0.02	0.05	0.05	0.10
Capitol Reef NP	UT	CAPI1	-0.08	0.01	0.04	0.04	0.07
Eagles Nest Wilderness	CO	WHRI1	0.16	0.00	0.02	0.02	0.05
Flat Tops Wilderness	CO	WHRI1	0.20	0.00	0.07	0.07	0.10
Galiuro Wilderness ¹	AZ	GICL1	-0.28	0.00	0.00	0.00	0.00
Gila Wilderness	NM	CHIR1	-0.31	0.00	0.00	0.00	0.00
Great Sand Dunes NM	CO	GRSA1	-0.22	0.03	0.04	0.05	0.10
La Garita Wilderness	CO	WEMI1	-0.03	0.01	0.02	0.02	0.06
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.18	0.00	0.01	0.01	0.03
Mesa Verde NP	CO	MEVE1	-0.13	0.01	0.03	0.03	0.11
Mount Zirkel Wilderness	CO	MOZI1	0.16	0.01	0.06	0.06	0.10
Pecos Wilderness ²	NM	PEFO1	-0.07	0.01	0.03	0.04	0.40
Petrified Forest NP	AZ	BAND1	-0.45	0.02	0.05	0.06	0.51
Rawah Wilderness	CO	MOZI1	0.13	0.00	0.05	0.05	0.10
Rocky Mountain NP	CO	ROMO1	0.06	0.01	0.03	0.03	0.05
Salt Creek	NM	SACR1	-0.19	0.00	0.00	0.00	0.01
San Pedro Parks Wilderness	NM	SAP11	-0.02	0.13	0.13	0.13	0.18
West Elk Wilderness	CO	WHRI1	0.13	0.01	0.02	0.02	0.04
Weminuche Wilderness	CO	WEMI1	-0.16	0.01	0.02	0.02	0.06
Wheeler Peak Wilderness ²	NM	BAND1	-0.21	0.06	0.16	0.23	0.46
White Mountain Wilderness	NM	WHIT1	0.01	0.00	0.00	0.00	0.03

Table 5-27a. Cumulative visibility results for B20% visibility days at Class I areas for current year (2008) and 2021 Medium Development Scenario using all emissions and without Source Groups R, S, T and U.

Class I Name		IMPROVE Site	2008 Base	2021 Medium	2021 Med w/o R	2021 Med w/o S	2021 Med w/o T	2021 Med w/o U
Arches NP	UT	CANY1	2.86	2.86	2.85	2.81	2.81	2.78
Mount Baldy Wilderness	AZ	BALD1	2.86	2.83	2.83	2.83	2.83	2.80
Bandelier NM	NM	BAND1	4.01	4.62	4.57	4.52	4.52	3.82
Black Canyon of the Gunnison NM	CO	WEMI1	2.25	2.18	2.17	2.07	2.07	2.04
Bosque del Apache	NM	BOAP1	5.50	5.42	5.42	5.42	5.42	5.41
Canyonlands NP	UT	CANY1	4.54	4.72	4.69	4.62	4.62	4.58
Capitol Reef NP	UT	CAPI1	3.33	3.43	3.41	3.37	3.36	3.33
Eagles Nest Wilderness	CO	WHRI1	0.69	0.55	0.54	0.50	0.50	0.48
Flat Tops Wilderness	CO	WHRI1	0.69	0.54	0.53	0.41	0.41	0.38
Galiuro Wilderness ¹	AZ	GICL1	2.58	2.87	2.86	2.86	2.86	2.86
Gila Wilderness	NM	CHIR1	2.58	2.89	2.89	2.89	2.89	2.89
Great Sand Dunes NM	CO	GRSA1	3.58	3.81	3.77	3.75	3.75	3.70
La Garita Wilderness	CO	WEMI1	2.25	2.29	2.27	2.26	2.26	2.22
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.69	0.52	0.51	0.49	0.49	0.47
Mesa Verde NP	CO	MEVE1	3.12	3.27	3.24	3.21	3.21	3.14
Mount Zirkel Wilderness	CO	MOZI1	0.95	0.83	0.83	0.72	0.72	0.68
Pecos Wilderness ²	NM	PEFO1	4.54	4.64	4.60	4.57	4.56	4.21
Petrified Forest NP	AZ	BAND1	4.01	4.50	4.44	4.40	4.39	3.94
Rawah Wilderness	CO	MOZI1	0.95	0.87	0.86	0.75	0.75	0.71
Rocky Mountain NP	CO	ROMO1	1.91	1.87	1.86	1.82	1.82	1.80
Salt Creek	NM	SACR1	6.81	7.00	7.00	7.00	7.00	6.99
San Pedro Parks Wilderness	NM	SAPF1	1.28	1.32	1.18	1.16	1.16	1.11
West Elk Wilderness	CO	WHRI1	0.69	0.57	0.56	0.54	0.54	0.52
Weminuche Wilderness	CO	WEMI1	2.25	2.43	2.40	2.38	2.38	2.35
Wheeler Peak Wilderness ²	NM	BAND1	4.01	4.32	4.19	4.02	3.97	3.75
White Mountain Wilderness	NM	WHIT1	3.33	3.32	3.32	3.32	3.32	3.29

Table 5-27b. Differences in cumulative visibility results for B20% visibility days at Class I areas between current year (2008) and 2021 Medium Development Scenario (2008-2021) and contributions of Source Groups R, S, T and U to 2021 W20% day's visibility.

Class I Name		IMPROVE Site	2021 Med Improvement from 2008	Contribution from R	Contribution from S	Contribution from T	Contribution from U
Arches NP	UT	CANY1	0.00	0.01	0.05	0.05	0.08
Mount Baldy Wilderness	AZ	BALD1	0.03	0.00	0.00	0.00	0.03
Bandelier NM	NM	BAND1	-0.61	0.05	0.10	0.10	0.80
Black Canyon of the Gunnison NM	CO	WEMI1	0.07	0.01	0.11	0.11	0.14
Bosque del Apache	NM	BOAP1	0.08	0.00	0.00	0.00	0.01
Canyonlands NP	UT	CANY1	-0.18	0.03	0.10	0.10	0.14
Capitol Reef NP	UT	CAPI1	-0.10	0.02	0.06	0.07	0.10
Eagles Nest Wilderness	CO	WHRI1	0.14	0.01	0.05	0.05	0.07
Flat Tops Wilderness	CO	WHRI1	0.15	0.01	0.13	0.13	0.16
Galiuro Wilderness ¹	AZ	GICL1	-0.29	0.01	0.01	0.01	0.01
Gila Wilderness	NM	CHIR1	-0.31	0.00	0.00	0.00	0.00
Great Sand Dunes NM	CO	GRSA1	-0.23	0.04	0.06	0.06	0.11
La Garita Wilderness	CO	WEMI1	-0.04	0.02	0.03	0.03	0.07
Maroon Bells-Snowmass Wilderness	CO	WHRI1	0.17	0.01	0.03	0.03	0.05
Mesa Verde NP	CO	MEVE1	-0.15	0.03	0.06	0.06	0.13
Mount Zirkel Wilderness	CO	MOZI1	0.12	0.00	0.11	0.11	0.15
Pecos Wilderness ²	NM	PEFO1	-0.10	0.04	0.07	0.08	0.43
Petrified Forest NP	AZ	BAND1	-0.49	0.06	0.10	0.11	0.56
Rawah Wilderness	CO	MOZI1	0.08	0.01	0.12	0.12	0.16
Rocky Mountain NP	CO	ROMO1	0.04	0.01	0.05	0.05	0.07
Salt Creek	NM	SACR1	-0.19	0.00	0.00	0.00	0.01
San Pedro Parks Wilderness	NM	SAPF1	-0.04	0.14	0.16	0.16	0.21
West Elk Wilderness	CO	WHRI1	0.12	0.01	0.03	0.03	0.05
Weminuche Wilderness	CO	WEMI1	-0.18	0.03	0.05	0.05	0.08
Wheeler Peak Wilderness ²	NM	BAND1	-0.31	0.13	0.30	0.35	0.57
White Mountain Wilderness	NM	WHIT1	0.01	0.00	0.00	0.00	0.03

5.4 Sulfur and Nitrogen Deposition at Class I and Sensitive Class II Areas

Attachments D-1, D-2 and D-3 are interactive Excel spreadsheets that display Maximum and Average sulfur and nitrogen deposition due to emissions from each of the 24 Source Groups shown in Table 4-2. As for the PSD concentrations Attachment A spreadsheet, there is a “Summary” sheet that displays the sulfur and nitrogen deposition across all Class I and sensitive Class II areas for a user selected Source Group that is controlled by a drop down menu in cell B5. And a “MaxImpact” sheet that gives the highest sulfur or nitrogen deposition that occurred at any Class I area or sensitive Class II area that is controlled by cell B3 to select Sulfur or Nitrogen and cell B4 to select either Maximum or Average. Here Maximum represents the maximum deposition in any grid cell covering the Class I/II area, whereas Average provides the average of deposition across all grid cells covering a Class I/II area. Although the convention in the past has been to report the Maximum deposition in any receptor in a Class I/II area, since deposition relates to the total amount deposited across an entire watershed, the Average metric is probably a more relevant parameter for evaluating potential environment effects. Both Maximum and Average deposition metrics are reported.

For the deposition impacts associated with Federal O&G within each of the individual BLM Planning Areas (i.e., Source Groups A through P), the sulfur and nitrogen deposition amounts are compared against the 0.005 kg/ha/yr Deposition Analysis Threshold (DAT) for the western U.S.. The DAT is a screening threshold where if a Project’s deposition amount is below the DAT then its deposition impacts is considered insignificant. The deposition due to the total emission scenarios, that is Source Groups W (2021) and X (2008), are compared against the Critical Load Values, which for nitrogen is 2.2 kg/ha/yr in Wyoming and 2.3 kg/ha/yr in Colorado except for 3.0 kg/ha/yr for Dinosaur NM and for sulfur is 5.0 kg/ha/yr everywhere.

5.4.1 Highest Deposition Impacts at Class I/II Areas

Tables 5-29 through 5-31 display the highest Maximum and Average nitrogen and sulfur deposition in any Class I or sensitive Class II area due to emissions from each of the 24 Source Groups for the, respectively 2021 High, Low and Medium Development Scenarios. The results for the GJFO, UFO and USFS-PG Planning Areas are summarized in Table 5-28.

5.4.1.1 Individual BLM Planning Area Comparison to DATs

Individual BLM Planning Area (i.e., Source Groups A through P) annual nitrogen and sulfur deposition are compared against the 0.005 kg/ha/yr western U.S. Deposition Analysis Threshold (DAT). The two BLM Planning Area with Federal O&G having the highest annual nitrogen deposition impact are the TRFO and WRFO with Maximum values of 0.126 and 0.108 and Average values of 0.043 and 0.068 for the High, Maximum values of 0.106 and 0.134 and Average values of 0.036 and 0.056 for the Medium, and Maximum values of 0.015 and 0.017 and Average values of 0.005 and 0.011 for the Low Development Scenarios all of which are above the DAT (Tables 5-29 through 5-31).

Table 5-28 summarizes the Average and Maximum nitrogen and sulfur deposition results for new Federal O&G emissions from the Grand Junction Field Office (GJFO), Uncompahgre Field Office (UFO) and Pawnee Grassland (USFS-PG) Planning Areas and the 2021 High, Low and Medium Development Scenarios. For the 2021 High Development Scenario, the highest

Maximum and Average nitrogen deposition at any Class I area due to GJFO (0.0679 and 0.0416 kg/ha/yr) and UFO (0.0240 and 0.0104 kg/ha/yr) that are above the DAT. However, for USFS-PG Planning Area, its highest Maximum and Average nitrogen deposition at any Class I area is below the DAT (0.0017 and 0.0006 kg/ha/yr) for the 2021 High Development Scenario. For the 2021 Low Development Scenario, the Maximum and Average nitrogen deposition for GJFO (0.0037 and 0.0023 kg/ha/yr) are below the DAT. And for UFO the Maximum value (0.0065 kg/ha/yr) is above but the Average value (0.0027 kg/ha/yr) is below the DAT. The nitrogen deposition results for the Medium Scenario falls between the High and Low Scenarios.

The annual sulfur deposition from new Federal O&G in the BLM Planning Areas tends to be much lower than seen for the nitrogen deposition so results for just the 2021 High Development Scenario and Maximum sulfur deposition metric are presented in Table 5-32 with the other results provided in Attachments D-1, D-2 and D-3. The only individual BLM Planning Area whose new Federal O&G emissions results in its sulfur deposition exceeding the DAT is the WRFO and that is just for the Maximum (0.011 kg/ha/yr) and Average (0.008 kg/ha/yr) 2021 High Development Scenario. The Maximum (0.021 kg/ha/yr) and Average (0.008 kg/ha/yr) sulfur deposition due to WRFO for the 2021 Medium Development Scenario are also above the DAT. However, the highest WRFO sulfur deposition for the Maximum (0.002 kg/ha/yr) and Average (0.001 kg/ha/yr) metrics and the 2021 Low Development Scenario are below the DAT. The sulfur deposition results for all the other individual BLM Planning areas are below the DAT. For example, Table 5-28b displays the highest Maximum and Average sulfur deposition results at any Class I or II area due to new Federal O&G emissions from the GJFO, UFO and USFS-PG Planning Areas and all values are approximately a factor of 10 or more below the DAT.

Table 5-28a. Highest maximum and average nitrogen deposition (kg/ha/yr) at any Class I or sensitive Class II area due to new Federal oil and gas emissions from the BLM Grand Junction Field Office and Uncompahgre Field Office and the USFS Pawnee Grassland Planning Areas for the 2021 High, Low and Medium Development Scenarios.

Source Group	Class I Areas			Sensitive Class II Areas		
	Max	Avg	Area	Max	Avg	Area
2021 High Development Scenario						
GJFO	0.0679	0.0416	Maroon-B	0.0679	0.0543	Colorado NM
UFO	0.0240	0.0104	Maroon-B	0.0347	0.0151	Raggeds
USFS-PG	0.0017	0.006	Rocky Mtn	0.0013	0.0007	Mt. Evans
2021 Low Development Scenario						
GJFO	0.0037	0.0023	Maroon-B	0.0037	0.0029	Colorado NM
UFO	0.0065	0.0027	Maroon-B	0.0100	0.0400	Raggeds Gun
USFS-PG	0.0004	0.0001	Rocky Mtn	0.0003	0.0002	Mt. Evans
2021 Medium Development Scenario						
GJFO	0.0558	0.0344	Maroon-B	0.06071	0.0483	Colorado NM
UFO	0.0167	0.0076	Maroon-B	0.0241	0.0109	Raggeds Gun
USFS-PG	0.0011	0.0004	Rocky Mtn	0.0008	0.0005	Mt. Evans

Table 5-28b. Highest maximum and average sulfur deposition (kg/ha/yr) at any Class I or sensitive Class II area due to new Federal oil and gas emissions from the BLM Grand Junction Field Office and Uncompahgre Field Office and the USFS Pawnee Grassland Planning Areas for the 2021 High, Low and Medium Development Scenarios.

Source Group	Class I Areas			Sensitive Class II Areas		
	Max	Avg	Area	Max	Avg	Area
2021 High Development Scenario						
GJFO	0.0006	0.0004	Maroon-B	0.0005	0.0003	Raggeds
UFO	0.0004	0.0002	Maroon-B	0.0008	0.0003	Raggeds
USFS-PG	0.0000	0.0000	Rocky Mtn	0.0000	0.0000	Lost Creek
2021 Low Development Scenario						
GJFO	0.0001	0.0000	Maroon-B	0.0000	0.0000	Raggeds
UFO	0.0001	0.0001	Maroon-B	0.0002	0.0001	Raggeds
USFS-PG	0.0000	0.0000	Rocky Mtn	0.0000	0.0000	Lost Creek
2021 Medium Development Scenario						
GJFO	0.0005	0.0003	Maroon-B	0.0004	0.0002	Raggeds
UFO	0.0003	0.0001	Maroon-B	0.0006	0.0002	Raggeds
USFS-PG	0.0000	0.0000	Rocky Mtn	0.0000	0.0000	Lost Creek

Table 5-29a. Highest nitrogen deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 High Development Scenario using the Maximum deposition in any receptor in the Class I/II area.

Choose	Nitrogen				
Across grid cells	Maximum				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0169	Mount_Zirkel	0.0136	Dinosaur_all
B	White River FO	0.1083	Flat_Tops	0.1418	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0198	Flat_Tops	0.0118	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0200	Flat_Tops	0.0107	Holy_Cross
E	Grand Junction FO	0.0679	Maroon_Bells	0.0679	Colorado
F	Uncompahgre FO	0.0240	Maroon_Bells	0.0347	Raggeds
G	Tres Rios FO	0.1256	Mesa_Verde	0.1448	South_San_Juan
H	Kremmling FO	0.0065	Rawah	0.0022	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0004	Rocky_Mountain	0.0003	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	0.0017	Rocky_Mountain	0.0013	Mount_Evans
K	RGFO#2 – West-Central/South	0.0005	Pecos	0.0008	Las_Vegas_NWR
L	RGFO#3 – South	0.0017	Great_Sand_Dunes	0.0272	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0002	Eagles_Nest	0.0028	Lost_Creek
N	New Mexico Farmington District	0.0371	Weminuche	0.1607	Aztec_Ruins
O	Total Colorado River Field Office	0.0398	Flat_Tops	0.0225	Holy_Cross
P	Total Royal Gorge Field Office	0.0024	Rocky_Mountain	0.0279	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0086	Mount_Zirkel	0.0062	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.2120	Flat_Tops	0.1762	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.3660	Flat_Tops	0.3388	South_San_Juan
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.3680	Flat_Tops	0.3746	South_San_Juan
U	Combined O&G and Mining in 4 km domain	0.5946	Mesa_Verde	1.9374	Aztec_Ruins
V	Natural Emissions	6.6543	Bandelier	1.4498	Chama_River_Cany
W	All 2021 Emissions	8.4676	Bandelier	11.2607	Valle_De_Oro_NWR
X	All 2008 Emissions	9.0012	Bandelier	12.6927	Bitter_Lake_NWR

Table 5-29b. Highest nitrogen deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 High Development Scenario using the Average deposition in any receptor in the Class I/II area.

Choose	Nitrogen				
Across grid cells	Average				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0133	Mount_Zirkel	0.0079	Savage_Run
B	White River FO	0.0680	Flat_Tops	0.0390	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0120	Flat_Tops	0.0082	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0120	Flat_Tops	0.0075	Holy_Cross
E	Grand Junction FO	0.0416	Maroon_Bells	0.0543	Colorado
F	Uncompahgre FO	0.0104	Maroon_Bells	0.0151	Raggeds
G	Tres Rios FO	0.0428	Mesa_Verde	0.0466	Hovenweep
H	Kremmling FO	0.0031	Rawah	0.0015	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0001	Rocky_Mountain	0.0002	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	0.0006	Rocky_Mountain	0.0007	Lost_Creek
K	RGFO#2 – West-Central/South	0.0003	Salt_Creek	0.0006	Maxwell_NWR
L	RGFO#3 – South	0.0011	Great_Sand_Dunes	0.0133	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0001	Eagles_Nest	0.0017	Lost_Creek
N	New Mexico Farmington District	0.0242	Mesa_Verde	0.1501	Aztec_Ruins
O	Total Colorado River Field Office	0.0241	Flat_Tops	0.0157	Holy_Cross
P	Total Royal Gorge Field Office	0.0014	Great_Sand_Dunes	0.0147	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0051	Mount_Zirkel	0.0050	Colorado
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.1454	Flat_Tops	0.1160	Colorado
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.2550	Flat_Tops	0.2191	Colorado
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.2566	Flat_Tops	0.2552	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	0.4902	Mesa_Verde	1.9175	Aztec_Ruins
V	Natural Emissions	0.7876	Bandelier	0.4469	Dome
W	All 2021 Emissions	3.1160	Mount_Zirkel	8.8528	Valle_De_Oro_NWR
X	All 2008 Emissions	5.3938	Salt_Creek	10.0402	Valle_De_Oro_NWR

Table 5-30a. Highest nitrogen deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 Low Development Scenario using the Maximum deposition in any receptor in the Class I/II area.

Choose	Nitrogen				
Across grid cells	Maximum				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0023	Mount_Zirkel	0.0018	Dinosaur_all
B	White River FO	0.0169	Flat_Tops	0.0228	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0122	Flat_Tops	0.0072	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0101	Flat_Tops	0.0053	Holy_Cross
E	Grand Junction FO	0.0037	Maroon_Bells	0.0037	Colorado
F	Uncompahgre FO	0.0065	Maroon_Bells	0.0100	Raggeds
G	Tres Rios FO	0.0153	Mesa_Verde	0.0182	South_San_Juan
H	Kremmling FO	0.0007	Rawah	0.0002	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0001	Rocky_Mountain	0.0001	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	0.0004	Rocky_Mountain	0.0003	Mount_Evans
K	RGFO#2 – West-Central/South	0.0000	Pecos	0.0001	Las_Vegas_NWR
L	RGFO#3 – South	0.0011	Great_Sand_Dunes	0.0169	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0000	Eagles_Nest	0.0004	Lost_Creek
N	New Mexico Farmington District	0.0371	Weminuche	0.1605	Aztec_Ruins
O	Total Colorado River Field Office	0.0223	Flat_Tops	0.0125	Holy_Cross
P	Total Royal Gorge Field Office	0.0011	Great_Sand_Dunes	0.0170	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0085	Mount_Zirkel	0.0061	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.0434	Flat_Tops	0.0315	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.2000	Mesa_Verde	0.2128	South_San_Juan
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.2156	Mesa_Verde	0.2487	South_San_Juan
U	Combined O&G and Mining in 4 km domain	0.5434	Mesa_Verde	1.9167	Aztec_Ruins
V	Natural Emissions	6.6543	Bandelier	1.4498	Chama_River_Cany
W	All 2021 Emissions	8.4513	Bandelier	11.2549	Valle_De_Oro_NWR
X	All 2008 Emissions	9.0012	Bandelier	12.6927	Bitter_Lake_NWR

Table 5-30b. Highest nitrogen deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 Low Development Scenario using the Average deposition in any receptor in the Class I/II area.

Choose	Nitrogen				
Across grid cells	Average				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0018	Mount_Zirkel	0.0011	Savage_Run
B	White River FO	0.0107	Flat_Tops	0.0061	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0074	Flat_Tops	0.0050	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0060	Flat_Tops	0.0037	Holy_Cross
E	Grand Junction FO	0.0023	Flat_Tops	0.0029	Colorado
F	Uncompahgre FO	0.0027	Maroon_Bells	0.0040	Raggeds
G	Tres Rios FO	0.0052	Mesa_Verde	0.0056	Hovenweep
H	Kremmling FO	0.0003	Rawah	0.0002	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0000	Rocky_Mountain	0.0000	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	0.0001	Rocky_Mountain	0.0002	Lost_Creek
K	RGFO#2 – West-Central/South	0.0000	Salt_Creek	0.0001	Maxwell_NWR
L	RGFO#3 – South	0.0007	Great_Sand_Dunes	0.0083	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0000	Eagles_Nest	0.0002	Lost_Creek
N	New Mexico Farmington District	0.0242	Mesa_Verde	0.1499	Aztec_Ruins
O	Total Colorado River Field Office	0.0134	Flat_Tops	0.0087	Holy_Cross
P	Total Royal Gorge Field Office	0.0007	Great_Sand_Dunes	0.0085	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0051	Mount_Zirkel	0.0049	Colorado
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.0303	Flat_Tops	0.0216	Raggeds
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.0841	Flat_Tops	0.0973	Hovenweep
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.1058	Mesa_Verde	0.2348	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	0.4345	Mesa_Verde	1.8948	Aztec_Ruins
V	Natural Emissions	0.7876	Bandelier	0.4469	Dome
W	All 2021 Emissions	2.9682	Mount_Zirkel	8.8463	Valle_De_Oro_NWR
X	All 2008 Emissions	5.3938	Salt_Creek	10.0402	Valle_De_Oro_NWR

Table 5-31a. Highest nitrogen deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 Medium Development Scenario using the Maximum deposition in any receptor in the Class I/II area.

Choose	Nitrogen				
Across grid cells	Maximum				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0153	Mount_Zirkel	0.0118	Dinosaur_all
B	White River FO	0.1343	Dinosaur_CO	0.1343	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0156	Flat_Tops	0.0097	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0163	Flat_Tops	0.0089	Holy_Cross
E	Grand Junction FO	0.0558	Maroon_Bells	0.0607	Colorado
F	Uncompahgre FO	0.0167	Maroon_Bells	0.0241	Raggeds
G	Tres Rios FO	0.1062	Mesa_Verde	0.1230	South_San_Juan
H	Kremmling FO	0.0040	Rawah	0.0015	Mount_Evans
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0003	Rocky_Mountain	0.0002	Mount_Evans
J	Pawnee Grasslands portion of RGFO#1	0.0011	Rocky_Mountain	0.0008	Mount_Evans
K	RGFO#2 – West-Central/South	0.0004	Pecos	0.0006	Las_Vegas_NWR
L	RGFO#3 – South	0.0012	Great_Sand_Dunes	0.0190	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0001	Eagles_Nest	0.0016	Lost_Creek
N	New Mexico Farmington District	0.0285	Weminuche	0.1236	Aztec_Ruins
O	Total Colorado River Field Office	0.0320	Flat_Tops	0.0186	Holy_Cross
P	Total Royal Gorge Field Office	0.0015	Rocky_Mountain	0.0195	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0086	Mount_Zirkel	0.0062	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.1739	Flat_Tops	0.1639	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.3200	Flat_Tops	0.3105	South_San_Juan
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.3216	Flat_Tops	0.3380	South_San_Juan
U	Combined O&G and Mining in 4 km domain	0.6433	Dinosaur_CO	1.8955	Aztec_Ruins
V	Natural Emissions	6.6543	Bandelier	1.4498	Chama_River_Cany
W	All 2021 Emissions	8.4636	Bandelier	11.2595	Valle_De_Oro_NWR
X	All 2008 Emissions	9.0012	Bandelier	12.6927	Bitter_Lake_NWR

Table 5-31b. Highest nitrogen deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 Medium Development Scenario using the Average deposition in any receptor in the Class I/II area.

Choose	Nitrogen				
Across grid cells	Average				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0120	Mount_Zirkel	0.0070	Savage_Run
B	White River FO	0.0559	Flat_Tops	0.0374	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0095	Flat_Tops	0.0068	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0098	Flat_Tops	0.0062	Holy_Cross
E	Grand Junction FO	0.0344	Maroon_Bells	0.0483	Colorado
F	Uncompahgre FO	0.0076	Maroon_Bells	0.0109	Raggeds
G	Tres Rios FO	0.0363	Mesa_Verde	0.0396	Hovenweep
H	Kremmling FO	0.0020	Rawah	0.0010	Mount_Evans
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0001	Rocky_Mountain	0.0001	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	0.0004	Rocky_Mountain	0.0005	Lost_Creek
K	RGFO#2 – West-Central/South	0.0003	Salt_Creek	0.0004	Maxwell_NWR
L	RGFO#3 – South	0.0008	Great_Sand_Dunes	0.0093	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0000	Eagles_Nest	0.0009	Lost_Creek
N	New Mexico Farmington District	0.0185	Mesa_Verde	0.1154	Aztec_Ruins
O	Total Colorado River Field Office	0.0193	Flat_Tops	0.0129	Holy_Cross
P	Total Royal Gorge Field Office	0.0010	Great_Sand_Dunes	0.0102	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0051	Mount_Zirkel	0.0050	Colorado
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.1199	Flat_Tops	0.1027	Colorado
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.2240	Flat_Tops	0.2027	Colorado
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.2253	Flat_Tops	0.2145	Aztec_Ruins
U	Combined O&G and Mining in 4 km domain	0.4729	Mesa_Verde	1.8770	Aztec_Ruins
V	Natural Emissions	0.7876	Bandelier	0.4469	Dome
W	All 2021 Emissions	3.0955	Mount_Zirkel	8.8515	Valle_De_Oro_NWR
X	All 2008 Emissions	5.3938	Salt_Creek	10.0402	Valle_De_Oro_NWR

Table 5-32. Highest sulfur deposition at any Class I area or sensitive Class II area for each of the 24 Source Groups and the 2021 High Development Scenario using the Maximum deposition in any receptor in the Class I/II area.

Choose	Sulfur				
Across grid cells	Maximum				
Group	Group Name	Max @ any Class I area	Class I Area where Max occurred	Max @ any Class II area	Class II Area where Max occurred
A	Little Snake FO	0.0003	Mount_Zirkel	0.0001	Savage_Run
B	White River FO	0.0111	Flat_Tops	0.0212	Dinosaur_all
C	Colorado River Valley FO (CRVFO)	0.0003	Flat_Tops	0.0001	Holy_Cross
D	Roan Plateau Planning area portion of CRVFO	0.0002	Flat_Tops	0.0001	Holy_Cross
E	Grand Junction FO	0.0006	Maroon_Bells	0.0005	Raggeds
F	Uncompahgre FO	0.0004	Maroon_Bells	0.0008	Raggeds
G	Tres Rios FO	0.0006	Mesa_Verde	0.0012	South_San_Juan
H	Kremmling FO	0.0001	Rawah	0.0000	Savage_Run
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0000	Rocky_Mountain	0.0000	Lost_Creek
J	Pawnee Grasslands portion of RGFO#1	0.0000	Rocky_Mountain	0.0000	Lost_Creek
K	RGFO#2 – West-Central/South	0.0000	Pecos	0.0000	Greenhorn_Mounta
L	RGFO#3 – South	0.0000	Great_Sand_Dunes	0.0001	Greenhorn_Mounta
M	RGFO#4 – East-Central	0.0000	Eagles_Nest	0.0000	Lost_Creek
N	New Mexico Farmington District	0.0009	Weminuche	0.0019	Aztec_Ruins
O	Total Colorado River Field Office	0.0004	Flat_Tops	0.0002	Holy_Cross
P	Total Royal Gorge Field Office	0.0000	Rocky_Mountain	0.0001	Greenhorn_Mounta
Q	Mining from 13 Colorado BLM Planning Areas	0.0235	Mount_Zirkel	0.0078	Raggeds
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.0323	Mount_Zirkel	0.0229	Dinosaur_all
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	0.0345	Mount_Zirkel	0.0259	Dinosaur_all
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	0.0345	Mount_Zirkel	0.0260	Dinosaur_all
U	Combined O&G and Mining in 4 km domain	0.0411	Mount_Zirkel	0.0300	Dinosaur_all
V	Natural Emissions	0.1642	Bandelier	0.0497	Dome
W	All 2021 Emissions	1.7369	Mount_Baldy	1.4079	South_San_Juan
X	All 2008 Emissions	2.3428	Mount_Zirkel	2.1000	South_San_Juan

5.4.1.2 Comparisons Against Critical Loads

In this section we compare the total sulfur and nitrogen deposition from all sources in the 2008 Base Case and 2021 High, Low and Medium Development Scenarios with Critical Load values. It is unclear what the sulfur and nitrogen for the combined Source Groups Q through U should be compared against given that the DAT and Critical Load LOCs were designed for single Projects and total emissions, respectively. The total nitrogen and sulfur deposition amounts for the combined Source Groups Q through U are much lower than the Critical Load values (Attachments D-1, D-2 and D-3).

Tables 5-33 and 5-34 display the total nitrogen and sulfur deposition, respectively, at Class I areas for the 2021 High, Low and Medium Development Scenarios, the 2008 Base Case, the differences between the three 2021 scenarios and the 2008 Base Case (2021 minus 2008) and the difference between the three 2021 scenarios and the natural emissions (Source Group V). As seen in Table 5-29a the Class I area with the highest Maximum nitrogen deposition in the 2021 High Development Scenario is 8.47 kg/ha/yr at the Bandelier Class I area in New Mexico that is over 3 times the nitrogen Critical Load value (2.3 kg/ha/yr). However, most of this (6.65 kg/ha/yr) is due to natural emissions (Source Group V in Table 5-29a) and when natural emission contributions are removed the value at Bandelier for the 2021 scenarios (1.80-1.81

kg/ha/yr) is reduced to below the nitrogen Critical Load value (2.3 kg/ha/yr) (Table 5-33). When removing natural emission contributions the Maximum nitrogen deposition exceeds the 2.3 kg/ha/yr Critical Load value at approximately half (14) of the 26 Class I areas for all three 2021 emission scenarios with the highest value of 4.23, 4.04 and 4.20 kg/ha/yr at the Mount Zirkel Wilderness Area and the 2021 High, Low and Medium Development Scenarios, respectively. When examining the Average annual nitrogen deposition across Class I areas, approximately a quarter of the Class I areas exceed the 2.3 kg/ha/yr nitrogen Critical Load value for the 2021 emission scenarios..

With one exception, all 26 Class I areas exhibit a reduction in annual nitrogen deposition from 2008 to 2021 with the largest reduction occurring at Salt Creek (-5.5 kg/ha/yr) and the second largest reduction occurring at Bosque del Apache (-2.6 kg/ha/yr). The exception is the Great Sand Dunes NM that saw essentially no change in nitrogen deposition between 2008 and 2021 for the three 2021 emissions scenarios (changes of -0.02 to +0.07 kg/ha/yr).

The total sulfur deposition at all of the Class I areas for the 2008 and three 2021 emission scenarios are all well below the sulfur Critical Load of 5 kg/ha/yr (Table 5-34). Sulfur deposition is reduced by 5% to 50% across the Class I areas between the 2008 and 2021 emissions scenarios. The highest sulfur deposition at any Class I area for the three 2021 emission scenarios is 1.7 kg/ha/yr at Mt. Baldy that is approximately a factor of three below the sulfur deposition Critical Load (5.0 kg/ha/yr) (Table 5-34).

Additional results, including those for sensitive Class II areas and all Source Groups, are found in Attachments D-1, D-2 and D-3.

Table 5-33a. Total annual nitrogen deposition at Class I areas for the 2021 High Development Scenario, 2008 Base Case, their differences (2021 High minus 2008) and 2021 High Development Scenario without the contributions of natural emissions (e.g., wildfires).

Class I Area	2021 High		2008 Base		2021 High - 2008		2021 Hi - Natural	
	N-Max	N-Avg	N-Max	N-Avg	N-Max	N-Avg	N-Max	N-Avg
	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)
Arches NP	1.67	1.56	2.20	1.81	-0.53	-0.25	1.64	1.52
Bandelier NM	8.47	2.51	9.00	2.96	-0.53	-0.45	1.81	1.72
Black Canyon NP	2.85	2.30	2.99	2.57	-0.14	-0.27	2.79	2.25
Bosque del Apache WA	2.49	1.64	5.08	2.46	-2.60	-0.82	2.26	1.51
Canyonlands NP	1.89	1.43	2.31	1.77	-0.42	-0.34	1.84	1.39
Capitol Reef NP	3.22	1.54	3.37	1.90	-0.15	-0.36	3.20	1.52
Eagles Nest WA	2.79	2.08	3.59	2.94	-0.79	-0.85	2.73	2.03
Flat Tops WA	3.00	2.39	3.71	3.09	-0.71	-0.70	2.90	2.34
Galiuro WA	2.39	2.29	2.97	2.83	-0.57	-0.54	2.38	2.28
Gila WA	2.07	1.36	2.69	1.68	-0.63	-0.31	1.98	1.31
Great Sand Dunes NM	2.77	1.97	2.70	1.95	0.07	0.02	2.66	1.89
La Garita WA	1.97	1.55	2.75	2.11	-0.78	-0.56	1.88	1.48
Maroon Bells-Snowmass	3.01	2.18	3.81	2.94	-0.80	-0.77	2.93	2.12
Mesa Verde NP	2.92	2.53	3.14	2.76	-0.21	-0.22	2.86	2.47
Mount Baldy WA	2.38	1.94	3.24	2.69	-0.86	-0.75	2.05	1.70
Mount Zirkel WA	4.29	3.12	5.13	3.95	-0.84	-0.84	4.23	3.07
Pecos WA	2.98	2.27	3.95	2.99	-0.97	-0.72	2.19	2.09
Petrified Forest NP	2.04	1.72	2.66	2.16	-0.62	-0.44	1.99	1.68
Rawah WA	3.23	2.51	4.07	3.27	-0.84	-0.76	3.14	2.45
Rocky Mountain NP	3.41	2.58	4.49	3.50	-1.08	-0.92	3.31	2.51
Salt Creek WA	2.70	2.43	8.21	5.39	-5.51	-2.96	2.64	2.38
San Pedro Parks WA	2.70	2.33	3.36	2.93	-0.67	-0.60	2.25	2.15
Weminuche WA	3.03	2.14	3.80	2.84	-0.78	-0.70	2.89	2.06
West Elk WA	2.58	1.98	3.34	2.63	-0.76	-0.66	2.27	1.91
Wheeler Peak WA	3.10	2.55	4.11	3.44	-1.02	-0.88	2.90	2.41
White Mountain WA	3.09	2.42	3.73	2.85	-0.65	-0.42	2.57	2.14

Table 5-33b. Total annual nitrogen deposition at Class I areas for the 2021 Low Development Scenario, 2008 Base Case, their differences (2021 Low minus 2008) and 2021 Low Development Scenario without the contributions of natural emissions (e.g., wildfires).

Class I Area	2021 Low		2008 Base		2021 Low - 2008		2021 Low - Natural	
	N-Max	N-Avg	N-Max	N-Avg	N-Max	N-Avg	N-Max	N-Avg
	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)
Arches NP	1.59	1.48	2.20	1.81	-0.62	-0.33	1.55	1.44
Bandelier NM	8.45	2.49	9.00	2.96	-0.55	-0.47	1.80	1.70
Black Canyon NP	2.72	2.19	2.99	2.57	-0.26	-0.38	2.67	2.14
Bosque del Apache WA	2.48	1.63	5.08	2.46	-2.60	-0.83	2.26	1.51
Canyonlands NP	1.86	1.40	2.31	1.77	-0.45	-0.37	1.81	1.37
Capitol Reef NP	3.22	1.54	3.37	1.90	-0.15	-0.37	3.19	1.52
Eagles Nest WA	2.61	1.95	3.59	2.94	-0.98	-0.99	2.54	1.90
Flat Tops WA	2.75	2.20	3.71	3.09	-0.96	-0.89	2.66	2.15
Galiuro WA	2.39	2.29	2.97	2.83	-0.58	-0.55	2.38	2.28
Gila WA	2.06	1.36	2.69	1.68	-0.63	-0.31	1.98	1.31
Great Sand Dunes NM	2.72	1.93	2.70	1.95	0.02	-0.02	2.62	1.86
La Garita WA	1.91	1.51	2.75	2.11	-0.83	-0.60	1.82	1.44
Maroon Bells-Snowmass	2.82	2.02	3.81	2.94	-0.99	-0.92	2.73	1.97
Mesa Verde NP	2.86	2.47	3.14	2.76	-0.27	-0.28	2.80	2.41
Mount Baldy WA	2.37	1.94	3.24	2.69	-0.86	-0.75	2.05	1.69
Mount Zirkel WA	4.10	2.97	5.13	3.95	-1.03	-0.98	4.04	2.92
Pecos WA	2.96	2.25	3.95	2.99	-0.99	-0.74	2.17	2.07
Petrified Forest NP	2.03	1.72	2.66	2.16	-0.63	-0.44	1.98	1.67
Rawah WA	3.09	2.39	4.07	3.27	-0.98	-0.88	3.00	2.33
Rocky Mountain NP	3.22	2.44	4.49	3.50	-1.26	-1.06	3.12	2.37
Salt Creek WA	2.69	2.42	8.21	5.39	-5.52	-2.97	2.63	2.37
San Pedro Parks WA	2.68	2.31	3.36	2.93	-0.69	-0.62	2.23	2.13
Weminuche WA	3.00	2.11	3.80	2.84	-0.81	-0.73	2.86	2.03
West Elk WA	2.44	1.87	3.34	2.63	-0.90	-0.76	2.13	1.80
Wheeler Peak WA	3.06	2.52	4.11	3.44	-1.05	-0.91	2.87	2.38
White Mountain WA	3.08	2.42	3.73	2.85	-0.65	-0.43	2.56	2.14

Table 5-33c. Total annual nitrogen deposition at Class I areas for the 2021 Medium Development Scenario, 2008 Base Case, their differences (2021 Medium minus 2008) and 2021 Medium Development Scenario without the contributions of natural emissions (e.g., wildfires).

Class I Area	2021 High		2008 Base		2021 High - 2008		2021 Hi - Natural	
	N-Max	N-Avg	N-Max	N-Avg	N-Max	N-Avg	N-Max	N-Avg
	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)
Arches NP	1.67	1.55	2.20	1.81	-0.54	-0.26	1.63	1.52
Bandelier NM	8.46	2.50	9.00	2.96	-0.54	-0.46	1.81	1.72
Black Canyon NP	2.83	2.29	2.99	2.57	-0.16	-0.29	2.78	2.23
Bosque del Apache WA	2.49	1.64	5.08	2.46	-2.60	-0.83	2.26	1.51
Canyonlands NP	1.89	1.43	2.31	1.77	-0.42	-0.35	1.83	1.39
Capitol Reef NP	3.22	1.54	3.37	1.90	-0.15	-0.36	3.20	1.52
Eagles Nest WA	2.76	2.06	3.59	2.94	-0.83	-0.88	2.70	2.01
Flat Tops WA	2.95	2.35	3.71	3.09	-0.75	-0.73	2.86	2.31
Galiuro WA	2.39	2.29	2.97	2.83	-0.57	-0.54	2.38	2.28
Gila WA	2.07	1.36	2.69	1.68	-0.63	-0.31	1.98	1.31
Great Sand Dunes NM	2.76	1.96	2.70	1.95	0.06	0.01	2.66	1.89
La Garita WA	1.96	1.54	2.75	2.11	-0.79	-0.57	1.87	1.47
Maroon Bells-Snowmass	2.98	2.15	3.81	2.94	-0.84	-0.79	2.89	2.09
Mesa Verde NP	2.90	2.51	3.14	2.76	-0.23	-0.24	2.84	2.46
Mount Baldy WA	2.38	1.94	3.24	2.69	-0.86	-0.75	2.05	1.69
Mount Zirkel WA	4.27	3.10	5.13	3.95	-0.86	-0.86	4.20	3.05
Pecos WA	2.98	2.27	3.95	2.99	-0.97	-0.72	2.19	2.08
Petrified Forest NP	2.04	1.72	2.66	2.16	-0.62	-0.44	1.98	1.68
Rawah WA	3.21	2.49	4.07	3.27	-0.86	-0.78	3.12	2.43
Rocky Mountain NP	3.39	2.56	4.49	3.50	-1.10	-0.93	3.29	2.49
Salt Creek WA	2.69	2.43	8.21	5.39	-5.52	-2.97	2.64	2.38
San Pedro Parks WA	2.69	2.33	3.36	2.93	-0.67	-0.61	2.24	2.14
Weminuche WA	3.01	2.13	3.80	2.84	-0.79	-0.71	2.88	2.05
West Elk WA	2.56	1.96	3.34	2.63	-0.78	-0.67	2.25	1.89
Wheeler Peak WA	3.09	2.55	4.11	3.44	-1.03	-0.89	2.89	2.40
White Mountain WA	3.09	2.42	3.73	2.85	-0.65	-0.42	2.57	2.14

Table 5-34a. Total annual sulfur deposition at Class I areas for the 2021 High Development Scenario, 2008 Base Case, their differences (2021 High minus 2008) and 2021 High Development Scenario without the contributions of natural emissions (e.g., wildfires).

Class I Area	2021 High		2008 Base		2021 High - 2008		2021 Hi - Natural	
	S-Max	S-Avg	S-Max	S-Avg	S-Max	S-Avg	S-Max	S-Avg
	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)
Arches NP	0.22	0.20	0.36	0.33	-0.14	-0.13	0.22	0.22
Bandelier NM	0.77	0.47	1.12	0.71	-0.34	-0.24	0.61	0.77
Black Canyon NP	0.36	0.31	0.62	0.53	-0.26	-0.22	0.36	0.36
Bosque del Apache WA	0.38	0.35	0.41	0.36	-0.03	-0.02	0.38	0.38
Canyonlands NP	0.35	0.22	0.60	0.35	-0.25	-0.13	0.35	0.35
Capitol Reef NP	0.40	0.22	0.55	0.33	-0.15	-0.11	0.40	0.40
Eagles Nest WA	0.92	0.56	1.56	1.10	-0.64	-0.54	0.92	0.92
Flat Tops WA	1.04	0.71	1.72	1.33	-0.69	-0.61	1.04	1.04
Galiuro WA	1.31	1.17	1.12	1.02	0.19	0.15	1.31	1.31
Gila WA	1.32	0.58	1.61	0.72	-0.29	-0.13	1.32	1.32
Great Sand Dunes NM	0.57	0.33	0.94	0.56	-0.38	-0.23	0.57	0.57
La Garita WA	0.67	0.43	1.25	0.88	-0.58	-0.45	0.67	0.67
Maroon Bells-Snowmass	1.14	0.70	1.86	1.33	-0.71	-0.64	1.14	1.14
Mesa Verde NP	0.58	0.49	0.91	0.80	-0.33	-0.32	0.58	0.58
Mount Baldy WA	1.74	1.13	2.06	1.52	-0.33	-0.38	1.72	1.74
Mount Zirkel WA	1.48	0.93	2.34	1.73	-0.86	-0.80	1.48	1.48
Pecos WA	1.42	0.83	1.95	1.30	-0.53	-0.46	1.40	1.42
Petrified Forest NP	0.58	0.47	0.80	0.68	-0.22	-0.21	0.58	0.58
Rawah WA	1.01	0.65	1.77	1.29	-0.77	-0.64	1.00	1.01
Rocky Mountain NP	1.11	0.68	1.91	1.35	-0.80	-0.66	1.11	1.11
Salt Creek WA	0.69	0.61	0.73	0.66	-0.04	-0.05	0.69	0.69
San Pedro Parks WA	1.11	0.77	1.61	1.24	-0.51	-0.47	1.10	1.11
Weminuche WA	1.50	0.80	2.06	1.36	-0.56	-0.56	1.50	1.50
West Elk WA	0.90	0.53	1.48	1.01	-0.58	-0.48	0.89	0.90
Wheeler Peak WA	1.54	1.07	2.23	1.66	-0.69	-0.59	1.53	1.54
White Mountain WA	1.61	0.97	1.85	1.11	-0.24	-0.14	1.59	1.61

Table 5-34b. Total annual sulfur deposition at Class I areas for the 2021 Low Development Scenario, 2008 Base Case, their differences (2021 Low minus 2008) and 2021 Low Development Scenario without the contributions of natural emissions (e.g., wildfires).

Class I Area	2021 Low		2008 Base		2021 Low - 2008		2021 Low - Natural	
	S-Max	S-Avg	S-Max	S-Avg	S-Max	S-Avg	S-Max	S-Avg
	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)
Arches NP	0.22	0.20	0.36	0.33	-0.15	-0.13	0.22	0.20
Bandelier NM	0.77	0.47	1.12	0.71	-0.34	-0.24	0.61	0.45
Black Canyon NP	0.36	0.31	0.62	0.53	-0.26	-0.22	0.36	0.31
Bosque del Apache WA	0.38	0.35	0.41	0.36	-0.03	-0.02	0.38	0.35
Canyonlands NP	0.35	0.22	0.60	0.35	-0.25	-0.13	0.35	0.22
Capitol Reef NP	0.40	0.22	0.55	0.33	-0.15	-0.11	0.40	0.22
Eagles Nest WA	0.92	0.56	1.56	1.10	-0.64	-0.54	0.92	0.56
Flat Tops WA	1.03	0.71	1.72	1.33	-0.69	-0.62	1.03	0.71
Galiuro WA	1.31	1.17	1.12	1.02	0.19	0.15	1.31	1.17
Gila WA	1.32	0.58	1.61	0.72	-0.29	-0.13	1.32	0.58
Great Sand Dunes NM	0.57	0.33	0.94	0.56	-0.38	-0.23	0.57	0.33
La Garita WA	0.67	0.43	1.25	0.88	-0.58	-0.45	0.67	0.43
Maroon Bells-Snowmass	1.14	0.69	1.86	1.33	-0.72	-0.64	1.14	0.69
Mesa Verde NP	0.58	0.49	0.91	0.80	-0.33	-0.32	0.58	0.49
Mount Baldy WA	1.74	1.13	2.06	1.52	-0.33	-0.38	1.72	1.13
Mount Zirkel WA	1.47	0.93	2.34	1.73	-0.87	-0.80	1.47	0.93
Pecos WA	1.42	0.83	1.95	1.30	-0.53	-0.47	1.40	0.83
Petrified Forest NP	0.58	0.47	0.80	0.68	-0.22	-0.21	0.58	0.47
Rawah WA	1.00	0.65	1.77	1.29	-0.77	-0.64	1.00	0.65
Rocky Mountain NP	1.11	0.68	1.91	1.35	-0.80	-0.67	1.10	0.68
Salt Creek WA	0.69	0.61	0.73	0.66	-0.04	-0.05	0.69	0.61
San Pedro Parks WA	1.11	0.76	1.61	1.24	-0.51	-0.47	1.10	0.76
Weminuche WA	1.50	0.80	2.06	1.36	-0.56	-0.56	1.50	0.80
West Elk WA	0.90	0.53	1.48	1.01	-0.58	-0.48	0.89	0.53
Wheeler Peak WA	1.54	1.07	2.23	1.66	-0.69	-0.59	1.53	1.07
White Mountain WA	1.61	0.97	1.85	1.11	-0.24	-0.14	1.59	0.96

Table 5-34c. Total annual sulfur deposition at Class I areas for the 2021 Medium Development Scenario, 2008 Base Case, their differences (2021 Medium minus 2008) and 2021 Medium Development Scenario without the contributions of natural emissions (e.g., wildfires).

Class I Area	2021 High		2008 Base		2021 High - 2008		2021 Hi - Natural	
	S-Max	S-Avg	S-Max	S-Avg	S-Max	S-Avg	S-Max	S-Avg
	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)	(kg/ha)
Arches NP	0.22	0.20	0.36	0.33	-0.14	-0.13	0.22	0.20
Bandelier NM	0.77	0.47	1.12	0.71	-0.34	-0.24	0.61	0.45
Black Canyon NP	0.36	0.31	0.62	0.53	-0.26	-0.22	0.36	0.31
Bosque del Apache WA	0.38	0.35	0.41	0.36	-0.03	-0.02	0.38	0.35
Canyonlands NP	0.35	0.22	0.60	0.35	-0.25	-0.13	0.35	0.22
Capitol Reef NP	0.40	0.22	0.55	0.33	-0.15	-0.11	0.40	0.22
Eagles Nest WA	0.92	0.56	1.56	1.10	-0.64	-0.54	0.92	0.56
Flat Tops WA	1.04	0.71	1.72	1.33	-0.69	-0.61	1.04	0.71
Galiuro WA	1.31	1.17	1.12	1.02	0.19	0.15	1.31	1.17
Gila WA	1.32	0.58	1.61	0.72	-0.29	-0.13	1.32	0.58
Great Sand Dunes NM	0.57	0.33	0.94	0.56	-0.38	-0.23	0.57	0.33
La Garita WA	0.67	0.43	1.25	0.88	-0.58	-0.45	0.67	0.43
Maroon Bells-Snowmass	1.14	0.70	1.86	1.33	-0.71	-0.64	1.14	0.70
Mesa Verde NP	0.58	0.49	0.91	0.80	-0.33	-0.32	0.58	0.49
Mount Baldy WA	1.74	1.13	2.06	1.52	-0.33	-0.38	1.72	1.13
Mount Zirkel WA	1.48	0.93	2.34	1.73	-0.86	-0.80	1.48	0.93
Pecos WA	1.42	0.83	1.95	1.30	-0.53	-0.46	1.40	0.83
Petrified Forest NP	0.58	0.47	0.80	0.68	-0.22	-0.21	0.58	0.47
Rawah WA	1.01	0.65	1.77	1.29	-0.77	-0.64	1.00	0.65
Rocky Mountain NP	1.11	0.68	1.91	1.35	-0.80	-0.66	1.11	0.68
Salt Creek WA	0.69	0.61	0.73	0.66	-0.04	-0.05	0.69	0.61
San Pedro Parks WA	1.11	0.77	1.61	1.24	-0.51	-0.47	1.10	0.76
Weminuche WA	1.50	0.80	2.06	1.36	-0.56	-0.56	1.50	0.80
West Elk WA	0.90	0.53	1.48	1.01	-0.58	-0.48	0.89	0.53
Wheeler Peak WA	1.54	1.07	2.23	1.66	-0.69	-0.59	1.53	1.07
White Mountain WA	1.61	0.97	1.85	1.11	-0.24	-0.14	1.59	0.96

5.5 Acid Neutralizing Capacity (ANC) at Sensitive Lakes

Acid Neutralizing Capacity (ANC) at sensitive lakes was calculated for each Source Group following the procedures given in Section 4.8. For a Project, the USFS ANC Level of Acceptable Change (LAC) threshold is no change greater than 10% for lakes with base ANC > 25 µeq/l and no change greater than 1 µeq/l for lakes with base ANC values < 25 µeq/l. Attachments E-1, E-2 and E-3 are interactive Excel spreadsheet that displays the change in ANC at the sensitive lakes due to emissions from each of the 24 Source Groups and the, respectively, High, Low and Medium Development Scenarios. The Source Group to be displayed is controlled by cell B3 with the resultant change in ANC (Delta ANC) shown as a percent in Column N and as µeq/l in Column O with an indication of whether it is below the USFS LAC value given in Column P. Although ANC is presented for each Source Group, the ANC results for the Source Groups with existing sources (U, V, W and X) are not meaningful since their effects are contained within both the 10 percentile baseline lake acidity as well as the incremental acidity added to the baseline.

5.5.1 ANC Calculations for Individual BLM Planning Areas

For new Federal O&G from each of the 14 BLM Planning Areas (Source Groups A through P) the change in ANC were below the USFS LAC significance thresholds at all of the sensitive lakes. For example, Table 5-35 displays ANC results from Attachment E-1 (2021 High Development Scenario) for the GJFO, UFO and USFS-PG Planning Areas (Source Groups E, F and J). For new Federal O&G from the GJFO Planning Area and the 2021 High Scenario, the maximum change in ANC at any sensitive lake is 3.22% at the White Dome Lake in the Weminuche National Forest. This change is below both of the USFS LAC values (Table 5-35a). Note that Attachment D contains more information on the sensitive lakes than presented in Table 5-35 including the lake chemistry parameters. For new Federal O&G within the UFO Planning Area and the 2021 High Scenario, the maximum change in ANC at any sensitive lake is 1.02% at Deep Creek Lake in the Raggeds Wilderness Area - Gunnison National Forest that is below the USFS LAC thresholds (Table 5-35b). New Federal O&G development within the USFS Pawnee Grassland Planning Area has almost no effect on acidification at the sensitive lakes with maximum change in ANC values of 0.02% (Table 5-35c). ANC results for the other BLM Planning Areas and the 2021 Low and Medium Development Scenario are contained in Attachments E-1, E-2 and E-3.

Table 5-35a. ANC calculations at sensitive lakes for new Federal oil and gas development within the BLM Grand Junction Field Office Planning Area (Source Group E) and the 2021 High Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0003	0.0277	0.898	0.33%	0.3316	<10%	yes	101.3
Tabor Lake	112.4	0.0003	0.0289	0.860	0.32%	0.3617	<10%	yes	112.0
Booth Lake	86.8	0.0004	0.0442	0.844	0.65%	0.5621	<10%	yes	86.2
Upper Willow Lake	134.1	0.0002	0.0295	0.741	0.32%	0.4278	<10%	yes	133.7
Ned Wilson Lake	39.0	0.0004	0.0438	1.158	1.04%	0.4059	<10%	yes	38.6
Upper Ned Wilson Lake	12.9	0.0004	0.0438	1.158	3.15%	0.4059	<1(µeq/L)	yes	12.5
Lower NWL Packtrail Pothole	29.7	0.0004	0.0438	1.158	1.37%	0.4059	<10%	yes	29.2
Upper NWL Packtrail Pothole	48.7	0.0004	0.0438	1.158	0.83%	0.4059	<10%	yes	48.3
Walk Up Lake	55.2	0.0000	0.0008	0.878	0.02%	0.0101	<10%	yes	55.2
Bluebell Lake	55.5	0.0000	0.0005	0.883	0.01%	0.0066	<10%	yes	55.5
Dean Lake	48.9	0.0000	0.0005	1.061	0.01%	0.0050	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0000	0.0008	0.844	0.02%	0.0105	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0000	0.0006	0.960	0.01%	0.0070	<10%	yes	64.8
Fish Lake	105.8	0.0000	0.0008	0.869	0.01%	0.0101	<10%	yes	105.7
Blodgett Lake, Colorado	47.7	0.0004	0.0471	0.928	1.14%	0.5446	<10%	yes	47.1
Upper Turquoise Lake	104.0	0.0004	0.0475	0.809	0.61%	0.6316	<10%	yes	103.4
Upper West Tennessee Lake	114.2	0.0003	0.0374	0.904	0.39%	0.4440	<10%	yes	113.8
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0003	0.0360	1.128	1.78%	0.3424	<1(µeq/L)	yes	18.9
Crater Lake	53.1	0.0003	0.0314	1.071	0.59%	0.3144	<10%	yes	52.8
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0002	0.0331	0.959	0.71%	0.3699	<10%	yes	51.9
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0003	0.0370	1.126	1.38%	0.3531	<10%	yes	25.3
Upper Lake	69.0	0.0003	0.0340	1.139	0.46%	0.3204	<10%	yes	68.7
Small Lake Above U-Shaped Lake	59.9	0.0001	0.0100	0.927	0.19%	0.1153	<10%	yes	59.8
U-Shaped Lake	81.4	0.0001	0.0100	0.927	0.14%	0.1153	<10%	yes	81.2
Avalanche Lake	158.8	0.0006	0.0526	1.282	0.28%	0.4419	<10%	yes	158.4
Capitol Lake	154.4	0.0006	0.0519	1.110	0.33%	0.5030	<10%	yes	153.9
Moon Lake (Upper)	53.0	0.0006	0.0519	1.110	0.95%	0.5030	<10%	yes	52.5
Upper Middle Beartrack Lake	50.9	0.0002	0.0209	0.869	0.51%	0.2583	<10%	yes	50.6
Abyss Lake	81.1	0.0001	0.0218	0.896	0.32%	0.2613	<10%	yes	80.8
Frozen Lake	93.3	0.0001	0.0218	0.896	0.28%	0.2613	<10%	yes	93.0
North Lake	80.9	0.0001	0.0218	0.896	0.32%	0.2613	<10%	yes	80.7
South Lake	66.7	0.0001	0.0218	0.896	0.39%	0.2613	<10%	yes	66.5
Lake Elbert	56.6	0.0003	0.0299	1.726	0.33%	0.1859	<10%	yes	56.4
Seven Lakes (LG East)	36.2	0.0002	0.0246	1.546	0.47%	0.1713	<10%	yes	36.1
Summit Lake	48.0	0.0003	0.0290	1.449	0.45%	0.2153	<10%	yes	47.8
Deep Creek Lake	20.6	0.0003	0.0409	0.887	2.40%	0.4949	<1(µeq/L)	yes	20.1
Island Lake	71.0	0.0002	0.0222	1.079	0.31%	0.2215	<10%	yes	70.8
Kelly Lake	179.9	0.0002	0.0222	1.079	0.12%	0.2215	<10%	yes	179.6
Rawah Lake #4	41.3	0.0002	0.0225	1.098	0.53%	0.2206	<10%	yes	41.1
Crater Lake (Sangre de Cristo)	162.9	0.0001	0.0097	0.959	0.07%	0.1084	<10%	yes	162.8
Lower Stout Lake	145.2	0.0001	0.0123	0.671	0.14%	0.1975	<10%	yes	145.0
Upper Little Sand Creek Lake	129.5	0.0001	0.0092	1.064	0.07%	0.0926	<10%	yes	129.4
Upper Stout Lake	76.3	0.0001	0.0123	0.671	0.26%	0.1975	<10%	yes	76.1
Glacier Lake (Colorado)	63.4	0.0000	0.0042	1.145	0.06%	0.0398	<10%	yes	63.4
Lake South of Blue Lakes	16.9	0.0000	0.0050	1.312	0.24%	0.0406	<1(µeq/L)	yes	16.9
Big Eldorado Lake	19.6	0.0000	0.0070	1.128	0.34%	0.0664	<1(µeq/L)	yes	19.6
Four Mile Pothole	123.4	0.0001	0.0069	1.173	0.05%	0.0633	<10%	yes	123.3
Lake Due South of Ute Lake	13.2	0.0000	0.0059	1.067	0.45%	0.0597	<1(µeq/L)	yes	13.1
Little Eldorado	-3.3	0.0000	0.0070	1.128	2.01%	0.0664	<1(µeq/L)	yes	-3.4
Little Granite Lake	80.7	0.0000	0.0069	0.830	0.11%	0.0890	<10%	yes	80.6
Lower Sunlight Lake	80.9	0.0001	0.0073	1.177	0.08%	0.0670	<10%	yes	80.8
Middle Ute Lake	42.8	0.0000	0.0059	1.052	0.14%	0.0603	<10%	yes	42.7
Small Pond Above Trout Lake	25.5	0.0000	0.0069	1.087	0.27%	0.0682	<10%	yes	25.4
Upper Grizzly Lake	29.9	0.0001	0.0075	1.177	0.23%	0.0689	<10%	yes	29.8
Upper Sunlight Lake	28.0	0.0001	0.0075	1.177	0.25%	0.0689	<10%	yes	27.9
West Snowdon Lake	39.4	0.0000	0.0070	0.978	0.20%	0.0772	<10%	yes	39.3
White Dome Lake	2.1	0.0000	0.0070	1.128	3.22%	0.0664	<1(µeq/L)	yes	2.0
South Golden Lake	111.4	0.0002	0.0317	0.984	0.31%	0.3456	<10%	yes	111.1

* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

Table 5-35b. ANC calculations at sensitive lakes for new Federal oil and gas development within the BLM Uncompahgre Field Office Planning Area (Source Group F) and the 2021 High Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0001	0.0045	0.898	0.05%	0.0543	<10%	yes	101.6
Tabor Lake	112.4	0.0001	0.0044	0.860	0.05%	0.0559	<10%	yes	112.3
Booth Lake	86.8	0.0000	0.0030	0.844	0.04%	0.0389	<10%	yes	86.7
Upper Willow Lake	134.1	0.0000	0.0022	0.741	0.02%	0.0325	<10%	yes	134.1
Ned Wilson Lake	39.0	0.0000	0.0015	1.158	0.04%	0.0137	<10%	yes	39.0
Upper Ned Wilson Lake	12.9	0.0000	0.0015	1.158	0.11%	0.0137	<1(µeq/L)	yes	12.9
Lower NWL Packtrail Pothole	29.7	0.0000	0.0015	1.158	0.05%	0.0137	<10%	yes	29.6
Upper NWL Packtrail Pothole	48.7	0.0000	0.0015	1.158	0.03%	0.0137	<10%	yes	48.7
Walk Up Lake	55.2	0.0000	0.0000	0.878	0.00%	0.0003	<10%	yes	55.2
Bluebell Lake	55.5	0.0000	0.0000	0.883	0.00%	0.0002	<10%	yes	55.5
Dean Lake	48.9	0.0000	0.0000	1.061	0.00%	0.0001	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0000	0.0000	0.844	0.00%	0.0003	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0000	0.0000	0.960	0.00%	0.0002	<10%	yes	64.8
Fish Lake	105.8	0.0000	0.0000	0.869	0.00%	0.0003	<10%	yes	105.8
Blodgett Lake, Colorado	47.7	0.0001	0.0044	0.928	0.11%	0.0518	<10%	yes	47.6
Upper Turquoise Lake	104.0	0.0001	0.0038	0.809	0.05%	0.0506	<10%	yes	103.9
Upper West Tennessee Lake	114.2	0.0001	0.0041	0.904	0.04%	0.0492	<10%	yes	114.2
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0000	0.0025	1.128	0.12%	0.0235	<1(µeq/L)	yes	19.2
Crater Lake	53.1	0.0000	0.0021	1.071	0.04%	0.0211	<10%	yes	53.1
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0000	0.0021	0.959	0.05%	0.0236	<10%	yes	52.2
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0000	0.0025	1.126	0.09%	0.0240	<10%	yes	25.6
Upper Lake	69.0	0.0000	0.0024	1.139	0.03%	0.0230	<10%	yes	69.0
Small Lake Above U-Shaped Lake	59.9	0.0000	0.0013	0.927	0.03%	0.0154	<10%	yes	59.9
U-Shaped Lake	81.4	0.0000	0.0013	0.927	0.02%	0.0154	<10%	yes	81.3
Avalanche Lake	158.8	0.0004	0.0147	1.282	0.08%	0.1250	<10%	yes	158.7
Capitol Lake	154.4	0.0003	0.0132	1.110	0.08%	0.1299	<10%	yes	154.3
Moon Lake (Upper)	53.0	0.0003	0.0132	1.110	0.25%	0.1299	<10%	yes	52.9
Upper Middle Beartrack Lake	50.9	0.0000	0.0017	0.869	0.04%	0.0205	<10%	yes	50.9
Abyss Lake	81.1	0.0000	0.0018	0.896	0.03%	0.0211	<10%	yes	81.1
Frozen Lake	93.3	0.0000	0.0018	0.896	0.02%	0.0211	<10%	yes	93.2
North Lake	80.9	0.0000	0.0018	0.896	0.03%	0.0211	<10%	yes	80.9
South Lake	66.7	0.0000	0.0018	0.896	0.03%	0.0211	<10%	yes	66.7
Lake Elbert	56.6	0.0000	0.0011	1.726	0.01%	0.0066	<10%	yes	56.6
Seven Lakes (LG East)	36.2	0.0000	0.0007	1.546	0.01%	0.0052	<10%	yes	36.2
Summit Lake	48.0	0.0000	0.0011	1.449	0.02%	0.0084	<10%	yes	48.0
Deep Creek Lake	20.6	0.0003	0.0173	0.887	1.02%	0.2107	<1(µeq/L)	yes	20.4
Island Lake	71.0	0.0000	0.0014	1.079	0.02%	0.0141	<10%	yes	71.0
Kelly Lake	179.9	0.0000	0.0014	1.079	0.01%	0.0141	<10%	yes	179.8
Rawah Lake #4	41.3	0.0000	0.0014	1.098	0.03%	0.0137	<10%	yes	41.3
Crater Lake (Sangre de Cristo)	162.9	0.0000	0.0012	0.959	0.01%	0.0134	<10%	yes	162.9
Lower Stout Lake	145.2	0.0000	0.0019	0.671	0.02%	0.0308	<10%	yes	145.2
Upper Little Sand Creek Lake	129.5	0.0000	0.0012	1.064	0.01%	0.0118	<10%	yes	129.5
Upper Stout Lake	76.3	0.0000	0.0019	0.671	0.04%	0.0308	<10%	yes	76.3
Glacier Lake (Colorado)	63.4	0.0000	0.0005	1.145	0.01%	0.0044	<10%	yes	63.4
Lake South of Blue Lakes	16.9	0.0000	0.0005	1.312	0.02%	0.0042	<1(µeq/L)	yes	16.9
Big Eldorado Lake	19.6	0.0000	0.0007	1.128	0.03%	0.0065	<1(µeq/L)	yes	19.6
Four Mile Pothole	123.4	0.0000	0.0006	1.173	0.00%	0.0057	<10%	yes	123.4
Lake Due South of Ute Lake	13.2	0.0000	0.0006	1.067	0.04%	0.0057	<1(µeq/L)	yes	13.2
Little Eldorado	-3.3	0.0000	0.0007	1.128	0.20%	0.0065	<1(µeq/L)	yes	-3.3
Little Granite Lake	80.7	0.0000	0.0007	0.830	0.01%	0.0092	<10%	yes	80.7
Lower Sunlight Lake	80.9	0.0000	0.0007	1.177	0.01%	0.0063	<10%	yes	80.9
Middle Ute Lake	42.8	0.0000	0.0006	1.052	0.01%	0.0059	<10%	yes	42.8
Small Pond Above Trout Lake	25.5	0.0000	0.0007	1.087	0.03%	0.0071	<10%	yes	25.5
Upper Grizzly Lake	29.9	0.0000	0.0007	1.177	0.02%	0.0063	<10%	yes	29.9
Upper Sunlight Lake	28.0	0.0000	0.0007	1.177	0.02%	0.0063	<10%	yes	28.0
West Snowdon Lake	39.4	0.0000	0.0007	0.978	0.02%	0.0074	<10%	yes	39.3
White Dome Lake	2.1	0.0000	0.0007	1.128	0.32%	0.0065	<1(µeq/L)	yes	2.1
South Golden Lake	111.4	0.0001	0.0090	0.984	0.09%	0.0989	<10%	yes	111.3

* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

Table 5-35c. ANC calculations at sensitive lakes for new Federal oil and gas development within the USFS Pawnee Grasslands Planning Area (Source Group J) and the 2021 High Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0000	0.0000	0.898	0.00%	0.0005	<10%	yes	101.7
Tabor Lake	112.4	0.0000	0.0000	0.860	0.00%	0.0005	<10%	yes	112.4
Booth Lake	86.8	0.0000	0.0001	0.844	0.00%	0.0006	<10%	yes	86.8
Upper Willow Lake	134.1	0.0000	0.0001	0.741	0.00%	0.0015	<10%	yes	134.1
Ned Wilson Lake	39.0	0.0000	0.0000	1.158	0.00%	0.0001	<10%	yes	39.0
Upper Ned Wilson Lake	12.9	0.0000	0.0000	1.158	0.00%	0.0001	<1(µeq/L)	yes	12.9
Lower NWL Packtrail Pothole	29.7	0.0000	0.0000	1.158	0.00%	0.0001	<10%	yes	29.6
Upper NWL Packtrail Pothole	48.7	0.0000	0.0000	1.158	0.00%	0.0001	<10%	yes	48.7
Walk Up Lake	55.2	0.0000	0.0000	0.878	0.00%	0.0000	<10%	yes	55.2
Bluebell Lake	55.5	0.0000	0.0000	0.883	0.00%	0.0000	<10%	yes	55.5
Dean Lake	48.9	0.0000	0.0000	1.061	0.00%	0.0000	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0000	0.0000	0.844	0.00%	0.0000	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0000	0.0000	0.960	0.00%	0.0000	<10%	yes	64.8
Fish Lake	105.8	0.0000	0.0000	0.869	0.00%	0.0000	<10%	yes	105.8
Blodgett Lake, Colorado	47.7	0.0000	0.0000	0.928	0.00%	0.0003	<10%	yes	47.7
Upper Turquoise Lake	104.0	0.0000	0.0000	0.809	0.00%	0.0005	<10%	yes	104.0
Upper West Tennessee Lake	114.2	0.0000	0.0000	0.904	0.00%	0.0006	<10%	yes	114.2
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0000	0.0003	1.128	0.02%	0.0032	<1(µeq/L)	yes	19.2
Crater Lake	53.1	0.0000	0.0003	1.071	0.01%	0.0027	<10%	yes	53.1
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0000	0.0004	0.959	0.01%	0.0042	<10%	yes	52.3
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0000	0.0005	1.126	0.02%	0.0044	<10%	yes	25.6
Upper Lake	69.0	0.0000	0.0003	1.139	0.00%	0.0024	<10%	yes	69.0
Small Lake Above U-Shaped Lake	59.9	0.0000	0.0000	0.927	0.00%	0.0004	<10%	yes	59.9
U-Shaped Lake	81.4	0.0000	0.0000	0.927	0.00%	0.0004	<10%	yes	81.4
Avalanche Lake	158.8	0.0000	0.0000	1.282	0.00%	0.0001	<10%	yes	158.8
Capitol Lake	154.4	0.0000	0.0000	1.110	0.00%	0.0002	<10%	yes	154.4
Moon Lake (Upper)	53.0	0.0000	0.0000	1.110	0.00%	0.0002	<10%	yes	53.0
Upper Middle Beartrack Lake	50.9	0.0000	0.0005	0.869	0.01%	0.0064	<10%	yes	50.9
Abyss Lake	81.1	0.0000	0.0004	0.896	0.01%	0.0044	<10%	yes	81.1
Frozen Lake	93.3	0.0000	0.0004	0.896	0.00%	0.0044	<10%	yes	93.3
North Lake	80.9	0.0000	0.0004	0.896	0.01%	0.0044	<10%	yes	80.9
South Lake	66.7	0.0000	0.0004	0.896	0.01%	0.0044	<10%	yes	66.7
Lake Elbert	56.6	0.0000	0.0000	1.726	0.00%	0.0002	<10%	yes	56.6
Seven Lakes (LG East)	36.2	0.0000	0.0000	1.546	0.00%	0.0002	<10%	yes	36.2
Summit Lake	48.0	0.0000	0.0000	1.449	0.00%	0.0002	<10%	yes	48.0
Deep Creek Lake	20.6	0.0000	0.0000	0.887	0.00%	0.0002	<1(µeq/L)	yes	20.6
Island Lake	71.0	0.0000	0.0001	1.079	0.00%	0.0012	<10%	yes	71.0
Kelly Lake	179.9	0.0000	0.0001	1.079	0.00%	0.0012	<10%	yes	179.8
Rawah Lake #4	41.3	0.0000	0.0002	1.098	0.00%	0.0015	<10%	yes	41.3
Crater Lake (Sangre de Cristo)	162.9	0.0000	0.0002	0.959	0.00%	0.0024	<10%	yes	162.9
Lower Stout Lake	145.2	0.0000	0.0003	0.671	0.00%	0.0042	<10%	yes	145.2
Upper Little Sand Creek Lake	129.5	0.0000	0.0002	1.064	0.00%	0.0025	<10%	yes	129.5
Upper Stout Lake	76.3	0.0000	0.0003	0.671	0.01%	0.0042	<10%	yes	76.3
Glacier Lake (Colorado)	63.4	0.0000	0.0001	1.145	0.00%	0.0005	<10%	yes	63.4
Lake South of Blue Lakes	16.9	0.0000	0.0001	1.312	0.00%	0.0005	<1(µeq/L)	yes	16.9
Big Eldorado Lake	19.6	0.0000	0.0000	1.128	0.00%	0.0001	<1(µeq/L)	yes	19.6
Four Mile Pothole	123.4	0.0000	0.0000	1.173	0.00%	0.0003	<10%	yes	123.4
Lake Due South of Ute Lake	13.2	0.0000	0.0000	1.067	0.00%	0.0001	<1(µeq/L)	yes	13.2
Little Eldorado	-3.3	0.0000	0.0000	1.128	0.00%	0.0001	<1(µeq/L)	yes	-3.3
Little Granite Lake	80.7	0.0000	0.0000	0.830	0.00%	0.0003	<10%	yes	80.7
Lower Sunlight Lake	80.9	0.0000	0.0000	1.177	0.00%	0.0001	<10%	yes	80.9
Middle Ute Lake	42.8	0.0000	0.0000	1.052	0.00%	0.0001	<10%	yes	42.8
Small Pond Above Trout Lake	25.5	0.0000	0.0000	1.087	0.00%	0.0003	<10%	yes	25.5
Upper Grizzly Lake	29.9	0.0000	0.0000	1.177	0.00%	0.0001	<10%	yes	29.9
Upper Sunlight Lake	28.0	0.0000	0.0000	1.177	0.00%	0.0001	<10%	yes	28.0
West Snowdon Lake	39.4	0.0000	0.0000	0.978	0.00%	0.0001	<10%	yes	39.3
White Dome Lake	2.1	0.0000	0.0000	1.128	0.01%	0.0001	<1(µeq/L)	yes	2.1
South Golden Lake	111.4	0.0000	0.0000	0.984	0.00%	0.0002	<10%	yes	111.4

* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

5.5.2 ANC Calculations for Combined BLM Planning Areas

The Attachment E-1, E-2 and E-3 spreadsheets also contain ANC calculations for the combined BLM Planning Area Source Groups Q through T of new emission sources. Below we provide results for Source Group R (new Federal O&G and mining within 13 CO BLM Planning Areas) and the Cumulative Emissions Scenario (Source Group T) that also adds new O&G and O&G emissions from the Mancos Shale development in northern New Mexico.

Table 5-36 displays the ANC results at the 58 sensitive lakes for the combined new Federal O&G and mining within the 13 Colorado BLM Planning Areas (Source Group R) and the 2021 High, Low and Medium Development Scenarios. For the lakes that have base ANC values $> 25 \mu\text{eq/l}$ the maximum percent change in ANC is always below the USFS LAC 10% threshold for all three 2021 emission scenarios. However, for the 8 lakes with base ANC $< 25 \mu\text{eq/l}$, three have changes in ANC greater than the $1 \mu\text{eq/l}$ USFS LAC threshold for the 2021 High Development Scenario (Table 5-36a): Upper Ned Wilson Lake ($1.61 \mu\text{eq/l}$); Blue Lake ($1.11 \mu\text{eq/l}$) and Deep Creek Lake ($1.47 \mu\text{eq/l}$). The mitigation in the 2021 Medium Development scenario is sufficient to reduce the change in ANC value at Blue Lake ($0.94 \mu\text{eq/l}$) to below the $1 \mu\text{eq/l}$ LAC threshold, but the change in ANC values at Upper Ned Wilson ($1.36 \mu\text{eq/l}$) and Deep Creek ($1.21 \mu\text{eq/l}$) lakes remain above the LAC threshold. For these same three lakes the change in ANC values are below the $1 \mu\text{eq/l}$ USFS LAC threshold for the 2021 Low Development Scenario (0.3887 , 0.2611 and $0.3577 \mu\text{eq/l}$).

The ANC results for the Cumulative Emissions Scenario (Source Group T) and the 2021 High and Low Emissions Scenario are shown in Table 5-37. Since this Source Group contains Source Group R then the same three sensitive lakes with ANC $< 25 \mu\text{eq/l}$ have changes in ANC greater than the $1 \mu\text{eq/l}$ USFS LAC threshold for the 2021 High Development Scenario (Table 5-37a): Upper Ned Wilson Lake ($2.7137 \mu\text{eq/l}$); Blue Lake ($2.4663 \mu\text{eq/l}$) and Deep Creek Lake ($2.6909 \mu\text{eq/l}$). However, in addition there is one sensitive lake with base ANC $> 25 \mu\text{eq/l}$ whose change in ANC exceeds the USFS 10% LAC threshold for the 2021 High Development Scenario and Source Group T: No Name Lake (10.50%). The mitigation in the 2021 Medium Development Scenario is sufficient to reduce the change in ANC at No Name Lake (9.67%) to below the 10% LAC threshold but not to reduce it at the other three lakes with base ANC $< 25 \mu\text{eq/l}$ to below the $1 \mu\text{eq/l}$ LAC threshold (Table 5-37c). For the 2021 Low Development Scenario and Source Group T, all sensitive lakes have change in ANC below the LAC thresholds (Table 5-37b).

Note that the USFS ANC LAC thresholds were developed for evaluating potential lake acidification for individual Projects, not for quasi-cumulative emission source groups of new O&G development across an entire state as in Source Groups R and T. In addition, the USFS ANC LAC thresholds were developed for evaluating potential lake acidification for individual Projects (i.e. new emissions since baseline lake chemistry data was monitored), not for cumulative emissions scenarios that include all existing O&G since the baseline ANC values that are used in the ANC calculations would already account for impacts from existing emissions sources.

Table 5-36a. ANC calculations at sensitive lakes for new Federal oil and gas development and mining within the 13 Colorado BLM Planning Areas (Source Group R) and 2021 High Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0061	0.0783	0.898	0.98%	0.9924	<10%	yes	100.7
Tabor Lake	112.4	0.0060	0.0808	0.860	0.95%	1.0663	<10%	yes	111.3
Booth Lake	86.8	0.0076	0.1114	0.844	1.72%	1.4898	<10%	yes	85.3
Upper Willow Lake	134.1	0.0062	0.0783	0.741	0.90%	1.2051	<10%	yes	132.9
Ned Wilson Lake	39.0	0.0195	0.1577	1.158	4.13%	1.6089	<10%	yes	37.4
Upper Ned Wilson Lake	12.9	0.0195	0.1577	1.158	12.49%	1.6089	<1(µeq/L)	no	11.3
Lower NWL Packtrail Pothole	29.7	0.0195	0.1577	1.158	5.43%	1.6089	<10%	yes	28.0
Upper NWL Packtrail Pothole	48.7	0.0195	0.1577	1.158	3.30%	1.6089	<10%	yes	47.1
Walk Up Lake	55.2	0.0003	0.0035	0.878	0.08%	0.0453	<10%	yes	55.2
Bluebell Lake	55.5	0.0001	0.0020	0.883	0.05%	0.0259	<10%	yes	55.5
Dean Lake	48.9	0.0001	0.0018	1.061	0.04%	0.0188	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0003	0.0043	0.844	0.09%	0.0580	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0002	0.0024	0.960	0.04%	0.0284	<10%	yes	64.8
Fish Lake	105.8	0.0003	0.0034	0.869	0.04%	0.0443	<10%	yes	105.7
Blodgett Lake, Colorado	47.7	0.0081	0.1146	0.928	2.93%	1.3978	<10%	yes	46.3
Upper Turquoise Lake	104.0	0.0094	0.1221	0.809	1.65%	1.7194	<10%	yes	102.3
Upper West Tennessee Lake	114.2	0.0059	0.0912	0.904	0.99%	1.1363	<10%	yes	113.1
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0115	0.1069	1.128	5.75%	1.1064	<1(µeq/L)	no	18.1
Crater Lake	53.1	0.0122	0.0963	1.071	2.01%	1.0659	<10%	yes	52.1
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0120	0.1027	0.959	2.41%	1.2580	<10%	yes	51.0
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0124	0.1104	1.126	4.48%	1.1479	<10%	yes	24.5
Upper Lake	69.0	0.0128	0.1031	1.139	1.55%	1.0700	<10%	yes	67.9
Small Lake Above U-Shaped Lake	59.9	0.0018	0.0295	0.927	0.60%	0.3574	<10%	yes	59.5
U-Shaped Lake	81.4	0.0018	0.0295	0.927	0.44%	0.3574	<10%	yes	81.0
Avalanche Lake	158.8	0.0117	0.1349	1.282	0.76%	1.2069	<10%	yes	157.6
Capitol Lake	154.4	0.0116	0.1325	1.110	0.89%	1.3695	<10%	yes	153.0
Moon Lake (Upper)	53.0	0.0116	0.1325	1.110	2.58%	1.3695	<10%	yes	51.6
Upper Middle Beartrack Lake	50.9	0.0053	0.0593	0.869	1.54%	0.7841	<10%	yes	50.1
Abyss Lake	81.1	0.0050	0.0611	0.896	0.96%	0.7790	<10%	yes	80.3
Frozen Lake	93.3	0.0050	0.0611	0.896	0.84%	0.7790	<10%	yes	92.5
North Lake	80.9	0.0050	0.0611	0.896	0.96%	0.7790	<10%	yes	80.2
South Lake	66.7	0.0050	0.0611	0.896	1.17%	0.7790	<10%	yes	66.0
Lake Elbert	56.6	0.0290	0.1501	1.726	1.92%	1.0843	<10%	yes	55.5
Seven Lakes (LG East)	36.2	0.0205	0.1239	1.546	2.70%	0.9779	<10%	yes	35.3
Summit Lake	48.0	0.0323	0.1501	1.449	2.73%	1.3118	<10%	yes	46.7
Deep Creek Lake	20.6	0.0096	0.1135	0.887	7.11%	1.4652	<1(µeq/L)	no	19.1
Island Lake	71.0	0.0140	0.0931	1.079	1.47%	1.0406	<10%	yes	70.0
Kelly Lake	179.9	0.0140	0.0931	1.079	0.58%	1.0406	<10%	yes	178.8
Rawah Lake #4	41.3	0.0135	0.0951	1.098	2.51%	1.0384	<10%	yes	40.3
Crater Lake (Sangre de Cristo)	162.9	0.0025	0.0311	0.959	0.23%	0.3696	<10%	yes	162.6
Lower Stout Lake	145.2	0.0029	0.0388	0.671	0.45%	0.6568	<10%	yes	144.5
Upper Little Sand Creek Lake	129.5	0.0027	0.0311	1.064	0.26%	0.3347	<10%	yes	129.2
Upper Stout Lake	76.3	0.0029	0.0388	0.671	0.86%	0.6568	<10%	yes	75.7
Glacier Lake (Colorado)	63.4	0.0013	0.0186	1.145	0.29%	0.1835	<10%	yes	63.2
Lake South of Blue Lakes	16.9	0.0013	0.0236	1.312	1.19%	0.2011	<1(µeq/L)	yes	16.7
Big Eldorado Lake	19.6	0.0014	0.0246	1.128	1.24%	0.2442	<1(µeq/L)	yes	19.4
Four Mile Pothole	123.4	0.0015	0.0232	1.173	0.18%	0.2229	<10%	yes	123.2
Lake Due South of Ute Lake	13.2	0.0012	0.0206	1.067	1.65%	0.2170	<1(µeq/L)	yes	12.9
Little Eldorado	-3.3	0.0014	0.0246	1.128	7.40%	0.2442	<1(µeq/L)	yes	-3.5
Little Granite Lake	80.7	0.0011	0.0229	0.830	0.38%	0.3068	<10%	yes	80.4
Lower Sunlight Lake	80.9	0.0018	0.0267	1.177	0.32%	0.2561	<10%	yes	80.6
Middle Ute Lake	42.8	0.0012	0.0206	1.052	0.51%	0.2192	<10%	yes	42.6
Small Pond Above Trout Lake	25.5	0.0012	0.0231	1.087	0.93%	0.2369	<10%	yes	25.2
Upper Grizzly Lake	29.9	0.0020	0.0272	1.177	0.88%	0.2623	<10%	yes	29.6
Upper Sunlight Lake	28.0	0.0020	0.0272	1.177	0.94%	0.2623	<10%	yes	27.7
West Snowdon Lake	39.4	0.0010	0.0246	0.978	0.71%	0.2781	<10%	yes	39.1
White Dome Lake	2.1	0.0014	0.0246	1.128	11.85%	0.2442	<1(µeq/L)	yes	1.8
South Golden Lake	111.4	0.0045	0.0872	0.984	0.89%	0.9872	<10%	yes	110.4

^{*} USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

Table 5-36b. ANC calculations at sensitive lakes for new Federal oil and gas development and mining within the 13 Colorado BLM Planning Areas (Source Group R) and 2021 Low Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0033	0.0157	0.898	0.22%	0.2204	<10%	yes	101.5
Tabor Lake	112.4	0.0033	0.0161	0.860	0.21%	0.2353	<10%	yes	112.2
Booth Lake	86.8	0.0043	0.0223	0.844	0.38%	0.3290	<10%	yes	86.5
Upper Willow Lake	134.1	0.0037	0.0157	0.741	0.20%	0.2731	<10%	yes	133.8
Ned Wilson Lake	39.0	0.0113	0.0323	1.158	1.00%	0.3887	<10%	yes	38.6
Upper Ned Wilson Lake	12.9	0.0113	0.0323	1.158	3.02%	0.3887	<1(µeq/L)	yes	12.5
Lower NWL Packtrail Pothole	29.7	0.0113	0.0323	1.158	1.31%	0.3887	<10%	yes	29.3
Upper NWL Packtrail Pothole	48.7	0.0113	0.0323	1.158	0.80%	0.3887	<10%	yes	48.3
Walk Up Lake	55.2	0.0001	0.0007	0.878	0.02%	0.0091	<10%	yes	55.2
Bluebell Lake	55.5	0.0000	0.0004	0.883	0.01%	0.0052	<10%	yes	55.5
Dean Lake	48.9	0.0000	0.0003	1.061	0.01%	0.0037	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0001	0.0008	0.844	0.02%	0.0113	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0001	0.0005	0.960	0.01%	0.0058	<10%	yes	64.8
Fish Lake	105.8	0.0001	0.0006	0.869	0.01%	0.0090	<10%	yes	105.8
Blodgett Lake, Colorado	47.7	0.0045	0.0223	0.928	0.63%	0.3009	<10%	yes	47.4
Upper Turquoise Lake	104.0	0.0053	0.0244	0.809	0.37%	0.3831	<10%	yes	103.6
Upper West Tennessee Lake	114.2	0.0033	0.0175	0.904	0.21%	0.2404	<10%	yes	114.0
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0078	0.0208	1.128	1.36%	0.2611	<1(µeq/L)	yes	19.0
Crater Lake	53.1	0.0086	0.0188	1.071	0.49%	0.2626	<10%	yes	52.9
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0084	0.0202	0.959	0.59%	0.3066	<10%	yes	52.0
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0085	0.0216	1.126	1.07%	0.2746	<10%	yes	25.3
Upper Lake	69.0	0.0084	0.0200	1.139	0.37%	0.2562	<10%	yes	68.7
Small Lake Above U-Shaped Lake	59.9	0.0009	0.0056	0.927	0.12%	0.0743	<10%	yes	59.8
U-Shaped Lake	81.4	0.0009	0.0056	0.927	0.09%	0.0743	<10%	yes	81.3
Avalanche Lake	158.8	0.0074	0.0262	1.282	0.17%	0.2716	<10%	yes	158.5
Capitol Lake	154.4	0.0071	0.0258	1.110	0.20%	0.3079	<10%	yes	154.1
Moon Lake (Upper)	53.0	0.0071	0.0258	1.110	0.58%	0.3079	<10%	yes	52.7
Upper Middle Beartrack Lake	50.9	0.0031	0.0118	0.869	0.35%	0.1779	<10%	yes	50.7
Abyss Lake	81.1	0.0029	0.0121	0.896	0.22%	0.1744	<10%	yes	80.9
Frozen Lake	93.3	0.0029	0.0121	0.896	0.19%	0.1744	<10%	yes	93.1
North Lake	80.9	0.0029	0.0121	0.896	0.22%	0.1744	<10%	yes	80.8
South Lake	66.7	0.0029	0.0121	0.896	0.26%	0.1744	<10%	yes	66.6
Lake Elbert	56.6	0.0212	0.0320	1.726	0.55%	0.3124	<10%	yes	56.3
Seven Lakes (LG East)	36.2	0.0135	0.0250	1.546	0.70%	0.2535	<10%	yes	36.0
Summit Lake	48.0	0.0250	0.0329	1.449	0.84%	0.4029	<10%	yes	47.6
Deep Creek Lake	20.6	0.0066	0.0240	0.887	1.74%	0.3577	<1(µeq/L)	yes	20.2
Island Lake	71.0	0.0094	0.0191	1.079	0.38%	0.2698	<10%	yes	70.8
Kelly Lake	179.9	0.0094	0.0191	1.079	0.15%	0.2698	<10%	yes	179.6
Rawah Lake #4	41.3	0.0090	0.0194	1.098	0.64%	0.2653	<10%	yes	41.0
Crater Lake (Sangre de Cristo)	162.9	0.0013	0.0063	0.959	0.05%	0.0825	<10%	yes	162.8
Lower Stout Lake	145.2	0.0015	0.0077	0.671	0.10%	0.1427	<10%	yes	145.1
Upper Little Sand Creek Lake	129.5	0.0014	0.0067	1.064	0.06%	0.0794	<10%	yes	129.4
Upper Stout Lake	76.3	0.0015	0.0077	0.671	0.19%	0.1427	<10%	yes	76.2
Glacier Lake (Colorado)	63.4	0.0006	0.0034	1.145	0.06%	0.0368	<10%	yes	63.4
Lake South of Blue Lakes	16.9	0.0006	0.0041	1.312	0.22%	0.0379	<1(µeq/L)	yes	16.9
Big Eldorado Lake	19.6	0.0006	0.0045	1.128	0.24%	0.0479	<1(µeq/L)	yes	19.6
Four Mile Pothole	123.4	0.0007	0.0043	1.173	0.04%	0.0446	<10%	yes	123.3
Lake Due South of Ute Lake	13.2	0.0006	0.0039	1.067	0.33%	0.0435	<1(µeq/L)	yes	13.1
Little Eldorado	-3.3	0.0006	0.0045	1.128	1.45%	0.0479	<1(µeq/L)	yes	-3.3
Little Granite Lake	80.7	0.0005	0.0043	0.830	0.07%	0.0601	<10%	yes	80.7
Lower Sunlight Lake	80.9	0.0008	0.0049	1.177	0.06%	0.0510	<10%	yes	80.8
Middle Ute Lake	42.8	0.0005	0.0038	1.052	0.10%	0.0435	<10%	yes	42.7
Small Pond Above Trout Lake	25.5	0.0006	0.0043	1.087	0.18%	0.0469	<10%	yes	25.4
Upper Grizzly Lake	29.9	0.0010	0.0050	1.177	0.18%	0.0533	<10%	yes	29.8
Upper Sunlight Lake	28.0	0.0010	0.0050	1.177	0.19%	0.0533	<10%	yes	27.9
West Snowdon Lake	39.4	0.0004	0.0044	0.978	0.13%	0.0519	<10%	yes	39.3
White Dome Lake	2.1	0.0006	0.0045	1.128	2.33%	0.0479	<1(µeq/L)	yes	2.0
South Golden Lake	111.4	0.0028	0.0170	0.984	0.19%	0.2100	<10%	yes	111.2

* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

Table 5-36c. ANC calculations at sensitive lakes for new Federal oil and gas development and mining within the 13 Colorado BLM Planning Areas (Source Group R) and 2021 Medium Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Med Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0060	0.0641	0.898	0.81%	0.8229	<10%	yes	100.9
Tabor Lake	112.4	0.0059	0.0661	0.860	0.79%	0.8827	<10%	yes	111.5
Booth Lake	86.8	0.0074	0.0913	0.844	1.42%	1.2346	<10%	yes	85.5
Upper Willow Lake	134.1	0.0061	0.0645	0.741	0.75%	1.0042	<10%	yes	133.1
Ned Wilson Lake	39.0	0.0193	0.1306	1.158	3.48%	1.3575	<10%	yes	37.6
Upper Ned Wilson Lake	12.9	0.0193	0.1306	1.158	10.54%	1.3575	<1(µeq/L)	no	11.5
Lower NWL Packtrail Pothole	29.7	0.0193	0.1306	1.158	4.58%	1.3575	<10%	yes	28.3
Upper NWL Packtrail Pothole	48.7	0.0193	0.1306	1.158	2.79%	1.3575	<10%	yes	47.3
Walk Up Lake	55.2	0.0003	0.0032	0.878	0.08%	0.0420	<10%	yes	55.2
Bluebell Lake	55.5	0.0001	0.0019	0.883	0.04%	0.0239	<10%	yes	55.5
Dean Lake	48.9	0.0001	0.0016	1.061	0.04%	0.0173	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0003	0.0040	0.844	0.08%	0.0543	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0002	0.0022	0.960	0.04%	0.0263	<10%	yes	64.8
Fish Lake	105.8	0.0002	0.0031	0.869	0.04%	0.0411	<10%	yes	105.7
Blodgett Lake, Colorado	47.7	0.0079	0.0939	0.928	2.43%	1.1578	<10%	yes	46.5
Upper Turquoise Lake	104.0	0.0092	0.1000	0.809	1.37%	1.4249	<10%	yes	102.6
Upper West Tennessee Lake	114.2	0.0057	0.0746	0.904	0.82%	0.9392	<10%	yes	113.3
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0114	0.0898	1.128	4.90%	0.9429	<1(µeq/L)	yes	18.3
Crater Lake	53.1	0.0121	0.0811	1.071	1.72%	0.9128	<10%	yes	52.2
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0118	0.0865	0.959	2.06%	1.0769	<10%	yes	51.2
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0123	0.0928	1.126	3.83%	0.9801	<10%	yes	24.6
Upper Lake	69.0	0.0126	0.0869	1.139	1.33%	0.9175	<10%	yes	68.1
Small Lake Above U-Shaped Lake	59.9	0.0017	0.0250	0.927	0.51%	0.3049	<10%	yes	59.6
U-Shaped Lake	81.4	0.0017	0.0250	0.927	0.37%	0.3049	<10%	yes	81.1
Avalanche Lake	158.8	0.0114	0.1105	1.282	0.63%	1.0020	<10%	yes	157.8
Capitol Lake	154.4	0.0113	0.1087	1.110	0.74%	1.1389	<10%	yes	153.3
Moon Lake (Upper)	53.0	0.0113	0.1087	1.110	2.15%	1.1389	<10%	yes	51.8
Upper Middle Beartrack Lake	50.9	0.0052	0.0492	0.869	1.30%	0.6592	<10%	yes	50.2
Abyss Lake	81.1	0.0049	0.0507	0.896	0.81%	0.6542	<10%	yes	80.4
Frozen Lake	93.3	0.0049	0.0507	0.896	0.70%	0.6542	<10%	yes	92.6
North Lake	80.9	0.0049	0.0507	0.896	0.81%	0.6542	<10%	yes	80.3
South Lake	66.7	0.0049	0.0507	0.896	0.98%	0.6542	<10%	yes	66.1
Lake Elbert	56.6	0.0288	0.1301	1.726	1.70%	0.9594	<10%	yes	55.6
Seven Lakes (LG East)	36.2	0.0203	0.1071	1.546	2.38%	0.8618	<10%	yes	35.4
Summit Lake	48.0	0.0321	0.1301	1.449	2.42%	1.1640	<10%	yes	46.8
Deep Creek Lake	20.6	0.0094	0.0927	0.887	5.89%	1.2130	<1(µeq/L)	no	19.4
Island Lake	71.0	0.0138	0.0792	1.079	1.27%	0.9025	<10%	yes	70.1
Kelly Lake	179.9	0.0138	0.0792	1.079	0.50%	0.9025	<10%	yes	178.9
Rawah Lake #4	41.3	0.0134	0.0808	1.098	2.18%	0.8984	<10%	yes	40.4
Crater Lake (Sangre de Cristo)	162.9	0.0024	0.0258	0.959	0.19%	0.3108	<10%	yes	162.6
Lower Stout Lake	145.2	0.0028	0.0324	0.671	0.38%	0.5539	<10%	yes	144.6
Upper Little Sand Creek Lake	129.5	0.0026	0.0258	1.064	0.22%	0.2813	<10%	yes	129.2
Upper Stout Lake	76.3	0.0028	0.0324	0.671	0.73%	0.5539	<10%	yes	75.8
Glacier Lake (Colorado)	63.4	0.0013	0.0158	1.145	0.25%	0.1572	<10%	yes	63.2
Lake South of Blue Lakes	16.9	0.0013	0.0200	1.312	1.02%	0.1717	<1(µeq/L)	yes	16.7
Big Eldorado Lake	19.6	0.0014	0.0211	1.128	1.08%	0.2113	<1(µeq/L)	yes	19.4
Four Mile Pothole	123.4	0.0015	0.0198	1.173	0.16%	0.1916	<10%	yes	123.2
Lake Due South of Ute Lake	13.2	0.0012	0.0178	1.067	1.43%	0.1881	<1(µeq/L)	yes	13.0
Little Eldorado	-3.3	0.0014	0.0211	1.128	6.40%	0.2113	<1(µeq/L)	yes	-3.5
Little Granite Lake	80.7	0.0011	0.0196	0.830	0.33%	0.2645	<10%	yes	80.5
Lower Sunlight Lake	80.9	0.0018	0.0230	1.177	0.27%	0.2220	<10%	yes	80.6
Middle Ute Lake	42.8	0.0012	0.0177	1.052	0.44%	0.1900	<10%	yes	42.6
Small Pond Above Trout Lake	25.5	0.0012	0.0197	1.087	0.80%	0.2038	<10%	yes	25.3
Upper Grizzly Lake	29.9	0.0020	0.0234	1.177	0.76%	0.2277	<10%	yes	29.7
Upper Sunlight Lake	28.0	0.0020	0.0234	1.177	0.81%	0.2277	<10%	yes	27.8
West Snowdon Lake	39.4	0.0010	0.0212	0.978	0.61%	0.2404	<10%	yes	39.1
White Dome Lake	2.1	0.0014	0.0211	1.128	10.26%	0.2113	<1(µeq/L)	yes	1.8
South Golden Lake	111.4	0.0044	0.0719	0.984	0.74%	0.8204	<10%	yes	110.6

Table 5-37a. ANC calculations at sensitive lakes for new Federal oil and gas development and mining and new non-Federal oil and gas within the 14 Colorado and northern New Mexico BLM Planning Areas (Source Group T) and the 2021 High Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0073	0.1527	0.898	1.86%	1.8877	<10%	yes	99.8
Tabor Lake	112.4	0.0071	0.1557	0.860	1.79%	2.0080	<10%	yes	110.4
Booth Lake	86.8	0.0090	0.2179	0.844	3.29%	2.8510	<10%	yes	83.9
Upper Willow Lake	134.1	0.0072	0.1589	0.741	1.77%	2.3766	<10%	yes	131.7
Ned Wilson Lake	39.0	0.0220	0.2756	1.158	6.96%	2.7137	<10%	yes	36.3
Upper Ned Wilson Lake	12.9	0.0220	0.2756	1.158	21.07%	2.7137	<1(µeq/L)	no	10.2
Lower NWL Packtrail Pothole	29.7	0.0220	0.2756	1.158	9.15%	2.7137	<10%	yes	26.9
Upper NWL Packtrail Pothole	48.7	0.0220	0.2756	1.158	5.57%	2.7137	<10%	yes	46.0
Walk Up Lake	55.2	0.0003	0.0061	0.878	0.14%	0.0780	<10%	yes	55.1
Bluebell Lake	55.5	0.0002	0.0039	0.883	0.09%	0.0484	<10%	yes	55.5
Dean Lake	48.9	0.0001	0.0034	1.061	0.07%	0.0347	<10%	yes	48.8
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0004	0.0075	0.844	0.15%	0.0989	<10%	yes	66.9
Upper Coffin Lake	64.9	0.0002	0.0044	0.960	0.08%	0.0503	<10%	yes	64.8
Fish Lake	105.8	0.0003	0.0059	0.869	0.07%	0.0758	<10%	yes	105.7
Blodgett Lake, Colorado	47.7	0.0097	0.2231	0.928	5.58%	2.6596	<10%	yes	45.0
Upper Turquoise Lake	104.0	0.0112	0.2361	0.809	3.12%	3.2422	<10%	yes	100.8
Upper West Tennessee Lake	114.2	0.0070	0.1798	0.904	1.92%	2.1922	<10%	yes	112.0
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0134	0.2491	1.128	12.81%	2.4663	<1(µeq/L)	no	16.8
Crater Lake	53.1	0.0139	0.2157	1.071	4.27%	2.2690	<10%	yes	50.9
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0136	0.2374	0.959	5.31%	2.7724	<10%	yes	49.5
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0148	0.2713	1.126	10.50%	2.6909	<10%	no	22.9
Upper Lake	69.0	0.0147	0.2274	1.139	3.26%	2.2504	<10%	yes	66.7
Small Lake Above U-Shaped Lake	59.9	0.0023	0.0717	0.927	1.41%	0.8472	<10%	yes	59.1
U-Shaped Lake	81.4	0.0023	0.0717	0.927	1.04%	0.8472	<10%	yes	80.5
Avalanche Lake	158.8	0.0138	0.2629	1.282	1.44%	2.2877	<10%	yes	156.5
Capitol Lake	154.4	0.0139	0.2581	1.110	1.68%	2.5949	<10%	yes	151.8
Moon Lake (Upper)	53.0	0.0139	0.2581	1.110	4.90%	2.5949	<10%	yes	50.4
Upper Middle Beartrack Lake	50.9	0.0070	0.1670	0.869	4.17%	2.1247	<10%	yes	48.8
Abyss Lake	81.1	0.0063	0.1566	0.896	2.38%	1.9289	<10%	yes	79.2
Frozen Lake	93.3	0.0063	0.1566	0.896	2.07%	1.9289	<10%	yes	91.3
North Lake	80.9	0.0063	0.1566	0.896	2.38%	1.9289	<10%	yes	79.0
South Lake	66.7	0.0063	0.1566	0.896	2.89%	1.9289	<10%	yes	64.8
Lake Elbert	56.6	0.0314	0.2514	1.726	3.04%	1.7227	<10%	yes	54.9
Seven Lakes (LG East)	36.2	0.0224	0.2067	1.546	4.31%	1.5610	<10%	yes	34.7
Summit Lake	48.0	0.0345	0.2513	1.449	4.31%	2.0711	<10%	yes	45.9
Deep Creek Lake	20.6	0.0111	0.2214	0.887	13.48%	2.7769	<1(µeq/L)	no	17.8
Island Lake	71.0	0.0155	0.1711	1.079	2.57%	1.8257	<10%	yes	69.2
Kelly Lake	179.9	0.0155	0.1711	1.079	1.02%	1.8257	<10%	yes	178.0
Rawah Lake #4	41.3	0.0151	0.1772	1.098	4.48%	1.8487	<10%	yes	39.4
Crater Lake (Sangre de Cristo)	162.9	0.0034	0.0932	0.959	0.66%	1.0691	<10%	yes	161.9
Lower Stout Lake	145.2	0.0038	0.1045	0.671	1.18%	1.7122	<10%	yes	143.5
Upper Little Sand Creek Lake	129.5	0.0035	0.0905	1.064	0.72%	0.9369	<10%	yes	128.6
Upper Stout Lake	76.3	0.0038	0.1045	0.671	2.24%	1.7122	<10%	yes	74.6
Glacier Lake (Colorado)	63.4	0.0023	0.0741	1.145	1.12%	0.7081	<10%	yes	62.7
Lake South of Blue Lakes	16.9	0.0025	0.0965	1.312	4.74%	0.8013	<1(µeq/L)	yes	16.1
Big Eldorado Lake	19.6	0.0021	0.0637	1.128	3.15%	0.6190	<1(µeq/L)	yes	19.0
Four Mile Pothole	123.4	0.0029	0.0926	1.173	0.70%	0.8647	<10%	yes	122.5
Lake Due South of Ute Lake	13.2	0.0020	0.0617	1.067	4.82%	0.6346	<1(µeq/L)	yes	12.5
Little Eldorado	-3.3	0.0021	0.0637	1.128	18.76%	0.6190	<1(µeq/L)	yes	-3.9
Little Granite Lake	80.7	0.0019	0.0729	0.830	1.19%	0.9583	<10%	yes	79.8
Lower Sunlight Lake	80.9	0.0027	0.0734	1.177	0.85%	0.6867	<10%	yes	80.2
Middle Ute Lake	42.8	0.0019	0.0589	1.052	1.43%	0.6132	<10%	yes	42.2
Small Pond Above Trout Lake	25.5	0.0021	0.0746	1.087	2.94%	0.7494	<10%	yes	24.7
Upper Grizzly Lake	29.9	0.0031	0.0766	1.177	2.40%	0.7182	<10%	yes	29.2
Upper Sunlight Lake	28.0	0.0031	0.0766	1.177	2.57%	0.7182	<10%	yes	27.3
West Snowdon Lake	39.4	0.0015	0.0616	0.978	1.74%	0.6863	<10%	yes	38.7
White Dome Lake	2.1	0.0021	0.0637	1.128	30.05%	0.6190	<1(µeq/L)	yes	1.4
South Golden Lake	111.4	0.0053	0.1712	0.984	1.71%	1.9060	<10%	yes	109.5

* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

Table 5-37b. ANC calculations at sensitive lakes for new Federal oil and gas development and mining and new non-Federal oil and gas within the 14 Colorado and northern New Mexico BLM Planning Areas (Source Group T) and the 2021 Low Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Hi Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0039	0.0528	0.898	0.66%	0.6663	<10%	yes	101.0
Tabor Lake	112.4	0.0038	0.0529	0.860	0.62%	0.6973	<10%	yes	111.7
Booth Lake	86.8	0.0050	0.0745	0.844	1.15%	0.9959	<10%	yes	85.8
Upper Willow Lake	134.1	0.0042	0.0544	0.741	0.62%	0.8349	<10%	yes	133.3
Ned Wilson Lake	39.0	0.0123	0.0913	1.158	2.41%	0.9397	<10%	yes	38.1
Upper Ned Wilson Lake	12.9	0.0123	0.0913	1.158	7.30%	0.9397	<1(µeq/L)	yes	11.9
Lower NWL Packtrail Pothole	29.7	0.0123	0.0913	1.158	3.17%	0.9397	<10%	yes	28.7
Upper NWL Packtrail Pothole	48.7	0.0123	0.0913	1.158	1.93%	0.9397	<10%	yes	47.8
Walk Up Lake	55.2	0.0001	0.0023	0.878	0.05%	0.0293	<10%	yes	55.2
Bluebell Lake	55.5	0.0001	0.0016	0.883	0.04%	0.0203	<10%	yes	55.5
Dean Lake	48.9	0.0000	0.0013	1.061	0.03%	0.0139	<10%	yes	48.9
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0001	0.0029	0.844	0.06%	0.0383	<10%	yes	67.0
Upper Coffin Lake	64.9	0.0001	0.0017	0.960	0.03%	0.0197	<10%	yes	64.8
Fish Lake	105.8	0.0001	0.0022	0.869	0.03%	0.0283	<10%	yes	105.7
Blodgett Lake, Colorado	47.7	0.0052	0.0757	0.928	1.93%	0.9220	<10%	yes	46.7
Upper Turquoise Lake	104.0	0.0061	0.0804	0.809	1.09%	1.1299	<10%	yes	102.9
Upper West Tennessee Lake	114.2	0.0038	0.0606	0.904	0.66%	0.7537	<10%	yes	113.4
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0086	0.0832	1.128	4.45%	0.8574	<1(µeq/L)	yes	18.4
Crater Lake	53.1	0.0093	0.0713	1.071	1.49%	0.7904	<10%	yes	52.3
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0091	0.0791	0.959	1.85%	0.9676	<10%	yes	51.3
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0095	0.0922	1.126	3.71%	0.9507	<10%	yes	24.7
Upper Lake	69.0	0.0092	0.0751	1.139	1.13%	0.7789	<10%	yes	68.2
Small Lake Above U-Shaped Lake	59.9	0.0013	0.0341	0.927	0.68%	0.4050	<10%	yes	59.5
U-Shaped Lake	81.4	0.0013	0.0341	0.927	0.50%	0.4050	<10%	yes	81.0
Avalanche Lake	158.8	0.0083	0.0864	1.282	0.49%	0.7788	<10%	yes	158.0
Capitol Lake	154.4	0.0081	0.0855	1.110	0.58%	0.8892	<10%	yes	153.5
Moon Lake (Upper)	53.0	0.0081	0.0855	1.110	1.68%	0.8892	<10%	yes	52.1
Upper Middle Beartrack Lake	50.9	0.0038	0.0610	0.869	1.55%	0.7890	<10%	yes	50.1
Abyss Lake	81.1	0.0035	0.0561	0.896	0.87%	0.7037	<10%	yes	80.4
Frozen Lake	93.3	0.0035	0.0561	0.896	0.75%	0.7037	<10%	yes	92.6
North Lake	80.9	0.0035	0.0561	0.896	0.87%	0.7037	<10%	yes	80.2
South Lake	66.7	0.0035	0.0561	0.896	1.05%	0.7037	<10%	yes	66.0
Lake Elbert	56.6	0.0221	0.0776	1.726	1.06%	0.5989	<10%	yes	56.0
Seven Lakes (LG East)	36.2	0.0142	0.0627	1.546	1.43%	0.5180	<10%	yes	35.7
Summit Lake	48.0	0.0258	0.0770	1.449	1.53%	0.7325	<10%	yes	47.3
Deep Creek Lake	20.6	0.0072	0.0713	0.887	4.53%	0.9324	<1(µeq/L)	yes	19.7
Island Lake	71.0	0.0100	0.0541	1.079	0.87%	0.6214	<10%	yes	70.4
Kelly Lake	179.9	0.0100	0.0541	1.079	0.35%	0.6214	<10%	yes	179.2
Rawah Lake #4	41.3	0.0096	0.0563	1.098	1.52%	0.6284	<10%	yes	40.7
Crater Lake (Sangre de Cristo)	162.9	0.0019	0.0460	0.959	0.32%	0.5292	<10%	yes	162.4
Lower Stout Lake	145.2	0.0019	0.0459	0.671	0.52%	0.7565	<10%	yes	144.4
Upper Little Sand Creek Lake	129.5	0.0019	0.0437	1.064	0.35%	0.4542	<10%	yes	129.0
Upper Stout Lake	76.3	0.0019	0.0459	0.671	0.99%	0.7565	<10%	yes	75.6
Glacier Lake (Colorado)	63.4	0.0014	0.0524	1.145	0.79%	0.4991	<10%	yes	62.9
Lake South of Blue Lakes	16.9	0.0016	0.0695	1.312	3.41%	0.5762	<1(µeq/L)	yes	16.3
Big Eldorado Lake	19.6	0.0011	0.0348	1.128	1.72%	0.3385	<1(µeq/L)	yes	19.3
Four Mile Pothole	123.4	0.0019	0.0647	1.173	0.49%	0.6038	<10%	yes	122.8
Lake Due South of Ute Lake	13.2	0.0012	0.0375	1.067	2.93%	0.3854	<1(µeq/L)	yes	12.8
Little Eldorado	-3.3	0.0011	0.0348	1.128	10.26%	0.3385	<1(µeq/L)	yes	-3.6
Little Granite Lake	80.7	0.0012	0.0454	0.830	0.74%	0.5965	<10%	yes	80.1
Lower Sunlight Lake	80.9	0.0015	0.0424	1.177	0.49%	0.3963	<10%	yes	80.5
Middle Ute Lake	42.8	0.0010	0.0347	1.052	0.84%	0.3608	<10%	yes	42.4
Small Pond Above Trout Lake	25.5	0.0012	0.0465	1.087	1.83%	0.4667	<10%	yes	25.0
Upper Grizzly Lake	29.9	0.0018	0.0450	1.177	1.41%	0.4219	<10%	yes	29.5
Upper Sunlight Lake	28.0	0.0018	0.0450	1.177	1.51%	0.4219	<10%	yes	27.6
West Snowdon Lake	39.4	0.0007	0.0330	0.978	0.93%	0.3666	<10%	yes	39.0
White Dome Lake	2.1	0.0011	0.0348	1.128	16.43%	0.3385	<1(µeq/L)	yes	1.7
South Golden Lake	111.4	0.0031	0.0571	0.984	0.58%	0.6489	<10%	yes	110.8

* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC

Table 5-37c. ANC calculations at sensitive lakes for new Federal oil and gas development and mining and new non-Federal oil and gas within the 14 Colorado and northern New Mexico BLM Planning Areas (Source Group T) and the 2021 Medium Development Scenario.

Lake	10th Percentile Lowest ANC Value (µeq/L)	Total S Dep (kg-S/ha-yr)	Total N Dep (kg-N/ha-yr)	PPT (m)	Delta ANC (%) [*]	Delta ANC (µeq/L) [*]	USFS LAC Threshold	Below Threshold?	2021 Med Predicted 10th Percentile Lowest ANC Value (µeq/L)
Brooklyn Lake	101.7	0.0071	0.1347	0.898	1.64%	1.6718	<10%	yes	100.0
Tabor Lake	112.4	0.0069	0.1372	0.860	1.58%	1.7763	<10%	yes	110.6
Booth Lake	86.8	0.0088	0.1928	0.844	2.92%	2.5307	<10%	yes	84.2
Upper Willow Lake	134.1	0.0070	0.1413	0.741	1.58%	2.1223	<10%	yes	132.0
Ned Wilson Lake	39.0	0.0217	0.2423	1.158	6.17%	2.4048	<10%	yes	36.6
Upper Ned Wilson Lake	12.9	0.0217	0.2423	1.158	18.67%	2.4048	<1(µeq/L)	no	10.5
Lower NWL Packtrail Pothole	29.7	0.0217	0.2423	1.158	8.11%	2.4048	<10%	yes	27.2
Upper NWL Packtrail Pothole	48.7	0.0217	0.2423	1.158	4.94%	2.4048	<10%	yes	46.3
Walk Up Lake	55.2	0.0003	0.0057	0.878	0.13%	0.0728	<10%	yes	55.2
Bluebell Lake	55.5	0.0001	0.0036	0.883	0.08%	0.0449	<10%	yes	55.5
Dean Lake	48.9	0.0001	0.0031	1.061	0.07%	0.0322	<10%	yes	48.8
No Name (Utah, Duchesne - 4D2-039)	67.0	0.0004	0.0070	0.844	0.14%	0.0924	<10%	yes	66.9
Upper Coffin Lake	64.9	0.0002	0.0041	0.960	0.07%	0.0469	<10%	yes	64.8
Fish Lake	105.8	0.0003	0.0055	0.869	0.07%	0.0708	<10%	yes	105.7
Blodgett Lake, Colorado	47.7	0.0094	0.1971	0.928	4.95%	2.3588	<10%	yes	45.3
Upper Turquoise Lake	104.0	0.0109	0.2084	0.809	2.76%	2.8736	<10%	yes	101.1
Upper West Tennessee Lake	114.2	0.0068	0.1588	0.904	1.70%	1.9433	<10%	yes	112.3
Blue Lake (Colorado; Boulder - 4E1-040)	19.3	0.0133	0.2273	1.128	11.73%	2.2589	<1(µeq/L)	no	17.0
Crater Lake	53.1	0.0137	0.1964	1.071	3.91%	2.0754	<10%	yes	51.1
King Lake (Colorado; Grand - 4E1-049)	52.3	0.0135	0.2170	0.959	4.87%	2.5434	<10%	yes	49.7
No Name Lake (Colorado; Boulder - 4E1-055)	25.6	0.0146	0.2490	1.126	9.67%	2.4781	<10%	yes	23.1
Upper Lake	69.0	0.0146	0.2069	1.139	2.98%	2.0569	<10%	yes	66.9
Small Lake Above U-Shaped Lake	59.9	0.0022	0.0636	0.927	1.26%	0.7533	<10%	yes	59.1
U-Shaped Lake	81.4	0.0022	0.0636	0.927	0.93%	0.7533	<10%	yes	80.6
Avalanche Lake	158.8	0.0135	0.2321	1.282	1.28%	2.0283	<10%	yes	156.8
Capitol Lake	154.4	0.0135	0.2281	1.110	1.49%	2.3031	<10%	yes	152.1
Moon Lake (Upper)	53.0	0.0135	0.2281	1.110	4.35%	2.3031	<10%	yes	50.7
Upper Middle Beartrack Lake	50.9	0.0068	0.1541	0.869	3.86%	1.9647	<10%	yes	48.9
Abyss Lake	81.1	0.0062	0.1432	0.896	2.18%	1.7692	<10%	yes	79.3
Frozen Lake	93.3	0.0062	0.1432	0.896	1.90%	1.7692	<10%	yes	91.5
North Lake	80.9	0.0062	0.1432	0.896	2.19%	1.7692	<10%	yes	79.2
South Lake	66.7	0.0062	0.1432	0.896	2.65%	1.7692	<10%	yes	65.0
Lake Elbert	56.6	0.0311	0.2264	1.726	2.77%	1.5664	<10%	yes	55.0
Seven Lakes (LG East)	36.2	0.0222	0.1859	1.546	3.91%	1.4167	<10%	yes	34.8
Summit Lake	48.0	0.0343	0.2262	1.449	3.93%	1.8847	<10%	yes	46.1
Deep Creek Lake	20.6	0.0109	0.1950	0.887	11.93%	2.4569	<1(µeq/L)	no	18.1
Island Lake	71.0	0.0153	0.1536	1.079	2.33%	1.6514	<10%	yes	69.4
Kelly Lake	179.9	0.0153	0.1536	1.079	0.92%	1.6514	<10%	yes	178.2
Rawah Lake #4	41.3	0.0149	0.1591	1.098	4.05%	1.6719	<10%	yes	39.6
Crater Lake (Sangre de Cristo)	162.9	0.0033	0.0837	0.959	0.59%	0.9634	<10%	yes	162.0
Lower Stout Lake	145.2	0.0037	0.0943	0.671	1.07%	1.5492	<10%	yes	143.7
Upper Little Sand Creek Lake	129.5	0.0034	0.0814	1.064	0.65%	0.8447	<10%	yes	128.7
Upper Stout Lake	76.3	0.0037	0.0943	0.671	2.03%	1.5492	<10%	yes	74.8
Glacier Lake (Colorado)	63.4	0.0021	0.0646	1.145	0.98%	0.6183	<10%	yes	62.8
Lake South of Blue Lakes	16.9	0.0023	0.0839	1.312	4.13%	0.6979	<1(µeq/L)	yes	16.2
Big Eldorado Lake	19.6	0.0020	0.0565	1.128	2.80%	0.5499	<1(µeq/L)	yes	19.1
Four Mile Pothole	123.4	0.0027	0.0802	1.173	0.61%	0.7502	<10%	yes	122.6
Lake Due South of Ute Lake	13.2	0.0019	0.0543	1.067	4.25%	0.5593	<1(µeq/L)	yes	12.6
Little Eldorado	-3.3	0.0020	0.0565	1.128	16.66%	0.5499	<1(µeq/L)	yes	-3.8
Little Granite Lake	80.7	0.0018	0.0639	0.830	1.04%	0.8408	<10%	yes	79.9
Lower Sunlight Lake	80.9	0.0026	0.0649	1.177	0.75%	0.6080	<10%	yes	80.3
Middle Ute Lake	42.8	0.0018	0.0519	1.052	1.27%	0.5419	<10%	yes	42.2
Small Pond Above Trout Lake	25.5	0.0020	0.0653	1.087	2.58%	0.6573	<10%	yes	24.8
Upper Grizzly Lake	29.9	0.0030	0.0675	1.177	2.13%	0.6352	<10%	yes	29.2
Upper Sunlight Lake	28.0	0.0030	0.0675	1.177	2.27%	0.6352	<10%	yes	27.4
West Snowdon Lake	39.4	0.0014	0.0548	0.978	1.55%	0.6107	<10%	yes	38.7
White Dome Lake	2.1	0.0020	0.0565	1.128	26.69%	0.5499	<1(µeq/L)	yes	1.5
South Golden Lake	111.4	0.0052	0.1515	0.984	1.52%	1.6909	<10%	yes	109.7
* USDA Forest Service methodology reports both Delta ANC calculations and LAC thresholds as positive quantities, however they reflect a decrease in lake ANC									

5.6 2021 NAAQS Comparisons

In this section we compare the CAMx 2021 High, Low and Medium Development Scenario modeling results against the National Ambient Air Quality Standard (NAAQS). For the ozone NAAQS analysis, the results are analyzed using both the absolute CAMx 2021 modeling results as well as using the CAMx 2008 and 2021 modeling results in a relative fashion to scale the observed current year Design Values (DVC) to project future year 2021 Design Values (DVF) as recommended by EPA (2007) and described in Section 4.5.

5.6.1 Ozone NAAQS Analysis using Relative Modeling Results

EPA's Model Attainment Test Software (MATS) was used to make future year ozone Design Value (DV) projections using the CAMx 2008 Base Case and 2021 High and Low Development Scenario modeling results. MATS was also used to make future year 2021 ozone DV (DVF) projections for the 2021 High and Low Development Scenario removing the contributions of four of the combined Source Groups R, S, T and U. MATS was used to make 2021 ozone DVF projections at the monitoring sites as well as throughout the CARMMS modeling domain using the MATS Unmonitored Area Analysis (UAA) procedures.

5.6.1.1 Ozone Design Value Projections at Monitoring Sites

The results of the 2021 ozone DVF projections at the monitoring sites are given in Attachments F-1, F-2 and F-3 and shown in Table 5-39. The maximum current year DVC (DVC; based on 2006-2010 observations) is 82.0 ppb at the Rocky Flats North (CO_Jefferson_006) monitor that is projected to be reduced to 79.5, 78.1 and 79.5 ppb for the 2021 High, Low and Medium Development Scenarios, respectively. There are 8 monitoring sites in the CARMMS 4 km domain with current year DVCs above the ozone NAAQS that are reduced to two sites in the 2021 emission scenarios, Rocky Flats North and Fort Collins West (CO_Larimer_0011). Removing the contributions due to new O&G and mining on Federal lands within the 13 Colorado BLM Planning Areas (Source Group R) reduces the 2021 DVF at Rocky Flats North by 0.9 ppb to 78.6 ppb for the High, by 0.3 ppb to 77.8 ppb for the Low and by 0.8 ppb to 78.7 ppb for the Medium Development Scenarios, which are still above the ozone NAAQS (76.0 ppb or higher). However, when emissions from new non-Federal O&G within the 13 Colorado Planning Areas are also removed (Source Group S), the projected 2021 DVFs are 74.5, 75.8 and 74.5 ppb for the High, Low and Medium Development Scenarios. The maximum reduction in 2021 DVFs due to the removal of Source Group R at any monitor is 0.9 ppb at the Rocky Flats North and South Bolder Creek (CO_Boulder_0011) monitoring site for the High Development Scenario. Whereas maximum reduction from removing Source Group R for the Low and Medium Scenarios are 0.3 and 0.8 ppb at Rocky Flats North. The maximum reduction in 2021 DVF due to the removal of Source Group S, T and U in the High Development Scenario are, respectively, 7.2, 7.3 and 9.0 ppb at the Greeley – Weld Tower (CO_Weld_009) monitoring site. Most of the O&G development in Weld County (Royal Gorge FO Area#1; Source Group I) is on non-Federal lands so the monitors in Weld County are less affected by the Federal O&G development (Source Group R).

Table 5-39a. Current year ozone Design Values (DVC) and projected 2021 future year ozone Design Values (DVF) for the 2021 High Development Scenario and without Source Group R, S, T and U.

CID	Name	Lat	Long	State	County	DVC	DVF					Contribution from			
							2021 Hi	2021 Hi w/o R	2021 Hi w/o S	2021 Hi w/o T	2021 Hi w/o U	Group R	Group S	Group T	Group U
080013001	CO Adams_0001	39.8381	-104.9498	Colorado	Adams	71.5	70.5	69.7	67.2	67.2	65.6	0.8	3.3	3.3	4.9
080130011	CO Boulder_0011	39.9572	-105.2385	Colorado	Boulder	77.3	74.4	73.5	69.0	69.0	66.8	0.9	5.4	5.4	7.6
080310014	CO Denver_0014	39.7518	-105.0307	Colorado	Denver	70.3	69.0	68.3	66.2	66.2	64.8	0.7	2.8	2.8	4.2
080350004	CO Douglas_0004	39.5345	-105.0704	Colorado	Douglas	78.3	75.7	74.9	72.3	72.3	70.7	0.8	3.4	3.4	5.0
080410013	CO El Paso_0013	38.9583	-104.8172	Colorado	El Paso	68.0	66.0	65.4	64.5	64.5	63.3	0.6	1.5	1.5	2.7
080410016	CO El Paso_0016	38.8531	-104.9013	Colorado	El Paso	70.3	68.8	68.4	67.7	67.6	66.4	0.4	1.1	1.2	2.4
080590002	CO Jefferson_0002	39.8003	-105.1000	Colorado	Jefferson	75.0	73.5	72.6	70.0	70.0	68.4	0.9	3.5	3.5	5.1
080590005	CO Jefferson_0005	39.6388	-105.1395	Colorado	Jefferson	74.3	72.4	71.8	70.0	70.0	68.8	0.6	2.4	2.4	3.6
080590006	CO Jefferson_0006	39.9128	-105.1886	Colorado	Jefferson	82.0	79.5	78.6	74.5	74.5	72.4	0.9	5.0	5.0	7.1
080590011	CO Jefferson_0011	39.7437	-105.1780	Colorado	Jefferson	76.3	74.0	73.3	71.0	71.0	69.7	0.7	3.0	3.0	4.3
080671004	CO La Plata_1004	37.3039	-107.4842	Colorado	La Plata	70.0	69.8	69.5	69.3	69.3	68.9	0.3	0.5	0.5	0.9
080677001	CO La Plata_7001	37.1368	-107.6286	Colorado	La Plata	66.0	65.9	65.5	65.1	64.8	61.6	0.4	0.8	1.1	4.3
080677003	CO La Plata_7003	37.1026	-107.8702	Colorado	La Plata	67.0	66.8	66.4	66.0	65.8	62.9	0.4	0.8	1.0	3.9
080690007	CO Larimer_0007	40.2772	-105.5450	Colorado	Larimer	74.3	72.7	72.4	70.1	70.1	68.9	0.3	2.6	2.6	3.8
080690011	CO Larimer_0011	40.5925	-105.1411	Colorado	Larimer	78.0	78.9	78.6	73.5	73.5	72.1	0.3	5.4	5.4	6.8
080691004	CO Larimer_1004	40.5775	-105.0789	Colorado	Larimer	67.3	67.4	67.2	62.9	62.9	61.7	0.2	4.5	4.5	5.7
080830101	CO Montezuma_0101	37.1983	-108.4903	Colorado	Montezuma	69.3	68.9	68.6	68.3	68.3	66.5	0.3	0.6	0.6	2.4
081230009	CO Weld_0009	40.3864	-104.7374	Colorado	Weld	72.7	72.1	71.5	64.9	64.8	63.1	0.6	7.2	7.3	9.0
350010023	NM Bernalillo_0023	35.1343	-106.5852	New Mexico	Bernalillo	66.0	63.8	63.6	63.5	63.4	62.4	0.2	0.3	0.4	1.4
350010024	NM Bernalillo_0024	35.0631	-106.5788	New Mexico	Bernalillo	67.3	64.8	64.7	64.5	64.5	63.5	0.1	0.3	0.3	1.3
350010027	NM Bernalillo_0027	35.1539	-106.6972	New Mexico	Bernalillo	68.3	64.7	64.6	64.5	64.5	63.7	0.1	0.2	0.2	1.0
350010029	NM Bernalillo_0029	35.0171	-106.6574	New Mexico	Bernalillo	67.0	64.8	64.6	64.5	64.5	63.5	0.2	0.3	0.3	1.3
350011012	NM Bernalillo_1012	35.1852	-106.5082	New Mexico	Bernalillo	69.0	66.7	66.5	66.3	66.3	65.2	0.2	0.4	0.4	1.5
350011013	NM Bernalillo_1013	35.1932	-106.6138	New Mexico	Bernalillo	68.7	66.0	65.9	65.7	65.7	64.6	0.1	0.3	0.3	1.4
350431001	NM Sandoval_1001	35.2994	-106.5483	New Mexico	Sandoval	60.3	58.3	58.1	58.0	57.9	56.9	0.2	0.3	0.4	1.4
350431003	NM Sandoval_1003	35.2381	-106.6494	New Mexico	Sandoval	70.0	67.2	67.1	66.9	66.9	65.8	0.1	0.3	0.3	1.4
350439004	NM Sandoval_9004	35.6153	-106.7244	New Mexico	Sandoval	68.0	67.8	67.5	67.2	67.1	65.4	0.3	0.6	0.7	2.4
350450009	NM San Juan_0009	36.7422	-107.9769	New Mexico	San Juan	62.0	61.0	60.8	60.3	60.3	55.6	0.2	0.5	0.7	5.4
350451005	NM San Juan_1005	36.7967	-108.4725	New Mexico	San Juan	67.0	65.9	65.5	65.0	64.8	61.2	0.4	0.9	1.1	4.7
490110004	UT Davis_0004	40.9030	-111.8845	Utah	Davis	77.0	74.5	74.5	74.4	74.4	74.2	0.0	0.1	0.1	0.3
490350003	UT Salt Lake_0003	40.6467	-111.8497	Utah	Salt Lake	78.0	75.8	75.8	75.8	75.8	75.6	0.0	0.0	0.0	0.2
490352004	UT Salt Lake_2004	40.7364	-112.2103	Utah	Salt Lake	75.7	73.3	73.3	73.3	73.3	73.1	0.0	0.0	0.0	0.2
490353006	UT Salt Lake_3006	40.7364	-111.8722	Utah	Salt Lake	77.0	74.3	74.3	74.3	74.3	74.1	0.0	0.0	0.0	0.2
490370101	UT San Juan_0101	38.4500	-109.8167	Utah	San Juan	70.0	69.2	69.1	69.0	69.0	68.5	0.1	0.2	0.2	0.7
490490002	UT Utah_0002	40.2536	-111.6631	Utah	Utah	72.0	70.3	70.3	70.3	70.3	70.2	0.0	0.0	0.0	0.1
490495008	UT Utah_5008	40.4303	-111.8039	Utah	Utah	72.3	70.4	70.4	70.4	70.4	70.3	0.0	0.0	0.0	0.1
490495010	UT Utah_5010	40.1364	-111.6597	Utah	Utah	72.3	70.3	70.3	70.3	70.3	70.2	0.0	0.0	0.0	0.1

Table 5-39b. Current year ozone Design Values (DVC) and projected 2021 future year ozone Design Values (DVF) for the 2021 Low Development Scenario and without Source Group R, S, T and U.

CID	Name	Lat	Long	State	County	DVC	DVF					Contribution from			
							2021 Low	2021 Low w/o R	2021 Low w/o S	2021 Low w/o T	2021 Low w/o U	Group R	Group S	Group T	Group U
080013001	CO Adams_0001	39.8381	-104.9498	Colorado	Adams	71.5	69.6	69.4	68.1	68.1	66.3	0.2	1.5	1.5	3.3
080130011	CO Boulder_0011	39.9572	-105.2385	Colorado	Boulder	77.3	72.8	72.6	70.3	70.2	67.9	0.2	2.5	2.6	4.9
080310014	CO Denver_0014	39.7518	-105.0307	Colorado	Denver	70.3	68.2	68.0	67.0	66.9	65.5	0.2	1.2	1.3	2.7
080350004	CO Douglas_0004	39.5345	-105.0704	Colorado	Douglas	78.3	74.7	74.5	73.2	73.2	71.5	0.2	1.5	1.5	3.2
080410013	CO El Paso_0013	38.9583	-104.8172	Colorado	El Paso	68.0	65.6	65.5	65.0	64.9	63.7	0.1	0.6	0.7	1.9
080410016	CO El Paso_0016	38.8531	-104.9013	Colorado	El Paso	70.3	68.6	68.5	68.1	68.0	66.8	0.1	0.5	0.6	1.8
080590002	CO Jefferson_0002	39.8003	-105.1000	Colorado	Jefferson	75.0	72.5	72.3	70.9	70.9	69.2	0.2	1.6	1.6	3.3
080590005	CO Jefferson_0005	39.6388	-105.1395	Colorado	Jefferson	74.3	71.7	71.5	70.6	70.6	69.3	0.2	1.1	1.1	2.4
080590006	CO Jefferson_0006	39.9128	-105.1886	Colorado	Jefferson	82.0	78.1	77.8	75.8	75.8	73.4	0.3	2.3	2.3	4.7
080590011	CO Jefferson_0011	39.7437	-105.1780	Colorado	Jefferson	76.3	73.2	73.1	71.9	71.8	70.4	0.1	1.3	1.4	2.8
080671004	CO La Plata_1004	37.3039	-107.4842	Colorado	La Plata	70.0	69.7	69.6	69.4	69.4	69.0	0.1	0.3	0.3	0.7
080677001	CO La Plata_7001	37.1368	-107.6286	Colorado	La Plata	66.0	65.7	65.7	65.3	65.0	61.8	0.0	0.4	0.7	3.9
080677003	CO La Plata_7003	37.1026	-107.8702	Colorado	La Plata	67.0	66.7	66.6	66.2	66.0	63.1	0.1	0.5	0.7	3.6
080690007	CO Larimer_0007	40.2772	-105.5450	Colorado	Larimer	74.3	71.9	71.9	70.7	70.7	69.3	0.0	1.2	1.2	2.6
080690011	CO Larimer_0011	40.5925	-105.1411	Colorado	Larimer	78.0	77.2	77.2	73.9	73.9	72.0	0.0	3.3	3.3	5.2
080691004	CO Larimer_1004	40.5775	-105.0789	Colorado	Larimer	67.3	66.0	65.9	63.2	63.2	61.7	0.1	2.8	2.8	4.3
080830101	CO Montezuma_0101	37.1983	-108.4903	Colorado	Montezuma	69.3	68.8	68.7	68.5	68.4	66.6	0.1	0.3	0.4	2.2
081230009	CO Weld_0009	40.3864	-104.7374	Colorado	Weld	72.7	70.3	70.1	66.0	66.0	63.5	0.2	4.3	4.3	6.8
350010023	NM Bernalillo_0023	35.1343	-106.5852	New Mexico	Bernalillo	66.0	63.7	63.7	63.6	63.5	62.5	0.0	0.1	0.2	1.2
350010024	NM Bernalillo_0024	35.0631	-106.5788	New Mexico	Bernalillo	67.3	64.8	64.7	64.6	64.6	63.5	0.1	0.2	0.2	1.3
350010027	NM Bernalillo_0027	35.1539	-106.6972	New Mexico	Bernalillo	68.3	64.7	64.7	64.6	64.5	63.7	0.0	0.1	0.2	1.0
350010029	NM Bernalillo_0029	35.0171	-106.6574	New Mexico	Bernalillo	67.0	64.7	64.7	64.6	64.6	63.6	0.0	0.1	0.1	1.1
350011012	NM Bernalillo_1012	35.1852	-106.5082	New Mexico	Bernalillo	69.0	66.6	66.6	66.4	66.4	65.3	0.0	0.2	0.2	1.3
350011013	NM Bernalillo_1013	35.1932	-106.6138	New Mexico	Bernalillo	68.7	66.0	65.9	65.8	65.8	64.7	0.1	0.2	0.2	1.3
350431001	NM Sandoval_1001	35.2994	-106.5483	New Mexico	Sandoval	60.3	58.2	58.2	58.1	58.0	56.9	0.0	0.1	0.2	1.3
350431003	NM Sandoval_1003	35.2381	-106.6494	New Mexico	Sandoval	70.0	67.2	67.2	67.0	67.0	65.9	0.0	0.2	0.2	1.3
350439004	NM Sandoval_9004	35.6153	-106.7244	New Mexico	Sandoval	68.0	67.7	67.6	67.4	67.3	65.5	0.1	0.3	0.4	2.2
350450009	NM San Juan_0009	36.7422	-107.9769	New Mexico	San Juan	62.0	60.9	60.9	60.6	60.4	55.7	0.0	0.3	0.5	5.2
350451005	NM San Juan_1005	36.7967	-108.4725	New Mexico	San Juan	67.0	65.7	65.6	65.2	65.1	61.4	0.1	0.5	0.6	4.3
490110004	UT Davis_0004	40.9030	-111.8845	Utah	Davis	77.0	74.5	74.5	74.5	74.5	74.3	0.0	0.0	0.0	0.2
490350003	UT Salt Lake_0003	40.6467	-111.8497	Utah	Salt Lake	78.0	75.8	75.8	75.8	75.8	75.6	0.0	0.0	0.0	0.2
490352004	UT Salt Lake_2004	40.7364	-112.2103	Utah	Salt Lake	75.7	73.3	73.3	73.3	73.3	73.1	0.0	0.0	0.0	0.2
490353006	UT Salt Lake_3006	40.7364	-111.8722	Utah	Salt Lake	77.0	74.3	74.3	74.3	74.3	74.1	0.0	0.0	0.0	0.2
490370101	UT San Juan_0101	38.4500	-109.8167	Utah	San Juan	70.0	69.2	69.1	69.1	69.1	68.5	0.1	0.1	0.1	0.7
490490002	UT Utah_0002	40.2536	-111.6631	Utah	Utah	72.0	70.3	70.3	70.3	70.3	70.2	0.0	0.0	0.0	0.1
490495008	UT Utah_5008	40.4303	-111.8039	Utah	Utah	72.3	70.4	70.4	70.4	70.4	70.3	0.0	0.0	0.0	0.1
490495010	UT Utah_5010	40.1364	-111.6597	Utah	Utah	72.3	70.3	70.3	70.3	70.3	70.2	0.0	0.0	0.0	0.1

Table 5-39c. Current year ozone Design Values (DVC) and projected 2021 future year ozone Design Values (DVF) for the 2021 Medium Development Scenario and without Source Group R, S, T and U.

CID	Name	Lat	Long	State	County	DVC	DVF					Contribution from			
							2021 Med	2021 Med w/o R	2021 Med w/o S	2021 Med w/o T	2021 Med w/o U	Group R	Group S	Group T	Group U
080013001	CO Adams 3001	39.8381	-104.9498	Colorado	Adams	71.5	70.5	69.8	67.3	67.2	65.6	0.7	3.2	3.3	4.9
080130011	CO Boulder 0011	39.9572	-105.2385	Colorado	Boulder	77.3	74.4	73.6	69.1	69.1	66.9	0.8	5.3	5.3	7.5
080310014	CO Denver 0014	39.7518	-105.0307	Colorado	Denver	70.3	69.0	68.3	66.2	66.2	64.9	0.7	2.8	2.8	4.1
080350004	CO Douglas 0004	39.5345	-105.0704	Colorado	Douglas	78.3	75.6	75.0	72.3	72.3	70.8	0.6	3.3	3.3	4.8
080410013	CO El Paso 0013	38.9583	-104.8172	Colorado	El Paso	68.0	66.0	65.5	64.5	64.5	63.3	0.5	1.5	1.5	2.7
080410016	CO El Paso 0016	38.8531	-104.9013	Colorado	El Paso	70.3	68.8	68.4	67.7	67.7	66.5	0.4	1.1	1.1	2.3
080590002	CO Jefferson 0002	39.8003	-105.1000	Colorado	Jefferson	75.0	73.4	72.6	70.0	70.0	68.5	0.8	3.4	3.4	4.9
080590005	CO Jefferson 0005	39.6388	-105.1395	Colorado	Jefferson	74.3	72.4	71.8	70.0	70.0	68.8	0.6	2.4	2.4	3.6
080590006	CO Jefferson 0006	39.9128	-105.1886	Colorado	Jefferson	82.0	79.5	78.7	74.5	74.5	72.4	0.8	5.0	5.0	7.1
080590011	CO Jefferson 0011	39.7437	-105.1780	Colorado	Jefferson	76.3	74.0	73.4	71.1	71.0	69.7	0.6	2.9	3.0	4.3
080671004	CO La Plata 1004	37.3039	-107.4842	Colorado	La Plata	70.0	69.8	69.5	69.3	69.3	68.9	0.3	0.5	0.5	0.9
080677001	CO La Plata 7001	37.1368	-107.6286	Colorado	La Plata	66.0	65.8	65.5	65.1	64.9	61.6	0.3	0.7	0.9	4.2
080677003	CO La Plata 7003	37.1026	-107.8702	Colorado	La Plata	67.0	66.8	66.4	66.0	65.9	62.9	0.4	0.8	0.9	3.9
080690007	CO Larimer 0007	40.2772	-105.5450	Colorado	Larimer	74.3	72.7	72.5	70.2	70.1	69.0	0.2	2.5	2.6	3.7
080690011	CO Larimer 0011	40.5925	-105.1411	Colorado	Larimer	78.0	78.9	78.7	73.5	73.5	72.1	0.2	5.4	5.4	6.8
080691004	CO Larimer 1004	40.5775	-105.0789	Colorado	Larimer	67.3	67.4	67.2	62.9	62.9	61.7	0.2	4.5	4.5	5.7
080830101	CO Montezuma 0101	37.1983	-108.4903	Colorado	Montezuma	69.3	68.9	68.6	68.3	68.3	66.5	0.3	0.6	0.6	2.4
081230009	CO Weld 0009	40.3864	-104.7374	Colorado	Weld	72.7	72.0	71.5	64.9	64.9	63.1	0.5	7.1	7.1	8.9
350010023	NM Bernalillo 0023	35.1343	-106.5852	New Mexico	Bernalillo	66.0	63.8	63.6	63.5	63.5	62.4	0.2	0.3	0.3	1.4
350010024	NM Bernalillo 0024	35.0631	-106.5788	New Mexico	Bernalillo	67.3	64.8	64.7	64.5	64.5	63.5	0.1	0.3	0.3	1.3
350010027	NM Bernalillo 0027	35.1539	-106.6972	New Mexico	Bernalillo	68.3	64.7	64.6	64.5	64.5	63.7	0.1	0.2	0.2	1.0
350010029	NM Bernalillo 0029	35.0171	-106.6574	New Mexico	Bernalillo	67.0	64.8	64.6	64.5	64.5	63.6	0.2	0.3	0.3	1.2
350011012	NM Bernalillo 1012	35.1852	-106.5082	New Mexico	Bernalillo	69.0	66.7	66.5	66.3	66.3	65.2	0.2	0.4	0.4	1.5
350011013	NM Bernalillo 1013	35.1932	-106.6138	New Mexico	Bernalillo	68.7	66.0	65.9	65.7	65.7	64.7	0.1	0.3	0.3	1.3
350431001	NM Sandoval 1001	35.2994	-106.5483	New Mexico	Sandoval	60.3	58.3	58.1	58.0	58.0	56.9	0.2	0.3	0.3	1.4
350431003	NM Sandoval 1003	35.2381	-106.6494	New Mexico	Sandoval	70.0	67.2	67.1	67.0	66.9	65.8	0.1	0.2	0.3	1.4
350439004	NM Sandoval 9004	35.6153	-106.7244	New Mexico	Sandoval	68.0	67.8	67.5	67.2	67.1	65.4	0.3	0.6	0.7	2.4
350450009	NM San Juan 0009	36.7422	-107.9769	New Mexico	San Juan	62.0	61.0	60.8	60.5	60.3	55.7	0.2	0.5	0.7	5.3
350451005	NM San Juan 1005	36.7967	-108.4725	New Mexico	San Juan	67.0	65.8	65.5	65.0	64.9	61.2	0.3	0.8	0.9	4.6
490110004	UT Davis 0004	40.9030	-111.8845	Utah	Davis	77.0	74.5	74.5	74.4	74.4	74.2	0.0	0.1	0.1	0.3
490350003	UT Salt Lake 0003	40.6467	-111.8497	Utah	Salt Lake	78.0	75.8	75.8	75.8	75.8	75.6	0.0	0.0	0.0	0.2
490352004	UT Salt Lake 2004	40.7364	-112.2103	Utah	Salt Lake	75.7	73.3	73.3	73.3	73.3	73.1	0.0	0.0	0.0	0.2
490353006	UT Salt Lake 3006	40.7364	-111.8722	Utah	Salt Lake	77.0	74.3	74.3	74.3	74.3	74.1	0.0	0.0	0.0	0.2
490370101	UT San Juan 0101	38.4500	-109.8167	Utah	San Juan	70.0	69.2	69.1	69.0	69.0	68.5	0.1	0.2	0.2	0.7
490490002	UT Utah 0002	40.2536	-111.6631	Utah	Utah	72.0	70.3	70.3	70.3	70.3	70.2	0.0	0.0	0.0	0.1
490495008	UT Utah 5008	40.4303	-111.8039	Utah	Utah	72.3	70.4	70.4	70.4	70.4	70.3	0.0	0.0	0.0	0.1
490495010	UT Utah 5010	40.1364	-111.6597	Utah	Utah	72.3	70.3	70.3	70.3	70.3	70.2	0.0	0.0	0.0	0.1

5.6.1.2 Ozone Design Value Projection Unmonitored Area Analysis

MATS was used to perform an unmonitored area analysis (UAA) of the 2021 ozone DVF projections for the 2021 High, Low and Medium Development Scenarios and the 2021 results without the contributions from the combined Source Groups R, S, T and U. The MATS UAA interpolates the current year observed ozone DVCs across the CARMMS 4 km domain and then makes 2021 ozone DVF projections throughout the domain using the relative change in the CAMx 2008 and 2021 modeling results in each 4 km grid cell. Figure 5-1 displays the spatial distribution of the MATS UAA derived 2008 ozone DVCs and 2021 ozone DVFs and their differences for the three 2021 emission scenarios. The color scheme for the spatial plots has a cut-point at 76.0 ppb so tiles that are yellow or warmer indicate exceedances of the 0.075 ppm ozone NAAQS. The current year DVCs indicate areas of ozone exceedances in Denver and Salt Lake City with a maximum DVC of 81.5 ppb just northwest of Denver (Figure 5-1, top left). For the 2021 High, Low and Medium Development Scenarios the areas of 2021 ozone DVF exceedances is reduced and limited to smaller areas in the Denver and SLC area and just east of SLC with a peak DVF of 79.3, 77.5 and 79.2 ppb for the 2021 High, Low and Medium Development Scenarios, respectively, just northwest of Denver near Rocky Flats North (top right in Figures 5-1a, 5-1b and 5-1c). The 2021 DVF – 2008 DVC difference plots (Figure 5-1, bottom) shows mainly ozone reductions with the largest reduction in the Denver and SLC areas but ozone increases in the Piceance Basin (Garfield County) for the 2021 High Scenario (Figure 5-1a) that is not seen for the Low Scenario (Figure 5-1b), but is seen in the Medium Development Scenario (Figure 5-1c). Although the largest ozone increase in both 2021

scenarios occurs near downtown Denver and is due to less fresh NO_x emissions that suppress urban ozone concentrations.

The 2021 High Development Scenario UAA ozone DVF without Source Group R (Federal O&G and mining in 13 CO BLM Planning Areas) results in reduction in the DVFs with the highest reduction of 6.4 ppb in the Piceance Basin and the peak DVF being reduced from 79.3 to 78.4 ppb that occurs just northwest of Denver (Figure 5-2a, top panels). In contrast, the removal of Source Group R from the 2021 Low Development Scenario results in smaller ozone reductions mainly in the Piceance Basin with a maximum reduction of 2.8 ppb (Figure 5-3a, top panels). The removal of Source Group R from the 2021 Medium Development Scenario reduces the maximum 2021 DVF from 79.2 to 78.5 ppb with a maximum DVF reduction of 5.6 ppb that occurs in the Piceance Basin (Figure 5-4a). There are still areas in Denver and SLC with 2021 DVFs exceeding the NAAQS with Source Group R removed.

Removing both Federal O&G and mining and non-Federal O&G (Source Group S) results in more reductions in the 2021 DVFs, especially in Weld County in the greater Denver area (Figures 5-2a, 5-3a and 5-4a, bottom panels). There are large reductions in 2021 DVFs in the Piceance and D-J Basins (Weld County) with the largest reduction being 12.8 ppb (High Scenario), 8.5 ppb (Low Scenario) and 12.2 ppb (Medium Scenario) in the Piceance Basin. There are no longer any ozone exceedances in the greater Denver area without emissions from Source Group S. The peak 2021 DVF is now ~77 ppb in the SLC area.

Source Group T adds the new O&G within the Mancos Shale development area to Source Group S (Figures 5-2b, 5-3b and 5-4b, top panels) and results in nearly identical 2021 DVFs as Source Group S in Colorado only with more ozone reductions in northwestern New Mexico.

When all O&G emissions are removed from the 2021 High and Low Development Scenarios in Source Group U, there are widespread reductions in the 2021 ozone DVFs throughout Colorado and spreading into Utah and New Mexico. Large ozone reductions occur in the D-J Basin (Weld County), Piceance Basin, Uinta Basin and South San Juan Basin; the single grid cell with the highest ozone reduction in the High (-18.8 ppb), Low (-16.1 ppb) and Medium (-18.4 ppb) occurs in the Piceance Basin (Figures 5-2b, 5-3b and 5-3c, bottom panels).

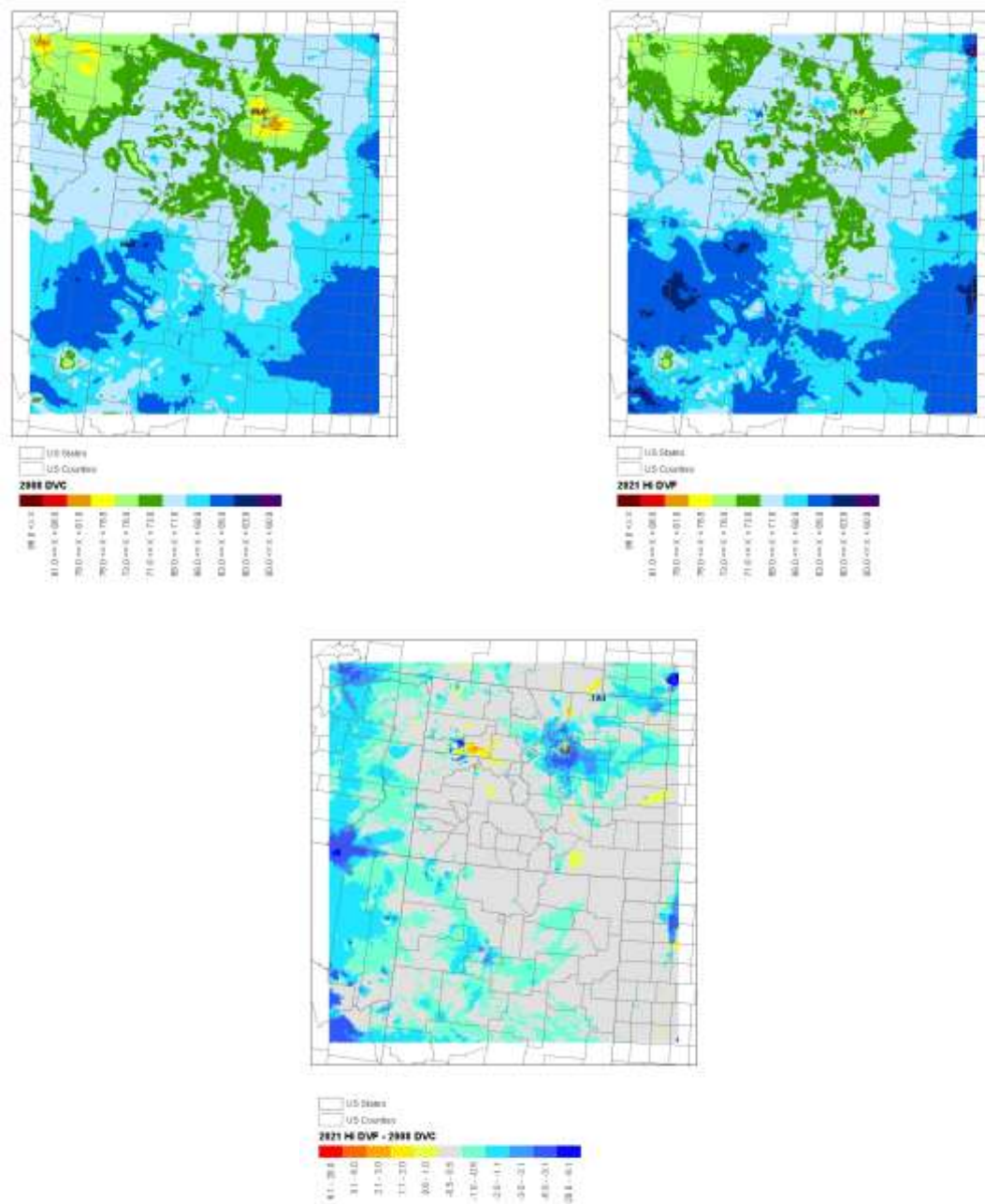


Figure 5-1a. 2008 ozone DVC (top left), 2021 High Development Scenario ozone DVF (top right) and their differences (2021 High – 2008) (bottom) calculated using MATS.

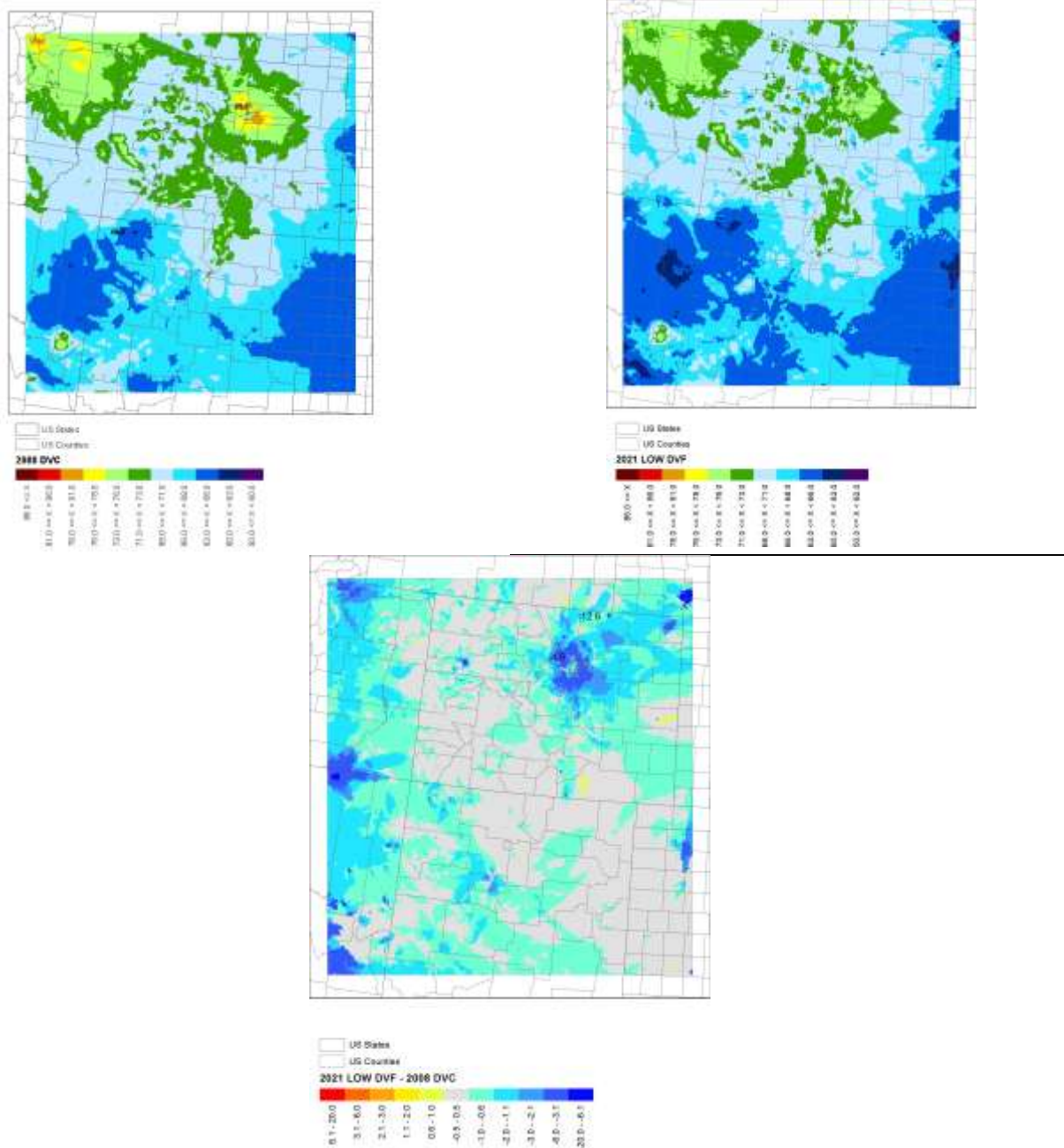


Figure 5-1b. 2008 ozone DVC (top left), 2021 Low Development Scenario ozone DVF (top right) and their differences (2021 Low – 2008) (bottom) calculated using MATS.

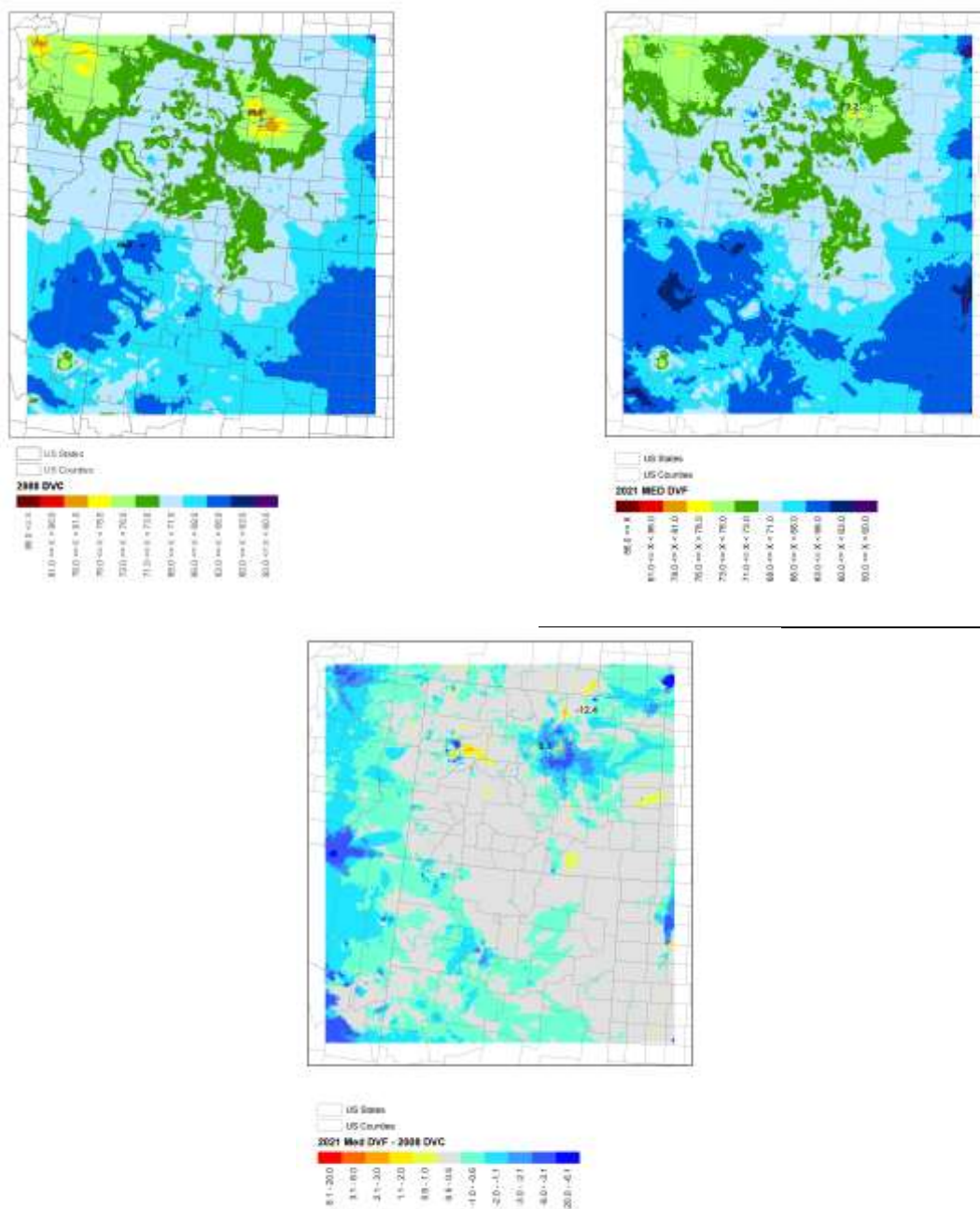


Figure 5-1c. 2008 ozone DVC (top left), 2021 Medium Development Scenario ozone DVF (top right) and their differences (2021 Medium – 2008) (bottom) calculated using MATS.

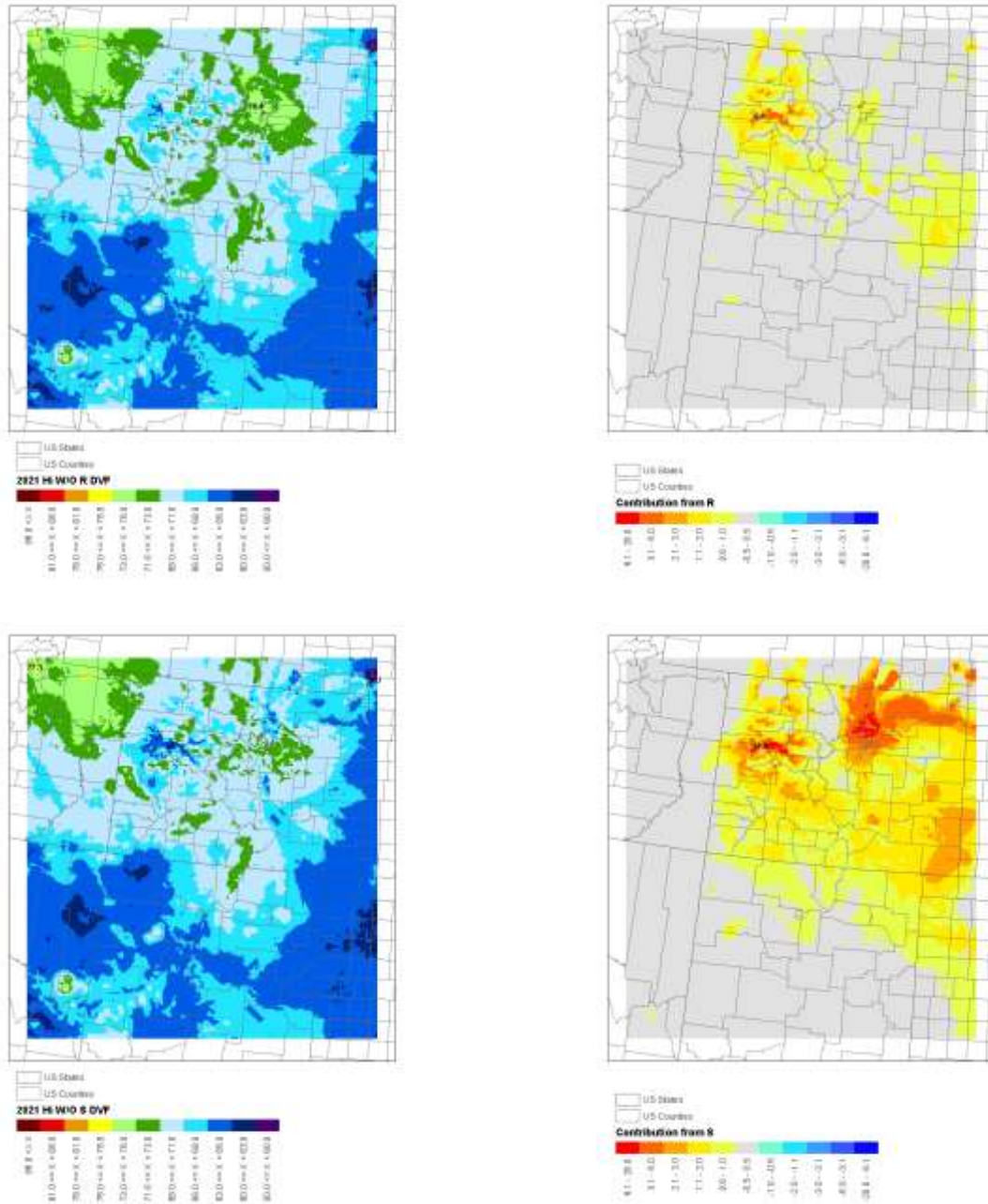


Figure 5-2a. 2021 projected ozone DVF 2021 Unmonitored Area Analysis for Source Group R (top) and S (bottom) showing 2021 DVF without each Source Group (left) and difference in DVFs with 2021 High Development Scenario (right).

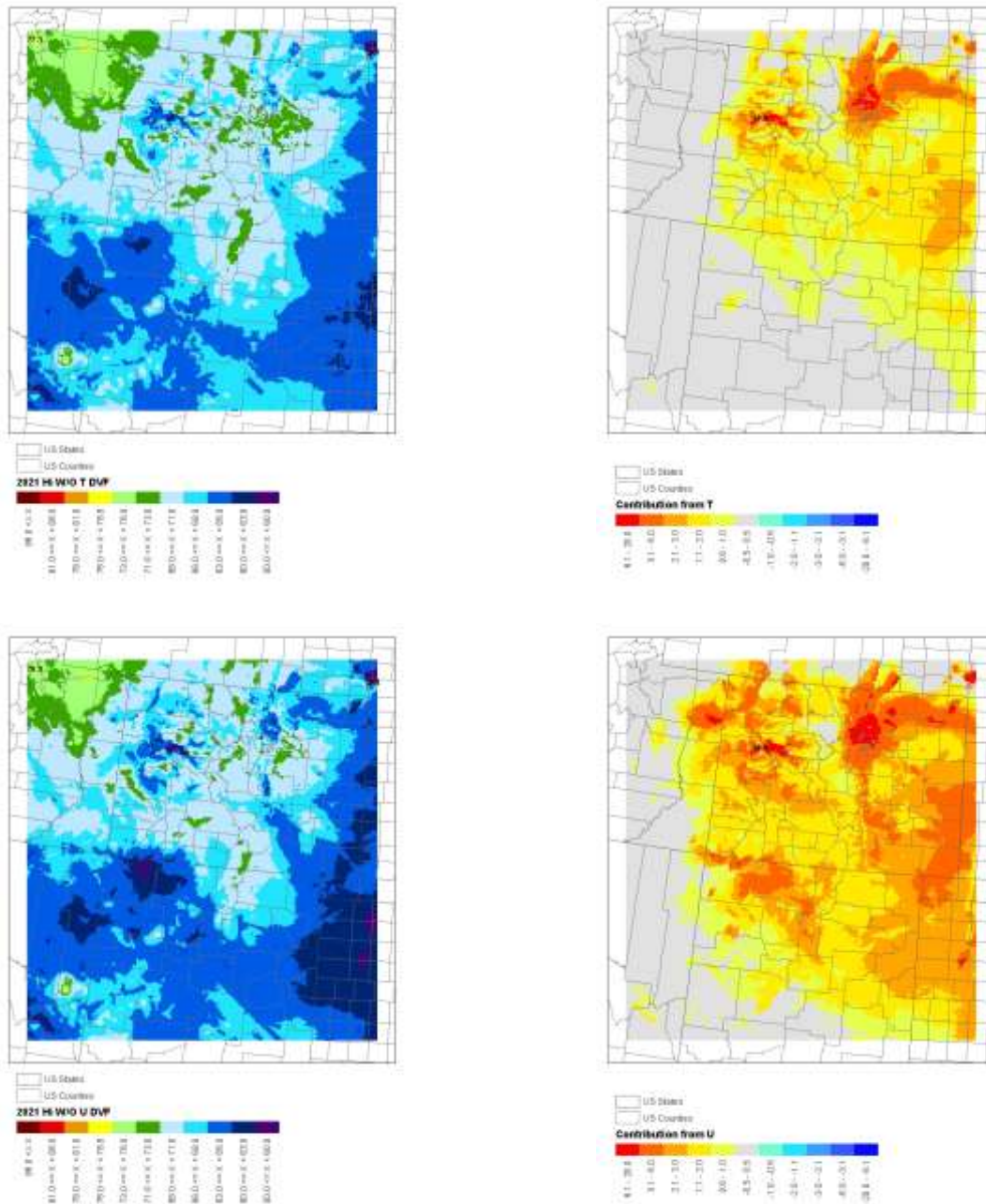


Figure 5-2b. 2021 projected ozone DVF 2021 Unmonitored Area Analysis for Source Group T (top) and U (bottom) showing 2021 DVF without each Source Group (left) and difference in DVFs with 2021 High Development Scenario (right).

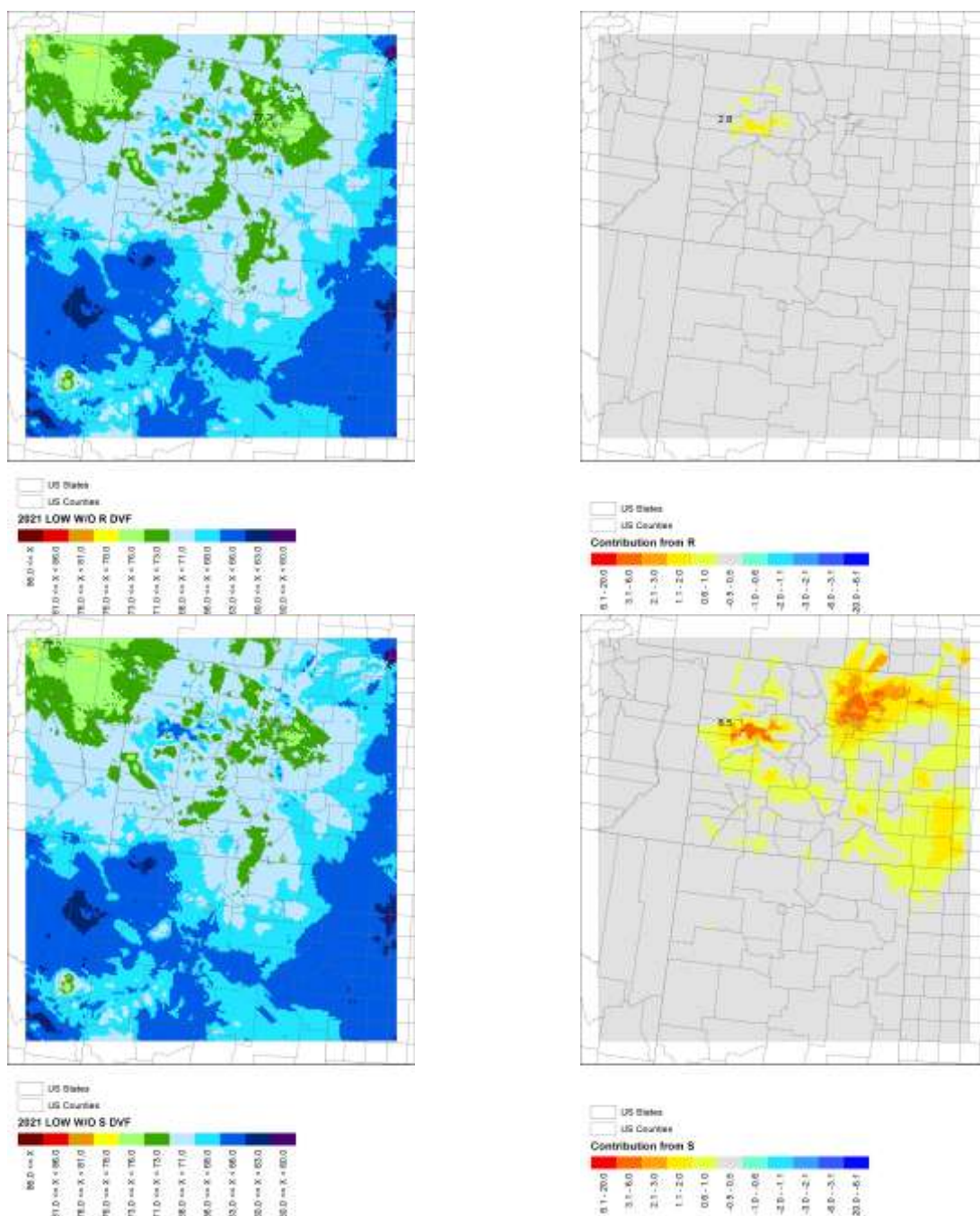


Figure 5-3a. 2021 projected ozone DVF 2021 Unmonitored Area Analysis for Source Group R (top) and S (bottom) showing 2021 DVF without each Source Group (left) and difference in DVFs with 2021 Low Development Scenario (right).

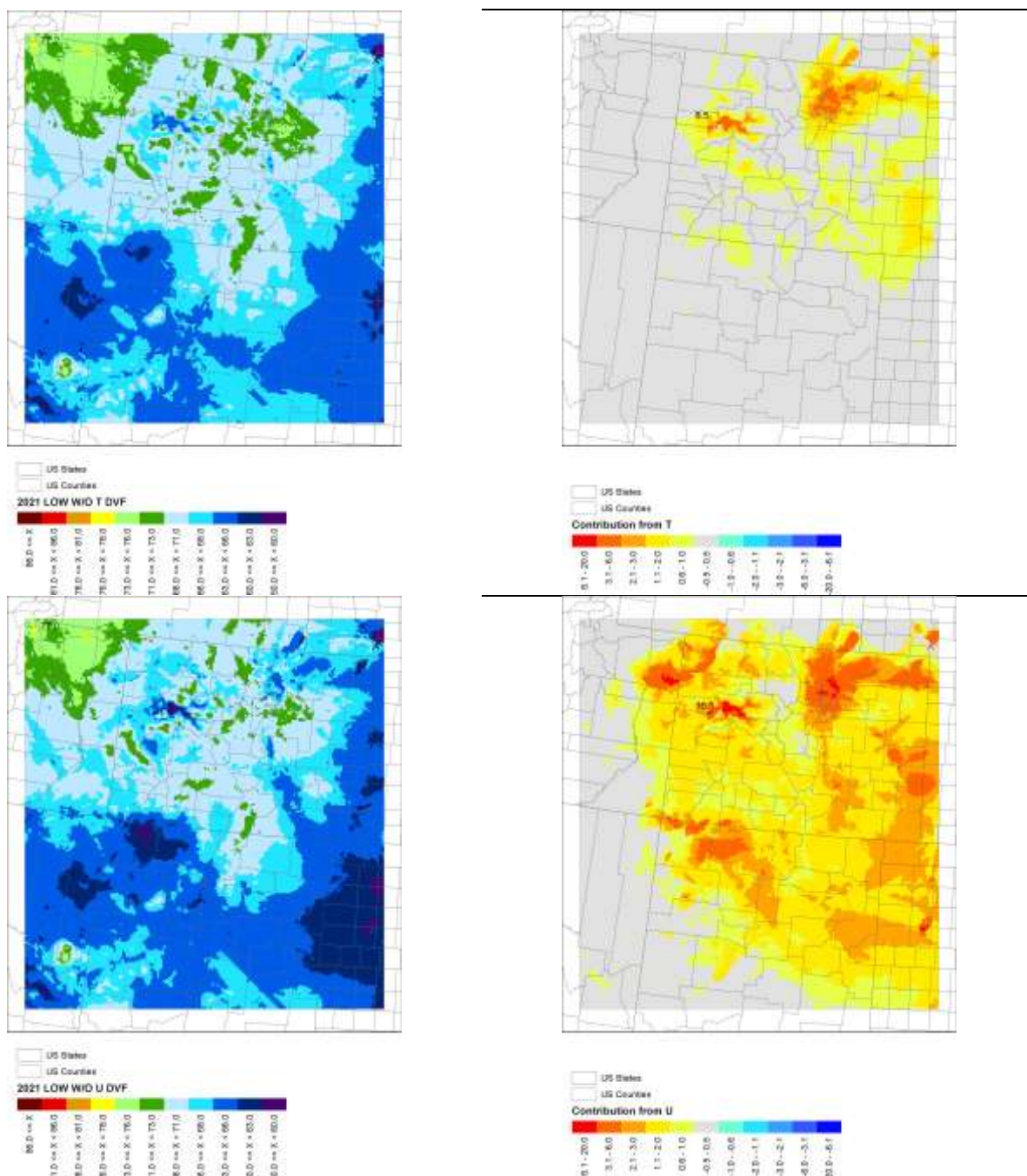


Figure 5-3b. 2021 projected ozone DVF 2021 Unmonitored Area Analysis for Source Group T (top) and U (bottom) showing 2021 DVF without each Source Group (left) and difference in DVFs with 2021 Low Development Scenario (right).

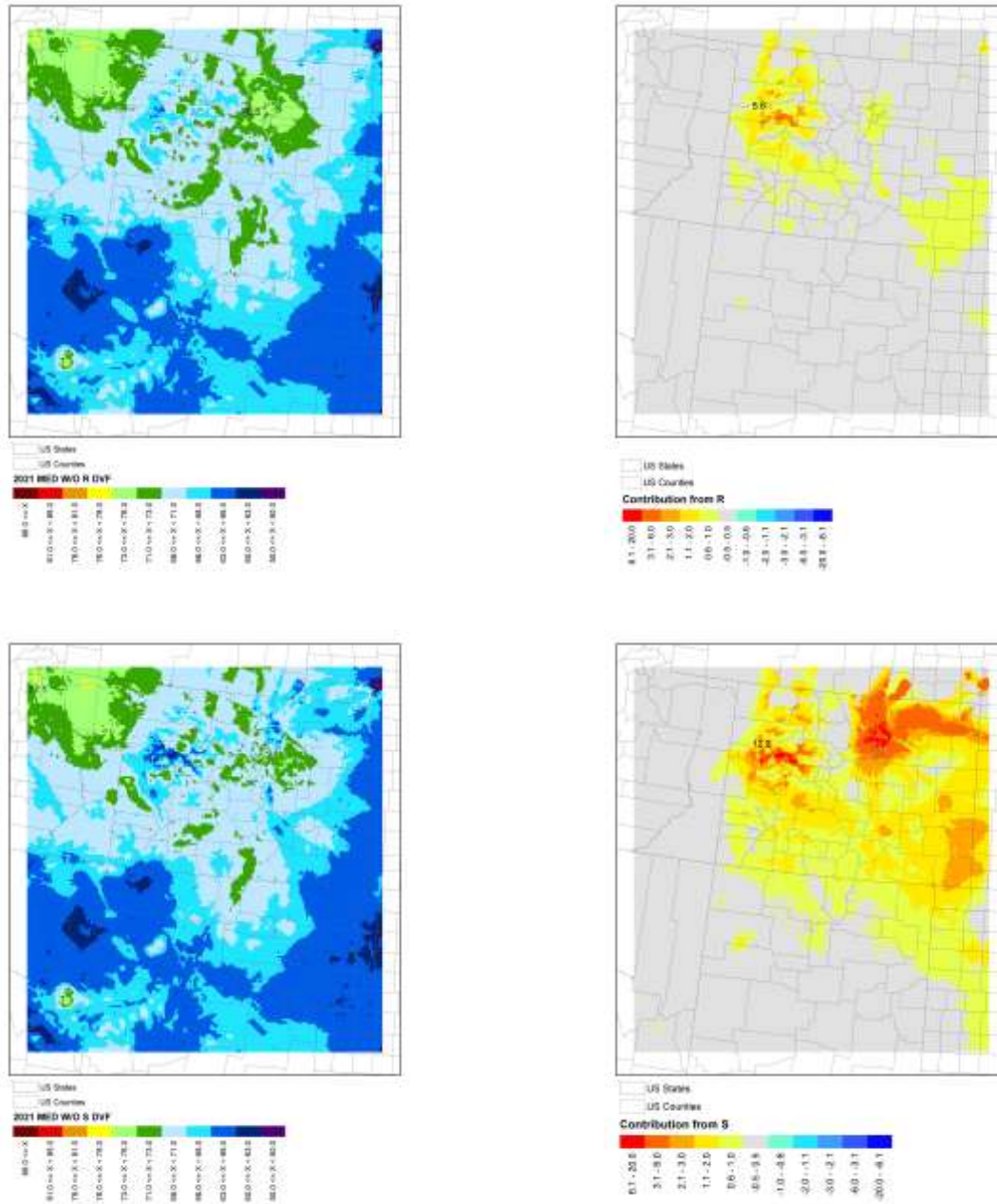


Figure 5-4a. 2021 projected ozone DVF 2021 Unmonitored Area Analysis for Source Group R (top) and S (bottom) showing 2021 DVF without each Source Group (left) and difference in DVFs with 2021 Medium Development Scenario (right).

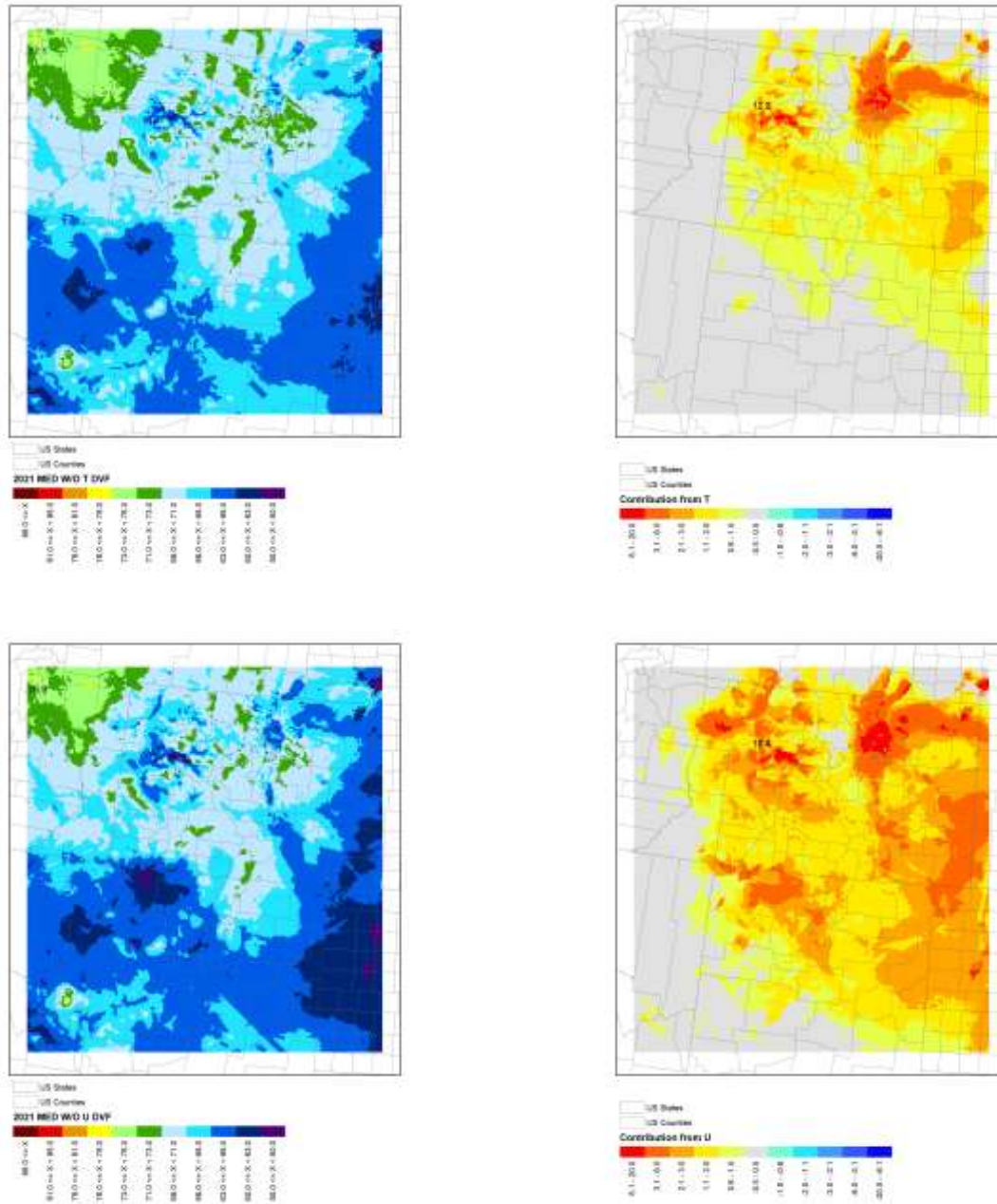


Figure 5-4b. 2021 projected ozone DVF 2021 Unmonitored Area Analysis for Source Group T (top) and U (bottom) showing 2021 DVF without each Source Group (left) and difference in DVFs with 2021 Medium Development Scenario (right).

5.6.2 Ozone NAAQS Analysis using the Absolute Modeling Results

The 2021 High and Low Development Scenario CAMx source apportionment absolute modeling results are analyzed and compared to the NAAQS in this section. The ozone NAAQS is defined as the three-year average of the 4th highest daily maximum 8-hour (DMAX8) ozone concentration. Since CARMMS only uses one year of modeling results (2008 meteorological year), the 2021 4th highest DMAX8 ozone concentration is used as a pseudo-NAAQS comparison metric. The contributions of each Source Group to ozone is examined as the difference between the 4th highest DMAX8 ozone concentration for the 2021 emissions scenario minus the 4th highest DMAX8 ozone for the 2021 scenario with the Source Group contributions removed. In addition, the contributions of each Source Group to modeled 2021 4th high DMAX8 ozone greater than the NAAQS (i.e., 76.0 ppb or greater) is also analyzed.

5.6.2.1 Contributions of Source Groups to 4th High DMAX8 Ozone

Figure 5-5 displays the 4th highest DMAX8 ozone for the 2008 Base Case and the 2021 High, Low and Medium Development Scenarios and their differences and the 4th highest DMAX8 ozone for the 2021 scenario with the ozone contributions from natural emissions removed (Source Group V). This last display was generated to determine whether exceedances of the NAAQS could have been primarily due to natural emissions. The color scale in Figure 5-5 has a sharp contrast from dark red to white when an exceedance of the ozone NAAQS occurs (i.e., 76.0 ppb or higher). For the 2008 Base Case, there are several regions where the modeled 2021 4th high DMAX8 ozone exceeds the NAAQS (Figure 5-5, top left):

- The Denver area;
- Uinta Basin and Salt Lake City (SLC), Utah;
- Northern New Mexico northeast of Santa Fe;
- Northern New Mexico northeast of Los Alamos;
- Northern New Mexico north of Taos; and
- On the UT/AZ border.

In the 2021 High, Low and Medium Development Scenarios, the area of ozone exceedances in Denver is reduced and the ozone exceedances in the SLC and UT/AZ border area are gone. However, the modeled ozone exceedance area in northern New Mexico remains the same and there is a new ozone exceedance area in the Uinta Basin in the three 2021 scenarios (Figure 5-5, top right). The 2021 – 2008 ozone differences (Figure 5-5, bottom left) show more decreases than increases and the areas of ozone increases tend to occur in O&G development areas, such as the D-J, Piceance and Uinta Basins. The contribution of natural emissions to the modeled 4th highest daily maximum 8-hour ozone concentrations (Figure 5-5, bottom right) show that the ozone exceedance areas in northern New Mexico are due to natural emissions, most likely wildfires.

Attachment I is a zipped file that contains spatial maps of concentrations including total concentrations and the contributions of each of the Source Groups to the 4th highest DMAX8 ozone and other pollutants from the 2021 High, Low and Medium Development Scenarios CAMx source apportionment modeling. Figure 5-6 displays example spatial maps of contributions to the 4th highest DMAX8 ozone concentrations for Source Groups E (GJFO), F (UFO), J (USFS-PG), R (Federal O&G/mining in CO) T (Cumulative Emissions Scenario) and U (all O&G in 4 km CARMMS domain) and the 2021 High, Low and Medium Development Scenarios that were extracted out of Attachment I. The maximum ozone contributions to the 4th highest DMAX8 ozone for each of the Source Groups are given in Table 5-40. Note that these maximum Source Group contributions to the 4th highest DMAX8 ozone occur when the total ozone is less than the ozone NAAQS. Section 5.6.2.2 discusses the Source Group contributions when the total 4th high DMAX8 ozone exceeds the ozone NAAQS. Ozone contributions due to Federal O&G development in the GJFO Planning Area are centered on the GJFO area where a maximum ozone contribution of 4.4 ppb occurs for the 2021 High Development Scenario (Table 5-40 and Figure 5-6a, top left). The mitigation in the 2021 Medium Development Scenario reduces this maximum GJFO ozone contribution by -18% to 3.6 ppb. There is much lower 4th high DMAX8 ozone contributions due to GJFO for the 2021 Low Development Scenario (Figure 5-6a, top right) with a maximum contribution of only 0.8 ppb (Table 5-40).

Lower 4th high DMAX8 ozone contributions are seen for UFO new Federal O&G with highest ozone contributions of 0.8, 0.2 and 0.6 ppb for the, respectively, 2021 High, Low and Medium Development Scenarios occurring in the northeast corner of the UFO Planning Area (Figure 5-6b). Even smaller ozone contributions still are seen due to new Federal O&G within the USFS-PG area with a maximum values of 0.5, 0.1 and 0.3 ppb for the 2021 High, Low and Medium Development Scenarios, respectively (Figure 5-6c).

The maximum ozone contribution due to Federal O&G and mining throughout the 13 CO Planning areas for the 2021 High, Low and Medium Development Scenarios are, respectively, 7.9, 2.8 and 6.1 ppb and occur in the Piceance Basin (Table 5-40 and Figure 5-6d). There are several areas with ozone contributions of 3 ppb or more for the 2021 High and Medium Development Scenarios and the Cumulative Emissions Source Group T (new Federal and non-Federal O&G and mining in the 14 BLM Planning Areas), including the Piceance and D-J Basins but also in southeastern Colorado (RGFO area No. 2) as shown in the top left and bottom panels of Figure 5-6e. Substantial ozone reductions are seen in the 2021 Low Development Scenario (Figure 5-6e, top right) with the highest ozone being reduced from 8.4 and 7.0 ppb in the High and Medium scenarios to 4.4 ppb in the Low Development Scenario.

Figure 5-6f displays the reduction in 4th highest DMAX8 ozone concentrations due to the elimination of all O&G in the 4 km CARMMS domain. All of the major O&G Basins exhibit reductions in ozone in excess of 3 ppb in the 2021 High and Medium Development Scenarios with the highest ozone reduction occurring in the Uinta Basin of 9.4 ppb for both the High and Medium Development scenarios and 9.2 ppb for the Low Development Scenario. Note that the same O&G emissions were used in the Uinta Basin for the three CARMMS 2021 Scenarios that came from the BLM UTSO ARMS study, which explains why there is little difference in the peak ozone contribution for the three scenarios.

Table 5-40. Maximum contribution to the 4th highest DMAX8 ozone (ppb) for each of the Source Groups and the 2021 High, Low and Medium Development Scenarios.

Source Group	High	Low	Medium
A. Little Snake FO	1.0	0.3	1.0
B. White River FO	3.9	1.2	3.6
C. Colorado River Valley FO (w/o Roan Plateau)	2.6	1.5	2.3
D. Roan Plateau	3.8	1.7	3.3
E. Grand Junction FO	4.4	0.8	3.6
F. Uncompahgre FO	0.8	0.2	0.6
G. Tres Rios FO	1.4	0.4	1.4
H. Kremmling FO	0.5	0.1	0.5
I. Royal Gorge FO No. 1 (North)	0.1	0.0	0.1
J. Pawnee Grasslands	0.5	0.1	0.3
K. Royal Gorge FO No. 2	0.9	0.1	0.7
L. Royal Gorge FO No. 3	0.2	0.1	0.2
M. Royal Gorge FO No. 4	0.1	0.0	0.1
N. New Mexico Farmington FO (Mancos)	1.1	0.8	0.8
O. Colorado River Valley FO (w/ Roan Plateau)	5.0	2.1	3.9
P. Royal Gorge FO (total)	0.9	0.1	0.7
Q. Federal Mining in Colorado	0.9	0.9	0.9
R. New Federal O&G and Mining In Colorado	7.9	2.8	6.1
S. New Federal/Non-Federal O&G/Mining in CO	8.4	4.4	7.0
T. New Federal/Non-Federal O&G/Mining in CO/NM	8.4	4.4	7.0
U. Existing and New Fed/Non-Fed O&G in 4 km Domain	9.4	9.2	9.4
V. Natural Emissions	5.6	5.7	5.6

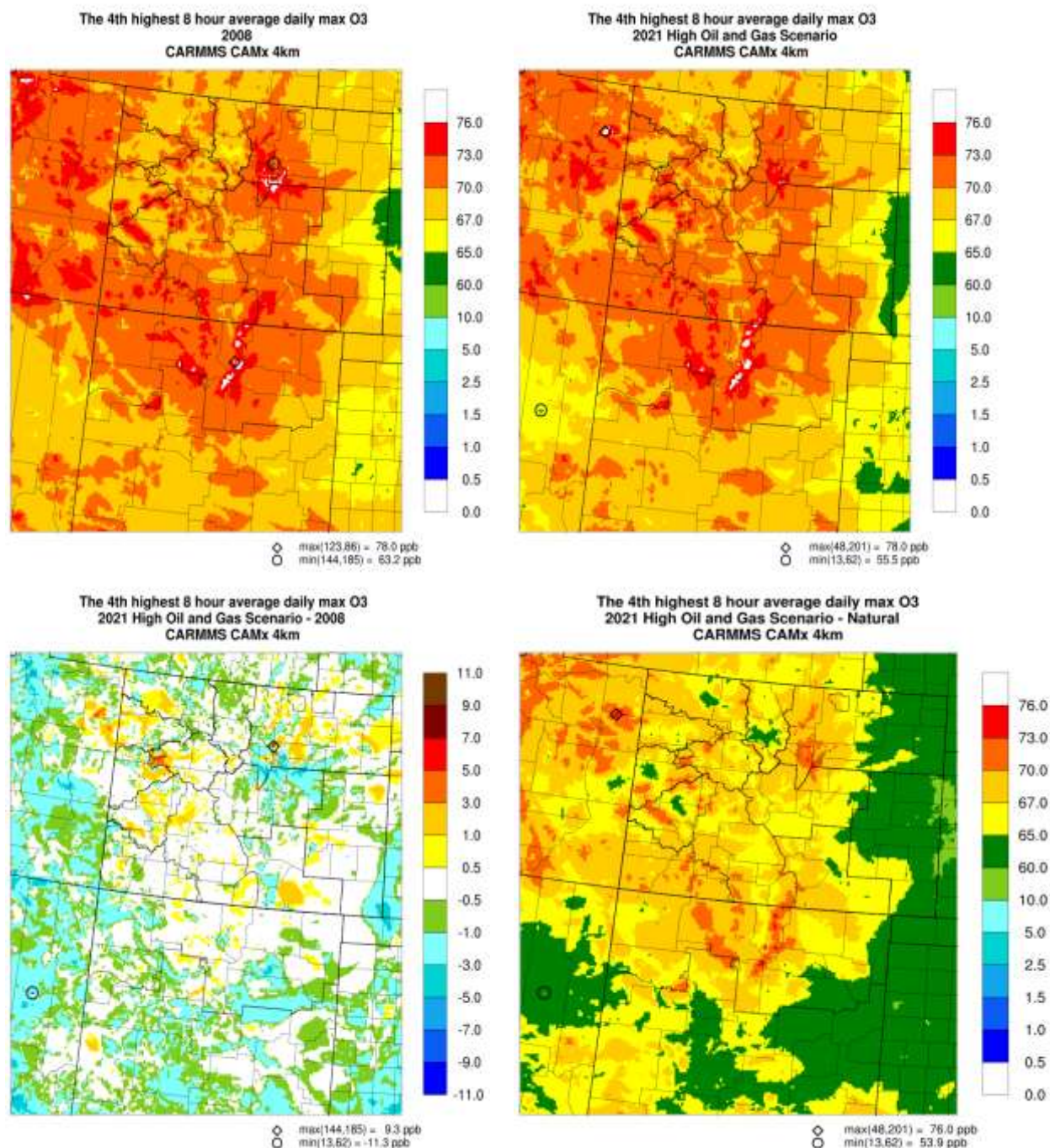


Figure 5-5a. Fourth highest daily maximum 8-hour ozone concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 High minus 2008 differences (bottom left) and Natural Emissions (bottom right).

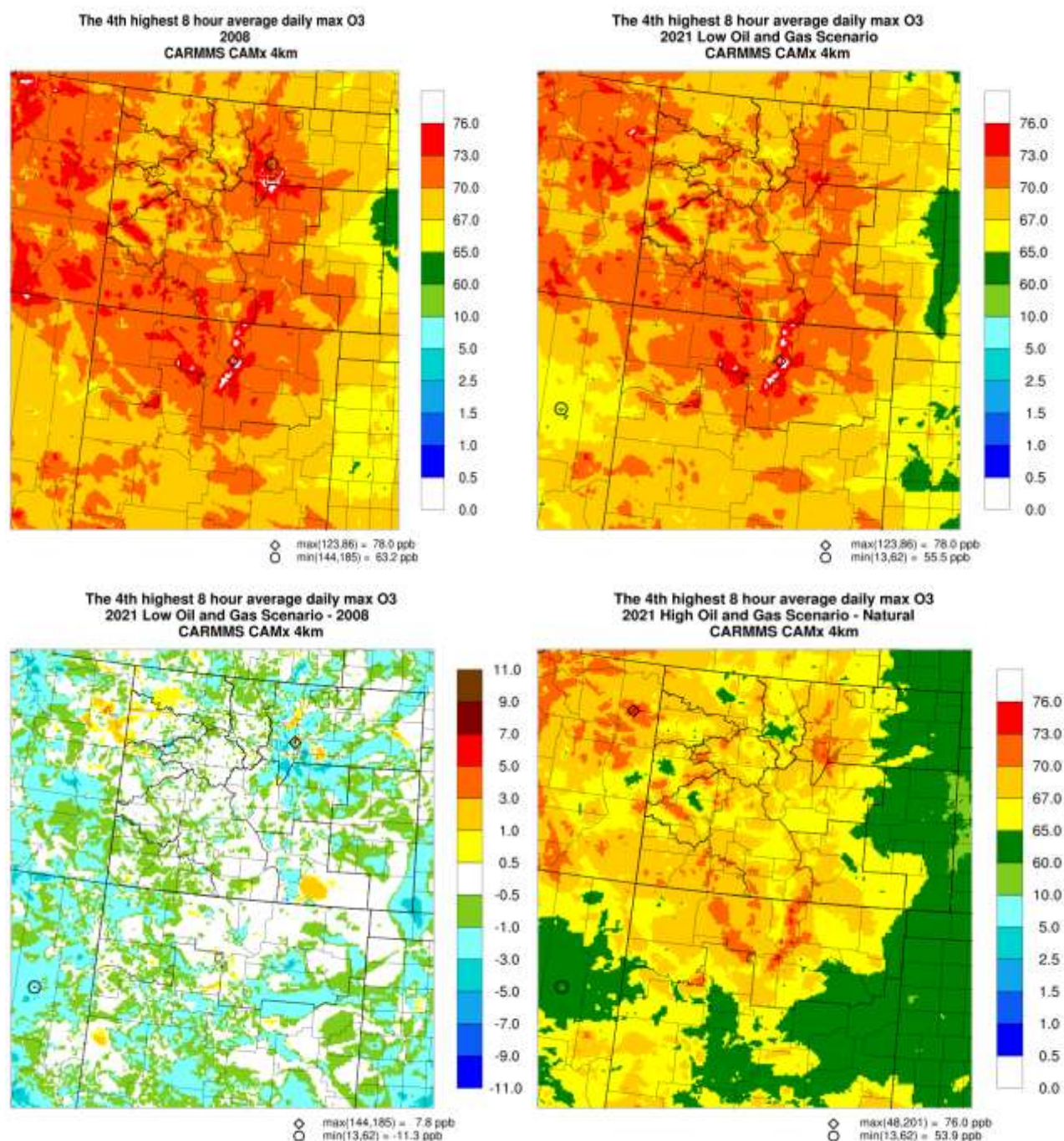


Figure 5-5b. Fourth highest daily maximum 8-hour ozone concentrations for the 2008 Base Case (top left), 2021 Low Development Scenario (top right), 2021 Low minus 2008 differences (bottom left) and Natural Emissions (bottom right).

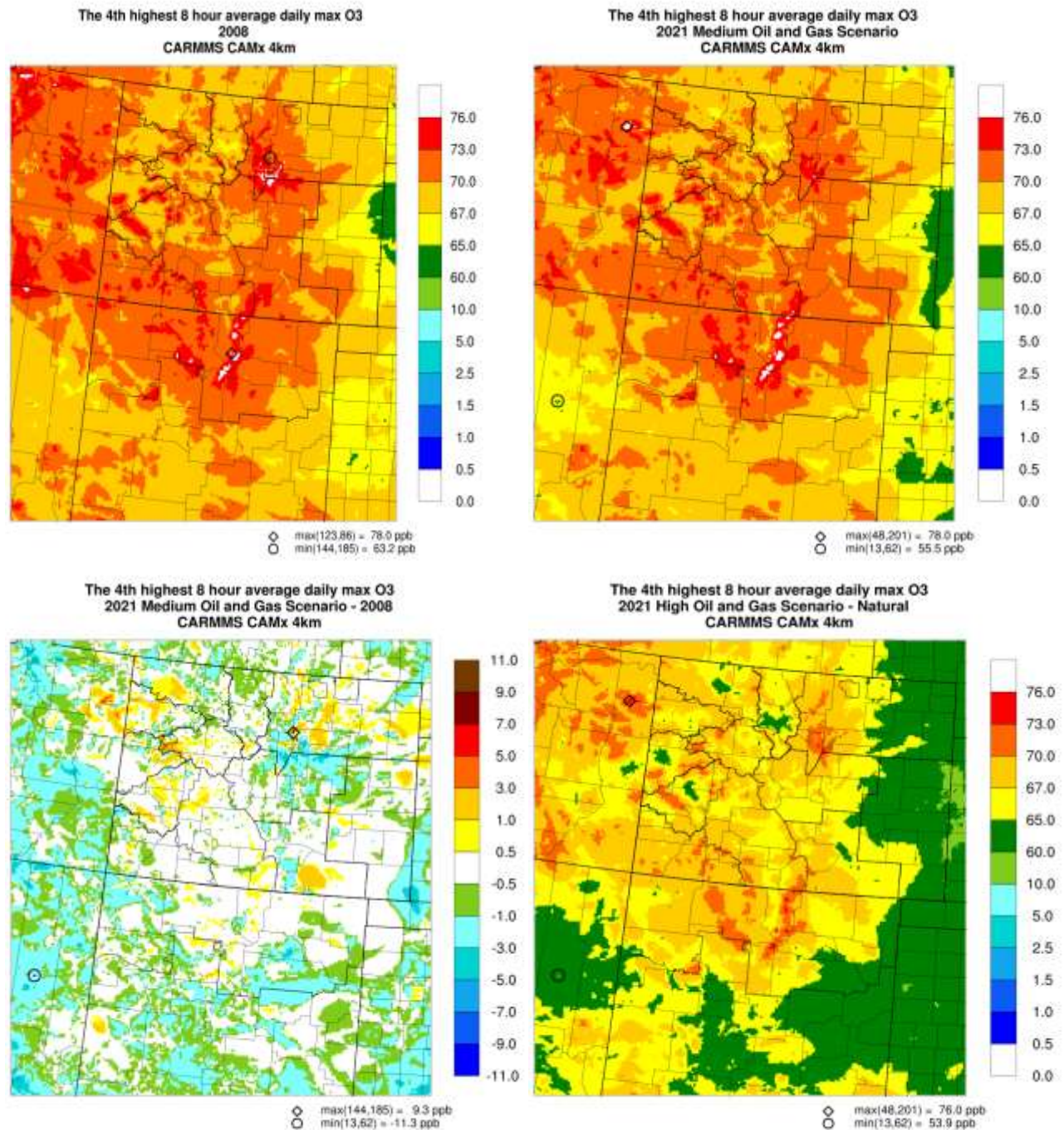


Figure 5-5c. Fourth highest daily maximum 8-hour ozone concentrations for the 2008 Base Case (top left), 2021 Medium Development Scenario (top right), 2021 Medium minus 2008 differences (bottom left) and Natural Emissions (bottom right).

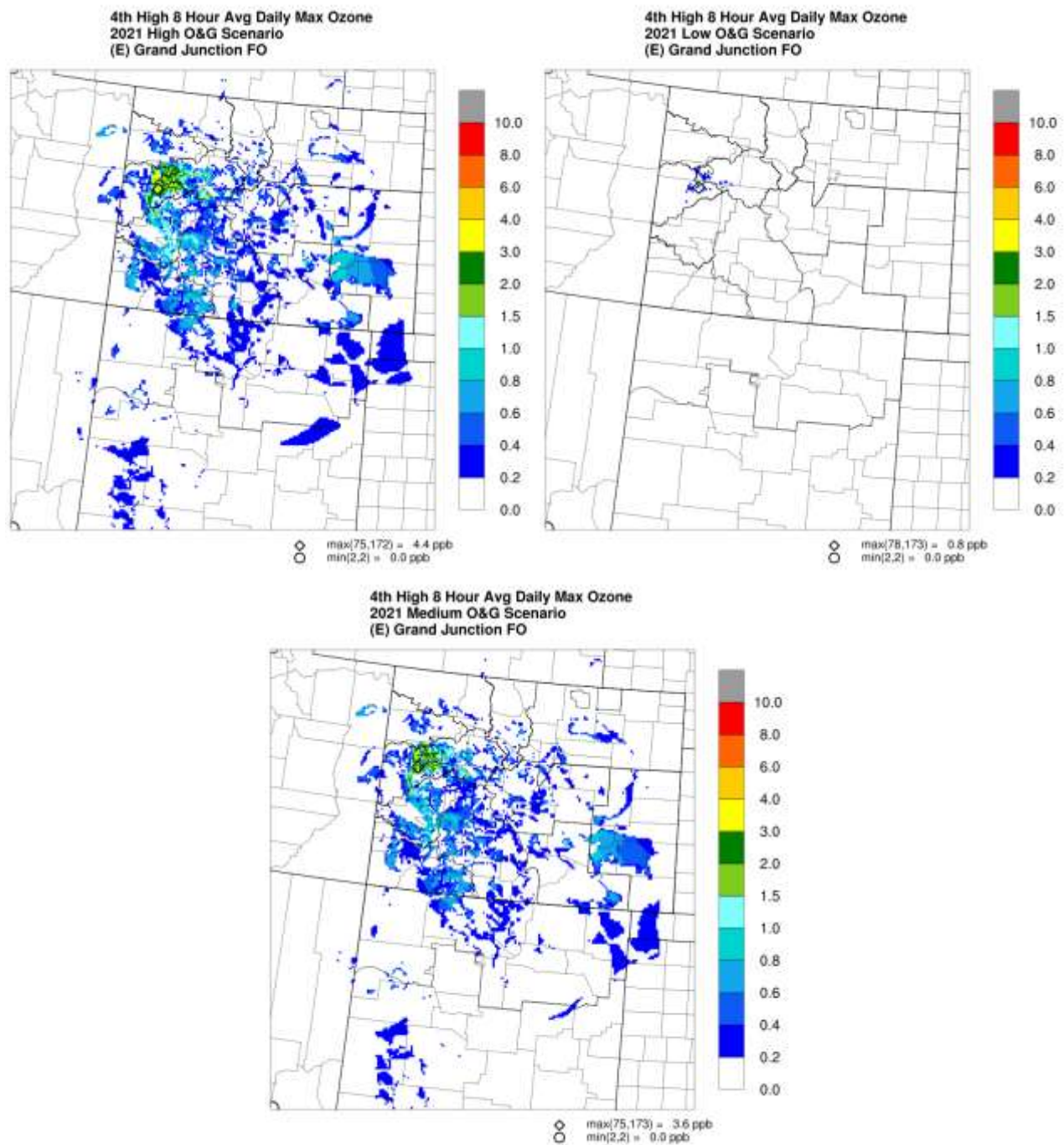


Figure 5-6a. Contributions to fourth highest daily maximum 8-hour ozone due to emissions from new Federal O&G within the GJFO (Source Group E) for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

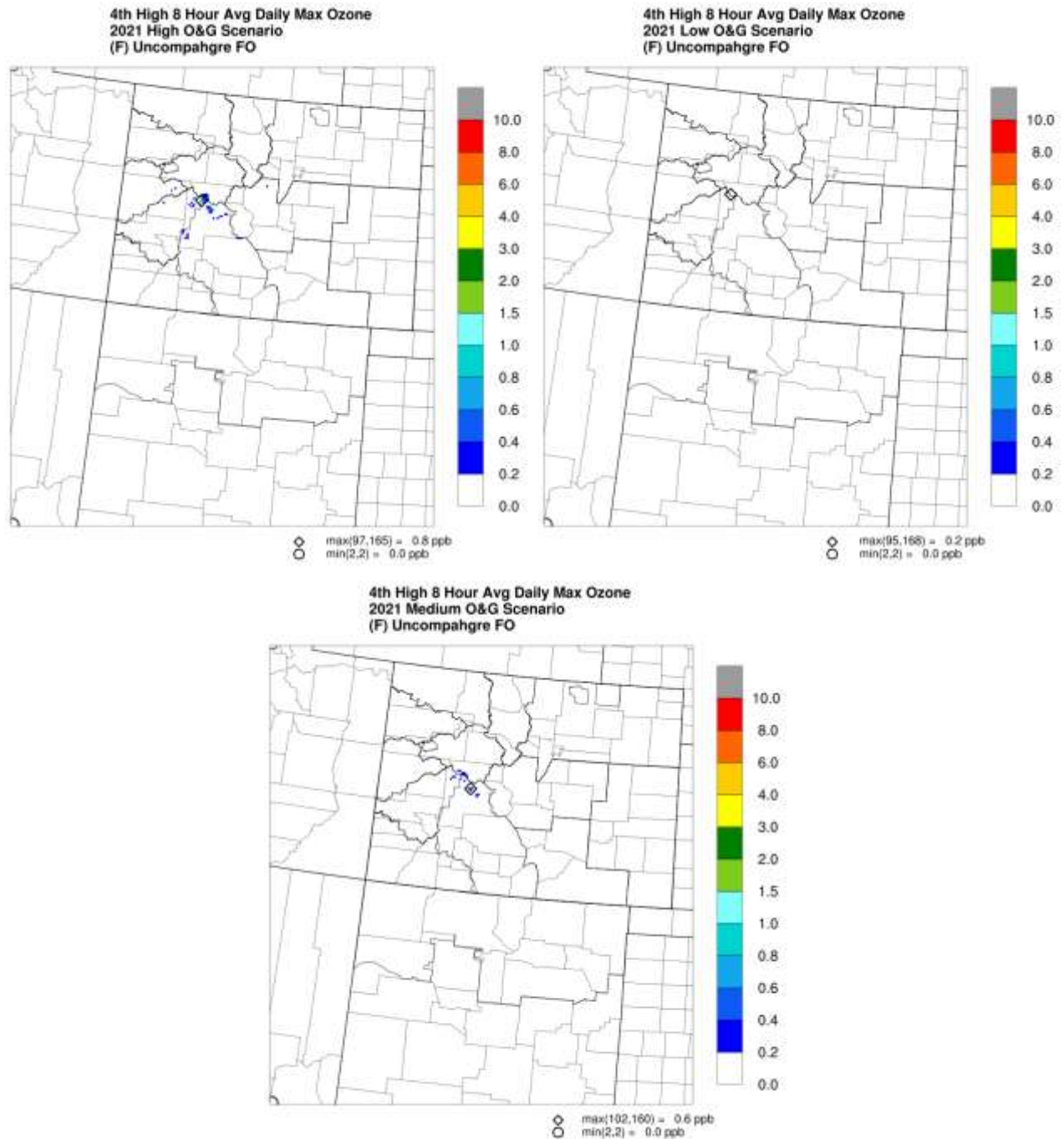


Figure 5-6b. Contributions to fourth highest daily maximum 8-hour ozone due to emissions from new Federal O&G within the UFO (Source Group F) for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

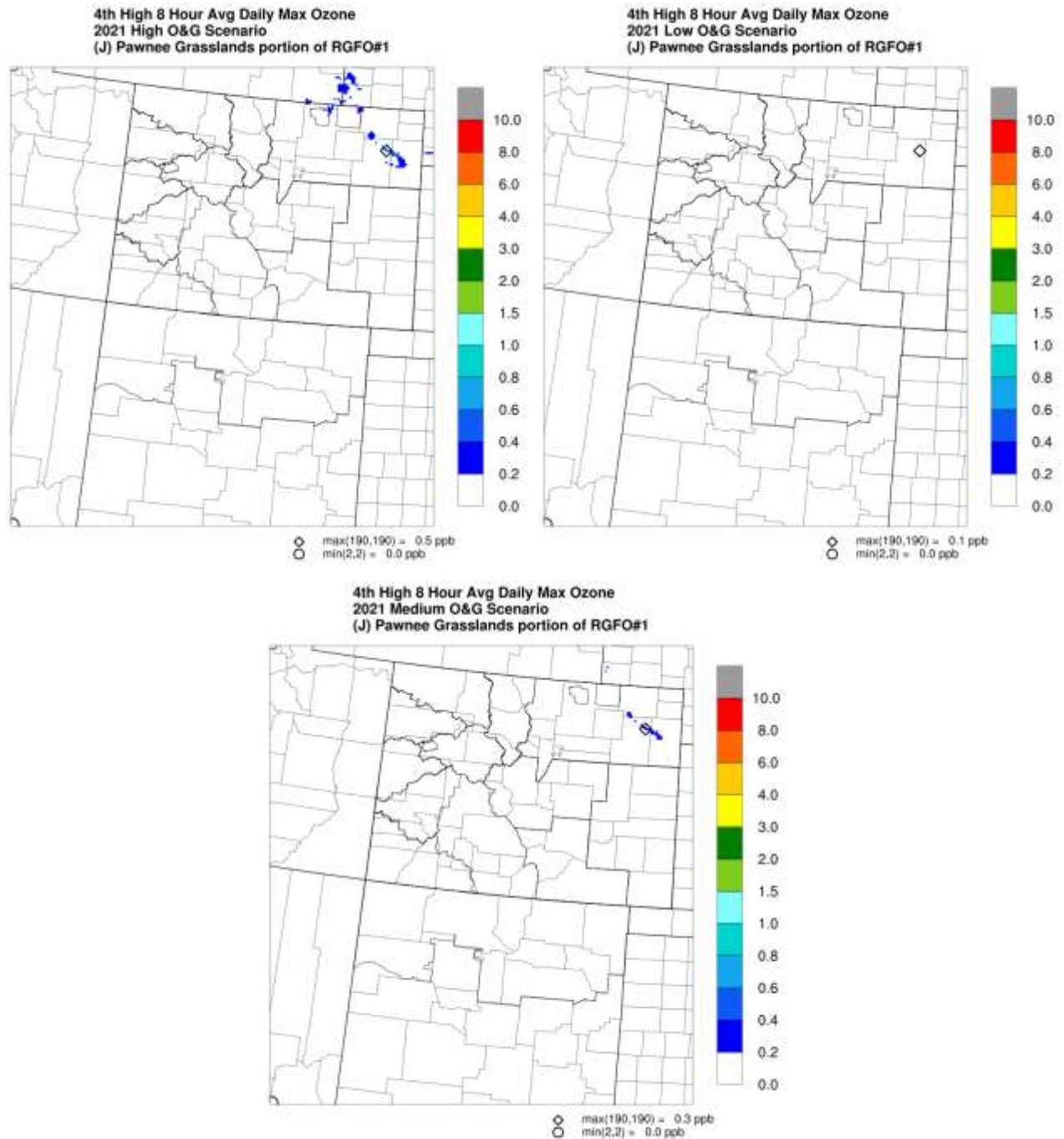


Figure 5-6c. Contributions to fourth highest daily maximum 8-hour ozone due to emissions from new Federal O&G within the USFS Pawnee Grasslands (Source Group J) for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

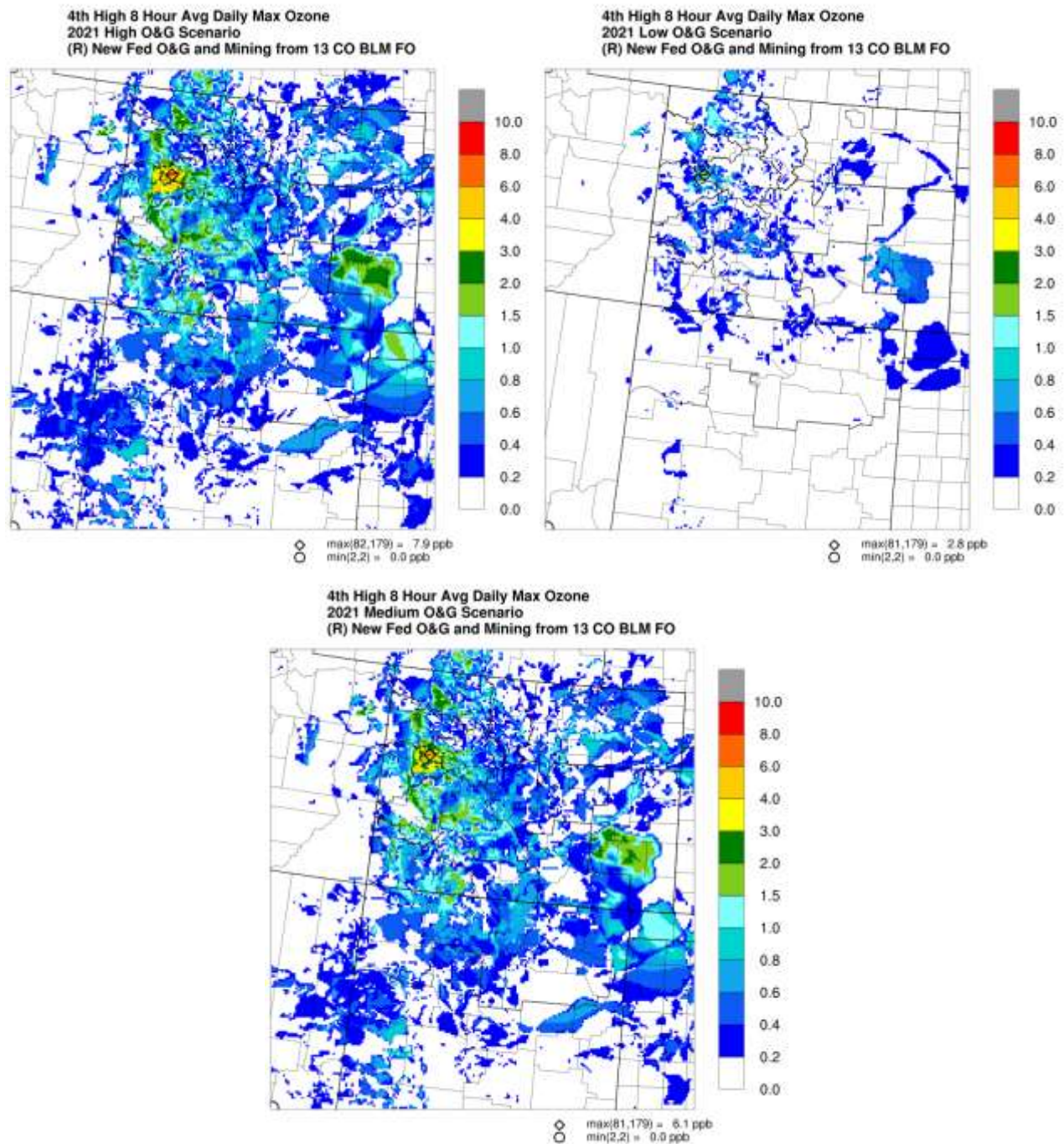


Figure 5-6d. Contributions to fourth highest daily maximum 8-hour ozone due to emissions from new Federal O&G and mining within the 13 Colorado BLM Planning Areas (Source Group R) for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

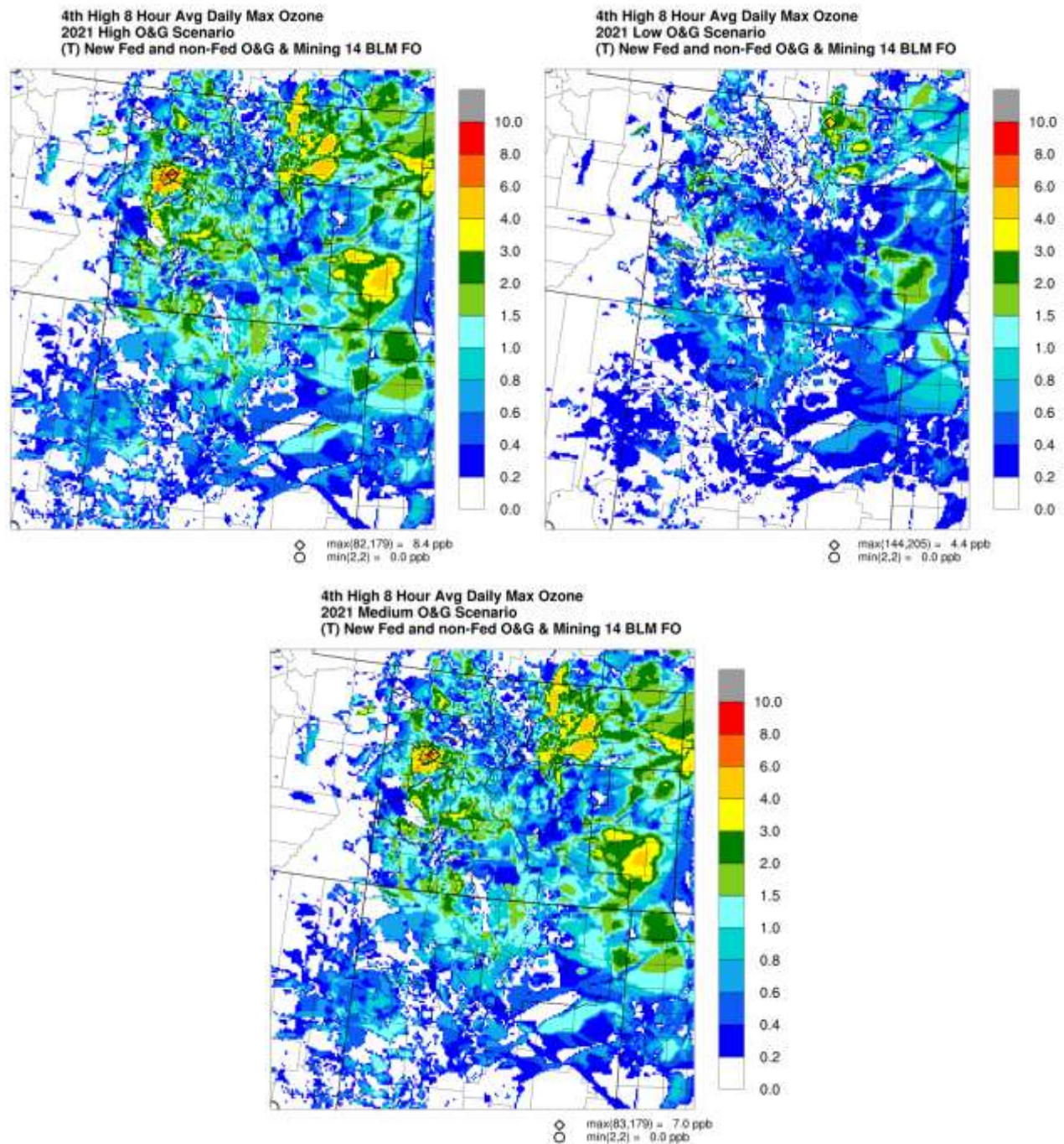


Figure 5-6e. Contributions to fourth highest daily maximum 8-hour ozone due to emissions from new Federal and non-Federal O&G and mining within the 14 CO/NM BLM Planning Areas (Source Group T) for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

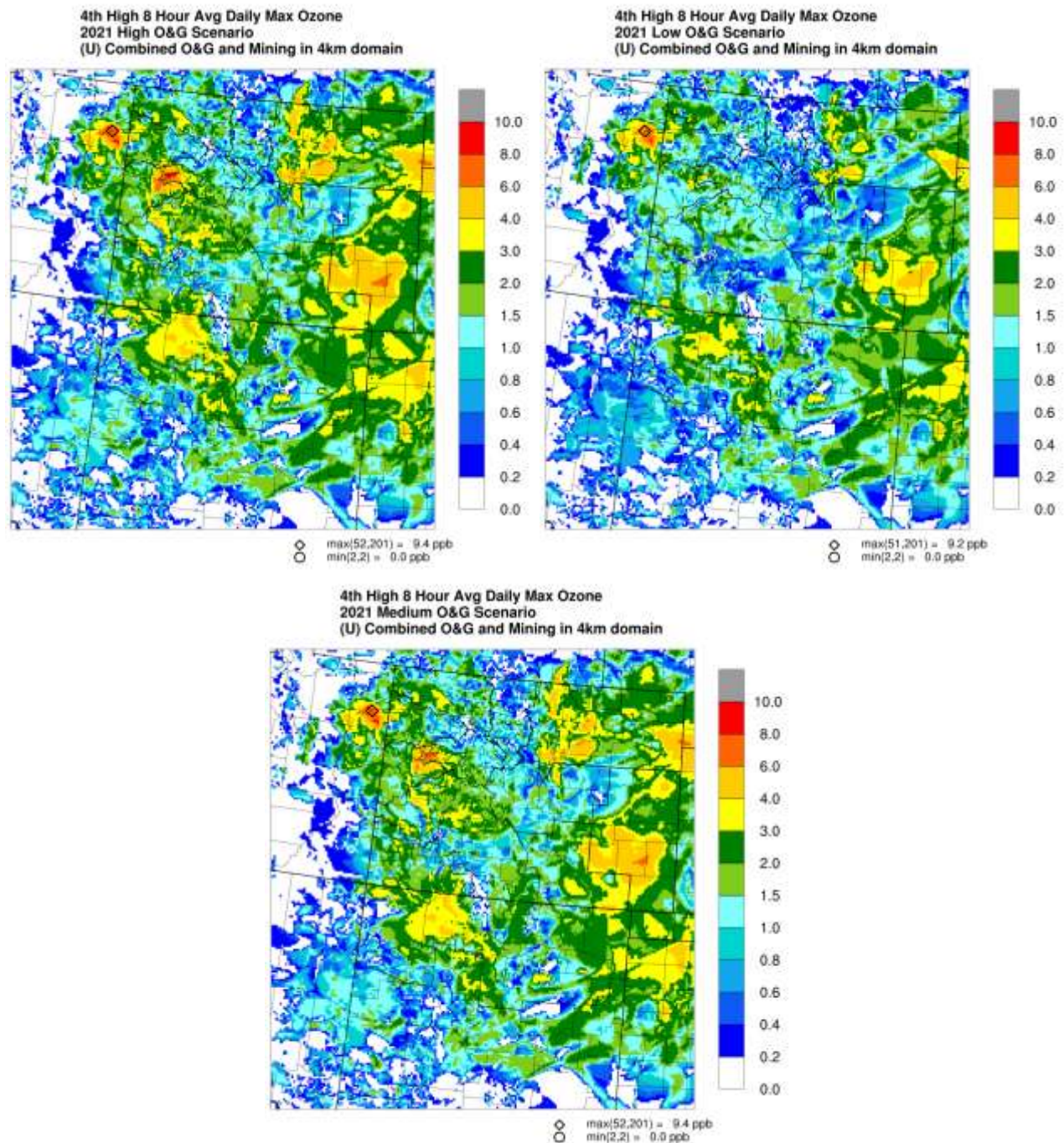


Figure 5-6f. Contributions to fourth highest daily maximum 8-hour ozone due to emissions from existing, new Federal and non-Federal O&G within the entire CARMMS 4 km domain and Federal mining in Colorado (Source Group U) for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

5.6.2.2 Source Group Absolute Contributions to Ozone Exceedances

The contributions of each Source Group to 4th highest DMAX8 ozone above the current ozone NAAQS (76.0 ppb and higher) for the 2021 High, Low and Medium Development Scenarios are contained in Attachments G-1, G-2 and G-3, respectively. The Attachment G interactive Excel spreadsheet contains two sheets: “StatTable” that displays the maximum ozone contribution for each Source Group to modeled 2021 DMAX8 ozone greater than the NAAQS; and “Scatter_by_exceedance_region” that shows the ozone contribution of a Source Group, controlled by cell C1, to all grid cells with modeled 2021 4th high DMAX8 ozone greater than the NAAQS by region. Table 5-41 from StatTable in Attachment G lists the maximum ozone contribution to any modeled 2021 4th high DMAX8 ozone greater than the NAAQS. The WRFO is the individual BLM Planning Area with the largest contribution to 2021 modeled exceedances of the ozone NAAQS of 1.83 ppb for the High, 0.43 ppb for the Low and 1.66 ppb for the Medium Development Scenarios when the 2021 total ozone was 76.5, 77.0 and 76.3 ppb, respectively. All of the other individual BLM Planning Areas (Source Groups A through P) have maximum ozone contributions to modeled 2021 DMAX8 ozone in excess of the ozone NAAQS of less than 1 ppb for the 2021 High, Low and Medium Development Scenarios.

The highest contribution to 2021 DMAX8 ozone for all Federal O&G and mining within the 13 Colorado BLM Planning Areas (Source Group R) is 3.22, 0.86 and 2.84 ppb for the 2021 High, Low and Medium Development Scenarios, respectively. The contribution of new Federal and non-Federal O&G and Federal mining within the 14 BLM Planning Areas (Source Group T) to 2021 DMAX8 ozone exceedances are 5.32, 2.25 and 4.91 ppb for the High, Low and Medium Development Scenarios, respectively. The highest contribution of all O&G in the CARMMS domain to modeled 2021 DMAX8 ozone exceedances is 31.94, 30.73 and 31.79 ppb for the 2021 High, Low and Medium Development Scenarios that is primarily due to O&G emissions in the Uinta Basin.

Figure 5-7 displays the contribution of Federal O&G emissions from the GJFO BLM Planning Area to the 2021 4th high DMAX8 ozone at all grid cells in the domain that came from the “Scatter_by_exceedance_region” sheet in Attachments G-1, G-2 and G-3. GJFO has the highest contribution to ozone exceedances in the Uinta Basin with contributions of ~0.70, ~0.06 and ~0.60 ppb for the 2021 High, Low and Medium Development Scenarios, respectively (Figure 5-7a, left). The contributions of new Federal O&G and mining within the 13 Colorado BLM Planning Areas (Source Group R) to exceedances of the ozone NAAQS is shown in the right panels in Figure 5-7a with the highest contributions of ~3.0, ~0.8 and 2.5 ppb for the High, Low and Medium Scenarios, respectively, occurring in the Uinta Basin. Source Group R also contributes ~1.5, ~0.1 and ~0.8 ppb to ozone exceedances in the Denver area for the High, Low and Medium Development Scenarios. Add in new non-Federal O&G that is contained in Source Group T greatly increases the O&G contribution to exceedances in the Denver area with contributions of ~4, ~1 and ~1 ppb for the High, Low and Medium Development Scenarios, respectively (Figure 5-7b, left). Add in the O&G emissions from the Uinta Basin (Source Group U) results in contributions of ~30 ppb to ozone exceedances in the Uinta Basin (Figure 5-7b, right).

Table 5-41a. Maximum ozone contribution by Source Group to total modeled 2021 4th high DMAX8 ozone greater than the NAAQS for the 2021 High Development Scenario.

Group	Name	Max		
		Max Contribution (ppb)	Corresponding 4th MDA8	% Max Contribution
A	Little Snake FO	0.2586	76.7	0.34%
B	White River FO	1.8306	76.5	2.39%
C	Colorado River Valley FO (CRVFO)	0.1765	76.5	0.23%
D	Roan Plateau Planning area portion of CRVFO	0.1608	76.5	0.21%
E	Grand Junction FO	0.7570	77.3	0.98%
F	Uncompahgre FO	0.0725	76.5	0.09%
G	Tres Rios FO	0.6715	76.7	0.88%
H	Kremmling FO	0.0678	76.8	0.09%
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0073	76.0	0.01%
J	Pawnee Grasslands portion of RGFO#1	0.0321	76.0	0.04%
K	RGFO#2 – West-Central/South	0.0015	76.0	0.00%
L	RGFO#3 – South	0.0030	76.0	0.00%
M	RGFO#4 – East-Central	0.0039	76.0	0.01%
N	New Mexico Farmington District	0.2340	78.0	0.30%
O	Total Colorado River Field Office	0.3374	76.5	0.44%
P	Total Royal Gorge Field Office	0.0477	76.0	0.06%
Q	Mining from 13 Colorado BLM Planning Areas	0.1104	76.7	0.14%
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	3.2125	76.5	4.20%
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	5.2711	76.5	6.89%
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	5.3221	76.5	6.96%
U	Combined O&G and Mining in 4 km domain	31.9435	76.4	41.80%
V	Natural Emissions	2.6494	76.5	3.46%

Table 5-41b. Maximum ozone contribution by Source Group to total modeled 2021 4th high DMA8 ozone greater than the NAAQS for the 2021 Low Development Scenario.

Group (low O&G)	Name	Max		
		Max Contribution (ppb)	Corresponding 4th MDA8	% Max Contribution
A	Little Snake FO	0.0480	76.4	0.06%
B	White River FO	0.4321	77.0	0.56%
C	Colorado River Valley FO (CRVFO)	0.1406	77.0	0.18%
D	Roan Plateau Planning area portion of CRVFO	0.1043	77.0	0.14%
E	Grand Junction FO	0.0608	76.1	0.08%
F	Uncompahgre FO	0.0249	77.0	0.03%
G	Tres Rios FO	0.0926	76.0	0.12%
H	Kremmling FO	0.0021	76.3	0.00%
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0021	76.3	0.00%
J	Pawnee Grasslands portion of RGFO#1	0.0104	76.3	0.01%
K	RGFO#2 – West-Central/South	0.0000	76.9	0.00%
L	RGFO#3 – South	0.0002	77.0	0.00%
M	RGFO#4 – East-Central	0.0015	76.3	0.00%
N	New Mexico Farmington District	0.2342	78.0	0.30%
O	Total Colorado River Field Office	0.2449	77.0	0.32%
P	Total Royal Gorge Field Office	0.0140	76.3	0.02%
Q	Mining from 13 Colorado BLM Planning Areas	0.1164	76.4	0.15%
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	0.8622	77.0	1.12%
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	2.1963	77.0	2.85%
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	2.2502	77.0	2.92%
U	Combined O&G and Mining in 4 km domain	30.7272	77.0	39.93%
V	Natural Emissions	2.8167	77.0	3.66%

Table 5-41c. Maximum ozone contribution by Source Group to total modeled 2021 4th high DMA8 ozone greater than the NAAQS for the 2021 Medium Development Scenario.

Group (medium O&G)	Name	Max		
		Max Contribution (ppb)	Corresponding 4th MDA8	% Max Contribution
A	Little Snake FO	0.2360	76.7	0.31%
B	White River FO	1.6579	76.3	2.17%
C	Colorado River Valley FO (CRVFO)	0.1461	76.3	0.19%
D	Roan Plateau Planning area portion of CRVFO	0.1353	78.0	0.17%
E	Grand Junction FO	0.6520	77.1	0.85%
F	Uncompahgre FO	0.0576	76.3	0.08%
G	Tres Rios FO	0.5825	76.7	0.76%
H	Kremmling FO	0.0594	76.8	0.08%
I	Royal Gorge FO Area#1 (RGFO#1) -- North	0.0003	77.1	0.00%
J	Pawnee Grasslands portion of RGFO#1	0.0019	77.1	0.00%
K	RGFO#2 – West-Central/South	0.0002	77.1	0.00%
L	RGFO#3 – South	0.0002	77.1	0.00%
M	RGFO#4 – East-Central	0.0019	76.3	0.00%
N	New Mexico Farmington District	0.1829	78.0	0.23%
O	Total Colorado River Field Office	0.2807	78.0	0.36%
P	Total Royal Gorge Field Office	0.0043	77.1	0.01%
Q	Mining from 13 Colorado BLM Planning Areas	0.1111	76.6	0.14%
R	Combined new Federal O&G and Mining from the 13 Colorado BLM Planning Areas	2.8433	76.3	3.73%
S	Combined new Federal and non-Federal O&G and Mining from 13 Colorado BLM Planning Areas	4.8718	76.3	6.39%
T	Cumulative Emissions Scenario – New Federal and non-Federal O&G from 14 BLM Planning Areas plus mining in the 14 BLM Planning Areas	4.9114	76.3	6.44%
U	Combined O&G and Mining in 4 km domain	31.7908	78.0	40.75%
V	Natural Emissions	2.6588	76.3	3.49%

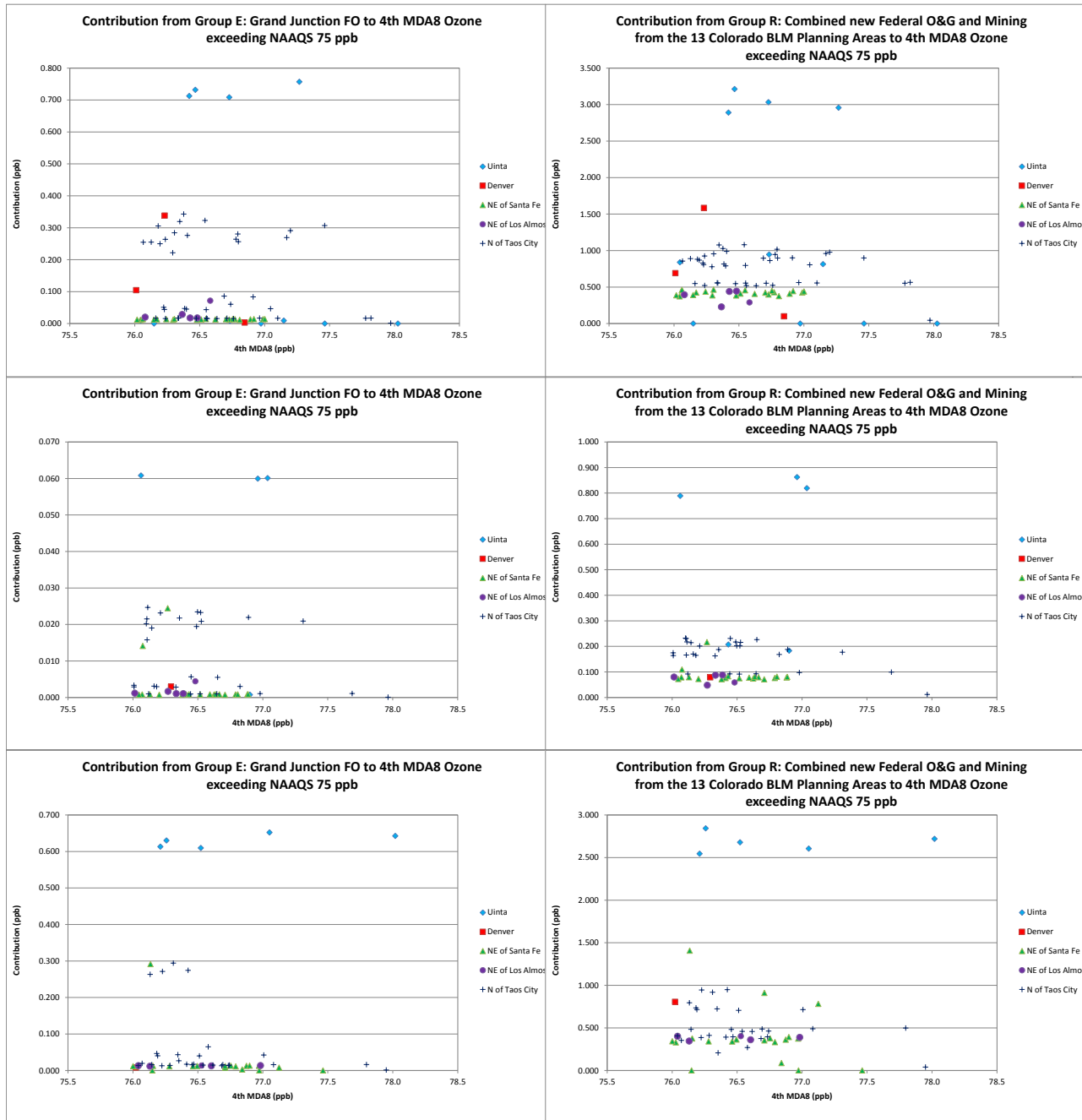


Figure 5-7a. Contributions of Federal O&G from the GJFO (Source Group E; left) and new Federal O&G and mining in the 13 Colorado Planning Areas (Source Group R; right) to modeled fourth highest daily maximum 8-hour ozone concentrations greater than the NAAQS for the 2021 High (top), Low (middle) and Medium (bottom) Development Scenarios.

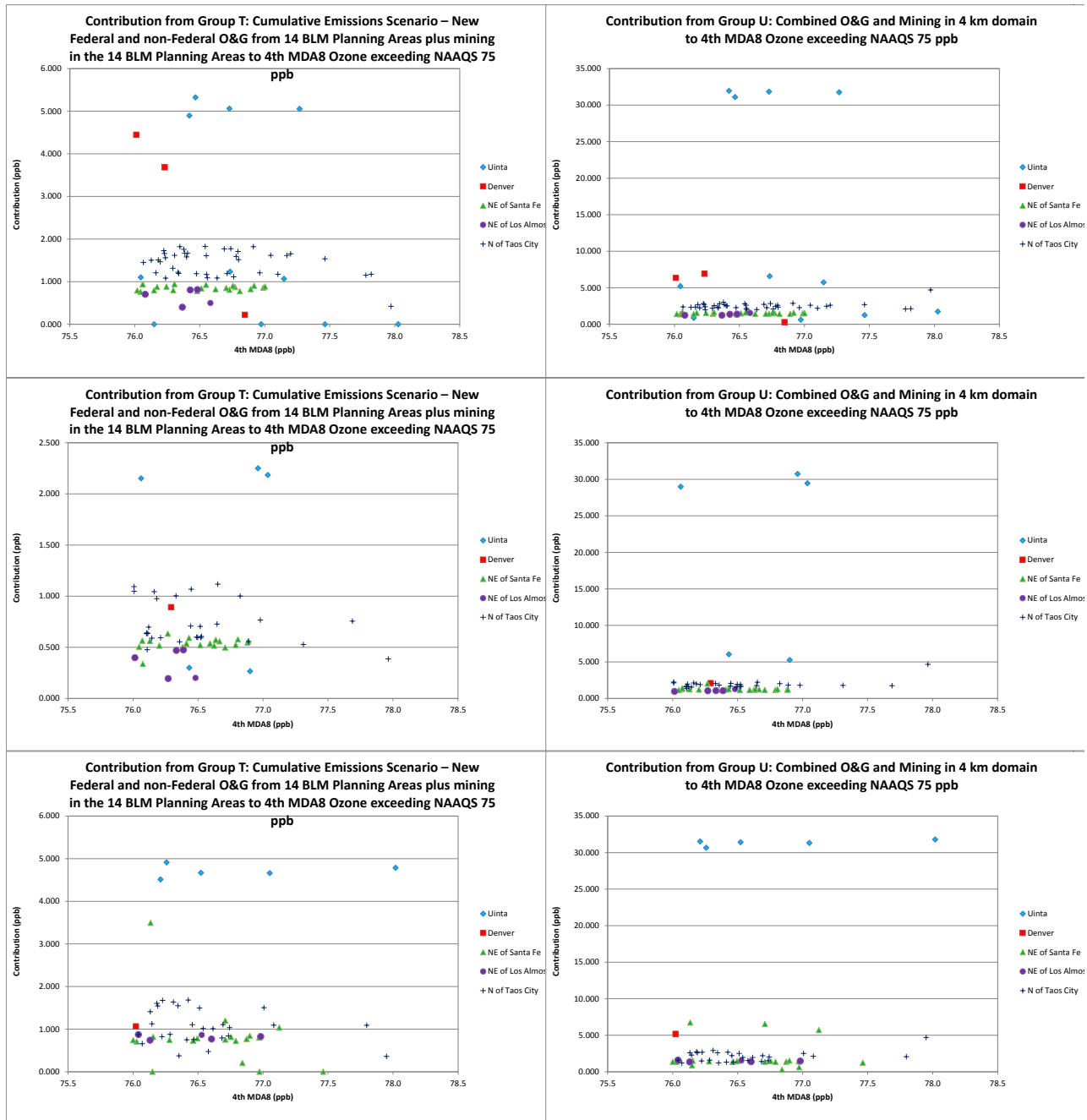


Figure 5-7b. Contributions of new Federal and non-Federal O&G and mining from the 14 BLM Planning Areas (Source Group T; left) and all O&G within the 4 km CARMMS domain plus Colorado Federal mining (Source Group U; right) to modeled fourth highest daily maximum 8-hour ozone concentrations greater than the NAAQS for the 2021 High (top), Low (middle) and Medium (bottom) Development Scenarios.

5.6.3 PM_{2.5} NAAQS Analysis

There are two PM_{2.5} NAAQS, one for a 24-hour averaging time that is expressed as a three-year average of the 98th percentile value in a year with a threshold of 35 µg/m³ and an annual average over three-years with a threshold of 12 µg/m³. With a complete year of modeling results, the 98th percentile corresponds to the 8th highest daily PM_{2.5} concentration in a year.

5.6.3.1 24-Hour PM_{2.5} NAAQS Analyses

Figure 5-8 displays the 8th highest 24-hour PM_{2.5} concentrations for the 2008 Base Case and 2021 emission scenarios and their differences and the contributions of Natural Emissions to the 8th highest 24-hour PM_{2.5} concentration. The maximum 8th high 24-hour PM_{2.5} in 2008 (670 µg/m³) and 2021 High, Low and Medium Development Scenarios (671 µg/m³) far exceeds the 35 µg/m³ NAAQS (Figure 5-8, top panels). This high value occurs on the southern border of the CARMMS 4 km domain and is due to emissions from wildfires, as shown by its absence when Natural Emissions are removed (Figure 5-8, bottom right). Even without Natural Emissions, there are several areas where the model-estimated 8th highest 24-hour PM_{2.5} concentration exceeds the NAAQS in the 2021 emissions scenarios as shown in Figure 5-9 for the 2021 High Development Scenario. These 24-hour PM_{2.5} exceedance areas are identified in Figure 5-9 with numbered labels. In the analysis below we group several exceedance grid cells together: North NM (Areas 13-18); Arizona (Areas 7-9); and Central NM (Areas 11-12).

Attachments H-1, H-2 and H-3 display Source Group's contribution to 8th highest 24-hour PM_{2.5} concentrations when the total concentration is above the NAAQS for the, respectively, 2021 High, Low and Medium Development Scenarios. Figure 5-10 from Attachment H-1 displays the contributions of Natural Emissions (Source Group V) and Federal mining in Colorado (Source Group Q) to the 8th highest 24-hour PM_{2.5} concentration in the 2021 High Development Scenario when it exceeds the 24-hour PM_{2.5} NAAQS. The exceedances in Ruidoso NM (Area 10) and North NM (Areas 13-18) appear to be due to wildfires (Natural Emissions) based on the top panel in Figure 5-10. Mining on Federal lands (Source Group Q) is causing the exceedance in South Moffat County (Area 3) based on the bottom panel in Figure 5-10.

The contributions to the 8th highest daily PM_{2.5} concentrations that exceed the NAAQS from Source Groups R and S and the 2021 High Development Scenario are shown in Figure 5-11. For Source Group R, the scale has been set at a maximum of 0.25 µg/m³ (Figure 5-11, top) so the 45.8 µg/m³ contribution from mining in South Moffat County that was seen in Figure 5-10 (bottom) is not shown. This figure indicates that new Federal O&G within the 13 CO BLM Planning Areas contribute less than 0.25 µg/m³ when the modeled 2021 8th highest 24-hour PM_{2.5} concentration exceeds the NAAQS (Figure 5-11, top). Adding in the non-Federal O&G emissions (Source Group S; Figure 5-11, bottom) we see contributions due to non-Federal O&G to modeled exceedances of the NAAQS as high as 15 µg/m³ that is due to non-Federal O&G emissions in the RGFO Planning Area north of Denver (Weld County).

Figure 5-12 displays the contributions of Federal O&G from the GRFO, UFO and USFS-PG Planning Areas and combined Source Group R (new Federal O&G and mining in 13 Colorado Planning Areas) to the 8th highest 24-hour PM_{2.5} concentrations for the 2021 High Development Scenario. Results for the 2021 Low and Medium Development Scenario are lower and can be

found in Attachment I. The maximum contribution to 8th highest 24-hour PM_{2.5} concentration due to emissions from new Federal O&G in these four Source Groups and the 2021 High, Low and Medium Development Scenarios are: 1.2, 0.1 and 0.8 µg/m³ (GJFO), 0.3, 0.1 and 0.2 µg/m³ (UFO), 0.6, 0.1 and 0.2 (USFS-PG) and 39.8, 29.8 and 39.8 µg/m³ (Source Group R) (Table 5-42). The maximum contribution due to new Federal O&G and mining from all of the Colorado BLM Planning areas is 39.8 µg/m³ that is due to a coal mine in the LSFO Planning Area, which explains the maximum contribution of Source Group R.

Figure 5-13 shows the contributions of new Federal and non-Federal O&G and mining in the 14 BLM Planning Areas (Source Group T) and all O&G emissions in the 4 km CARMMS domain (Source Group U) for the 2021 High, Low and Medium Development Scenarios. The maximum 24-hour PM_{2.5} contribution in all four panels in Figure 5-12 is essentially identical (40 µg/m³) and is due to a coal mine in the LSFO Planning Area. 24-hour PM_{2.5} contributions in excess of 3 µg/m³ can be seen in the D-J and Piceance Basins and the Uinta Basin for Source Group U.

Table 5-42 summarizes the maximum contribution to the 8th highest 24-hour PM_{2.5} concentrations for all of the Source Groups and the 2021 High, Low and Medium Development Scenarios. For most BLM Planning Areas, the contribution of Federal O&G to the 8th highest 24-hour PM_{2.5} concentrations is small, less than 1 µg/m³. The exception to this is new Federal O&G emissions from the WRFO (5.6, 0.6 and 3.2 µg/m³) and GJFO (1.2, 0.1 and 0.8 µg/m³) Planning Areas. As noted previously, mining on Federal lands in the LSFO contributes a maximum of 39.8 µg/m³ to the 8th highest 24-hour PM_{2.5} concentration; the mining contribution drives the maximum contribution for all of the combination Source Groups (Q through U).

The year 2021 minus year 2008 impacts difference plots (bottom left of Figures 5-8a, 5-8b and 5-8c) while comparing plots for Source Groups R and T indicates relatively large increases in 24-hour PM_{2.5} concentrations primarily due to new non-Federal oil and gas in the RGFO. It should be noted that unpaved road traffic and construction fugitive dust emissions were calculated by the BLM COSO for all new RGFO Federal and non-Federal oil and gas development and the year 2008 emissions inventory did not account for total oil and gas related traffic / construction fugitive dust and therefore, the difference plots concentration changes (year 2021 minus year 2008) are overestimates.

Table 5-42a. Maximum contribution to the 8th high 24-hour PM_{2.5} concentrations (µg/m³) for each of the Source Groups and the 2021 High, Low and Medium Development Scenarios.

Source Group	24-Hour PM _{2.5} (µg/m ³)		
	High	Low	Medium
A. Little Snake FO	0.8	0.2	0.6
B. White River FO	5.6	0.6	3.2
C. CRVFO (No Roan)	0.4	0.2	0.3
D. Roan Plateau	0.3	0.1	0.3
E. Grand Junction FO	1.2	0.1	0.8
F. Uncompahgre FO	0.3	0.1	0.2
G. Tres Rios FO	0.3	0.0	0.2
H. Kremmling FO	0.1	0.0	0.0
I. Royal Gorge FO No. 1	0.2	0.0	0.1
J. Pawnee Grasslands	0.6	0.1	0.2
K. Royal Gorge FO No. 2	0.1	0.0	0.0
L. Royal Gorge FO No. 3	0.0	0.0	0.0
M. Royal Gorge FO No. 4	0.1	0.0	0.0
N. NMFFO (Mancos)	0.5	0.6	0.4
O. CRVFO (w/ Roan)	0.7	0.3	0.5
P. Royal Gorge FO (total)	0.7	0.2	0.2
Q. Federal Mining in CO	39.8	39.8	39.8
R. New Federal O&G/Mining in CO	39.8	39.8	39.8
S. New O&G/Mining in CO	40.0	39.8	39.9
T. New O&G/Mining in CO/NM	40.0	39.8	39.9
U. All O&G in 4 km Domain	40.0	40.0	40.0
V. Natural Emissions	658.2	658.2	658.2

Table 5-42b. Maximum contribution to the annual PM_{2.5} concentrations (µg/m³) for each of the Source Groups and the 2021 High, Low and Medium Development Scenarios.

Source Group	Annual PM _{2.5} (µg/m ³)		
	High	Low	Medium
A. Little Snake FO	0.7	0.1	0.5
B. White River FO	4.4	0.7	2.6
C. CRVFO (No Roan)	0.3	0.2	0.2
D. Roan Plateau	0.2	0.1	0.2
E. Grand Junction FO	1.0	0.1	0.6
F. Uncompahgre FO	0.2	0.1	0.1
G. Tres Rios FO	0.4	0.1	0.2
H. Kremmling FO	0.0	0.0	0.0
I. Royal Gorge FO No. 1	0.1	0.0	0.0
J. Pawnee Grasslands	0.2	0.0	0.1
K. Royal Gorge FO No. 2	0.0	0.0	0.0
L. Royal Gorge FO No. 3	0.0	0.0	0.0
M. Royal Gorge FO No. 4	0.1	0.0	0.0
N. NMFFO (Mancos)	0.3	0.3	0.2
O. CRVFO (w/ Roan)	0.5	0.3	0.3
P. Royal Gorge FO (total)	0.3	0.1	0.1
Q. Federal Mining in CO	20.7	20.7	20.7
R. New Federal O&G/Mining in CO	20.7	20.7	20.7
S. New O&G/Mining in CO	20.7	20.7	20.7
T. New O&G/Mining in CO/NM	20.7	20.7	20.7
U. All O&G in 4 km Domain	20.8	20.7	20.8
V. Natural Emissions	26.4	26.4	26.4

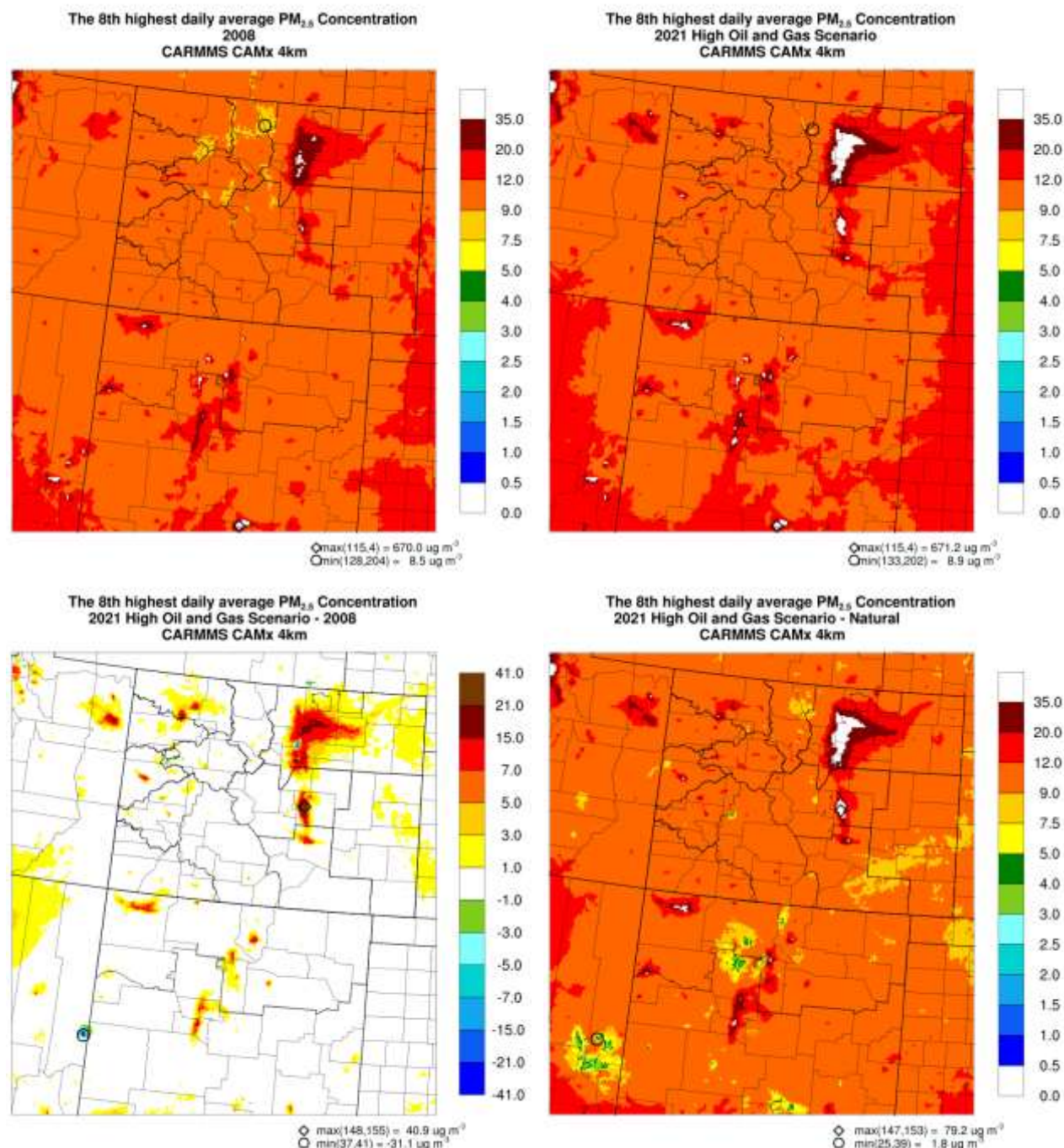


Figure 5-8a. Eighth highest 24-hour $PM_{2.5}$ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 High minus 2008 differences (bottom left) and Natural Emissions (bottom right).

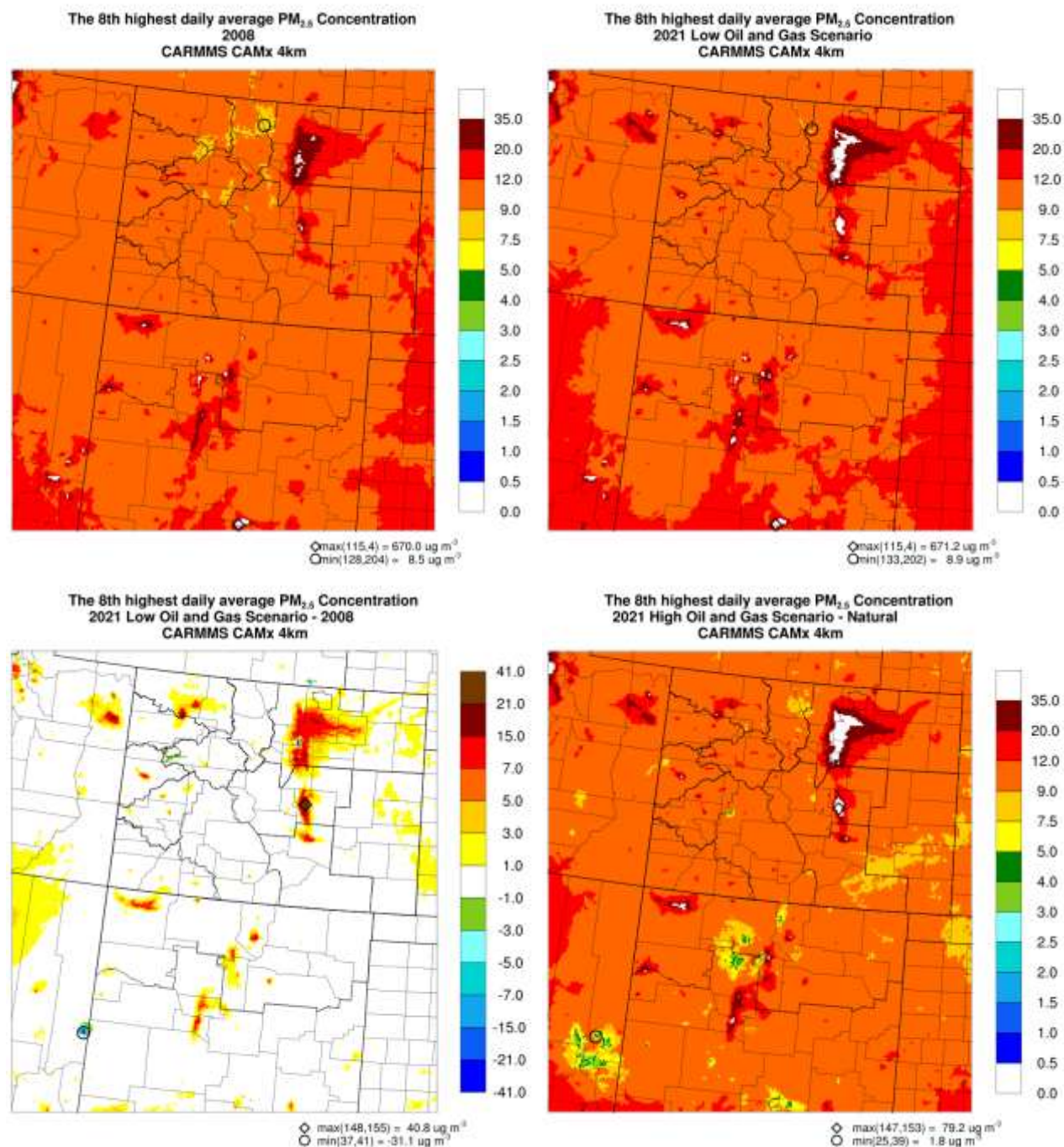


Figure 5-8b. Eighth highest 24-hour PM_{2.5} concentrations for the 2008 Base Case (top left), 2021 Low Development Scenario (top right), 2021 Low minus 2008 differences (bottom left) and Natural Emissions (bottom right).

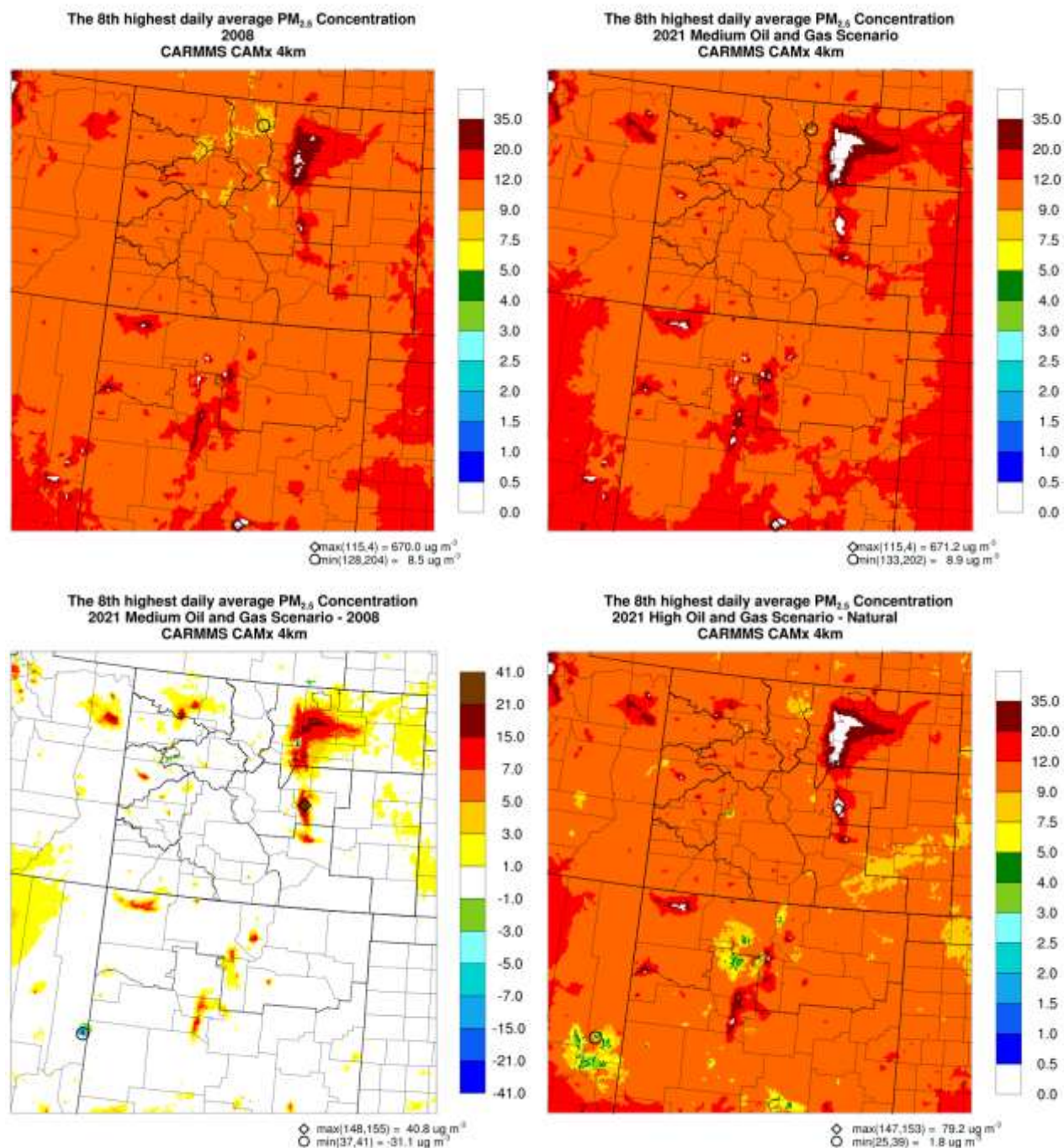


Figure 5-8c. Eighth highest 24-hour $PM_{2.5}$ concentrations for the 2008 Base Case (top left), 2021 Medium Development Scenario (top right), 2021 Medium minus 2008 differences (bottom left) and Natural Emissions (bottom right).

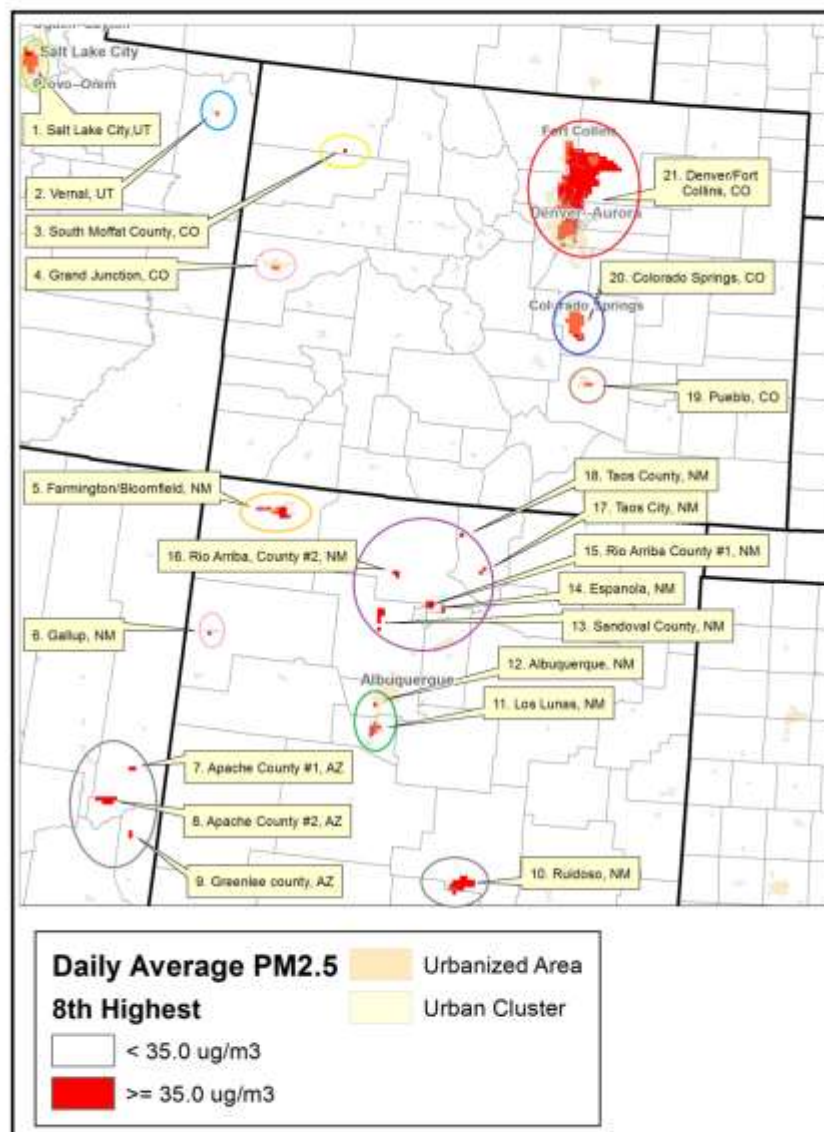


Figure 5-9. Locations of grid cells with modeled 2021 High Development Scenario 8th highest 24-hour PM_{2.5} concentrations above the 35 µg/m³ NAAQS.

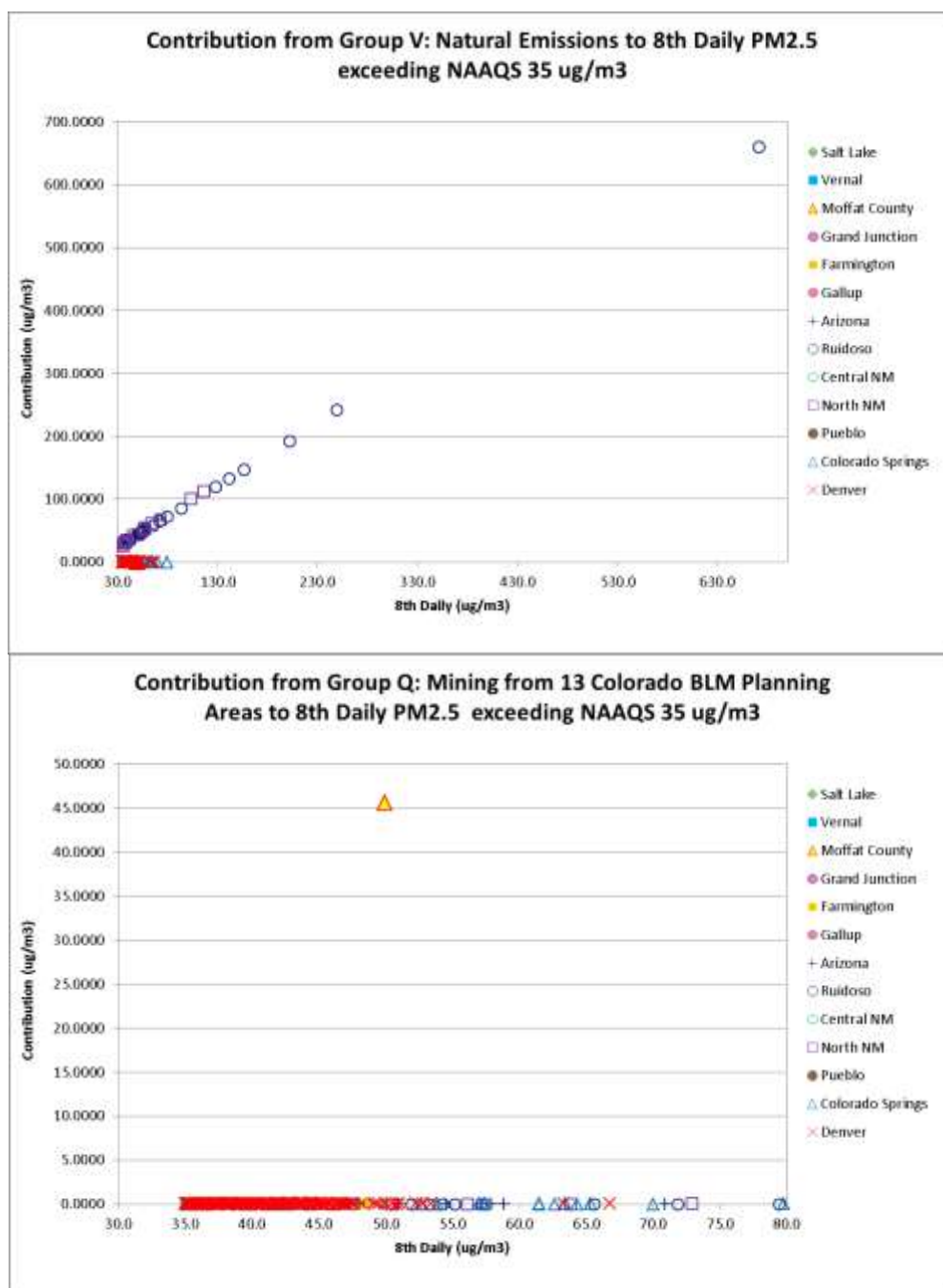


Figure 5-10. Natural Emissions (Source Group V, top) and Mining of Federal land in Colorado (Source Group Q, bottom) contributions to the modeled 8th highest 24-hour PM_{2.5} concentration from the 2021 High Development Scenario.

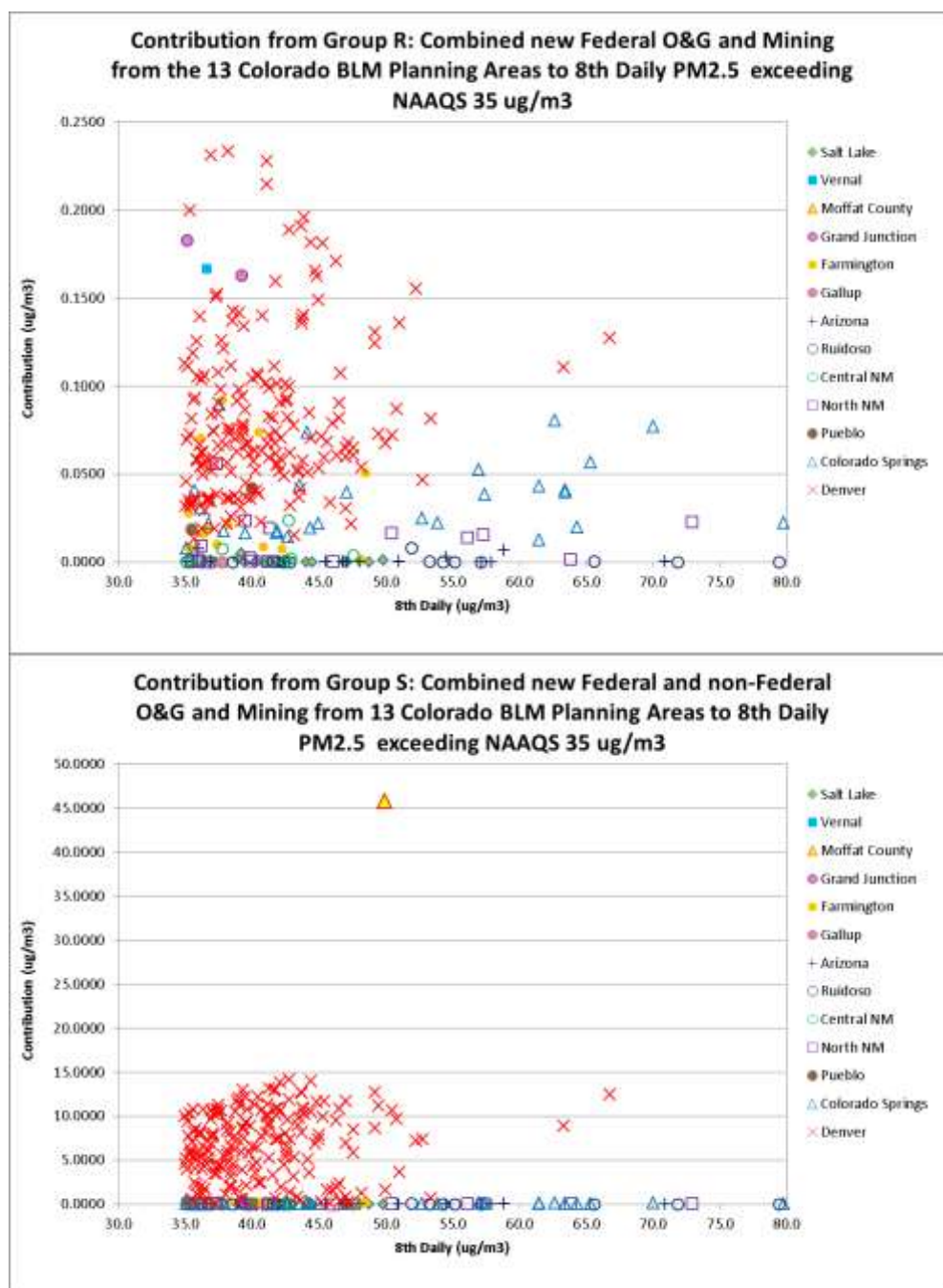


Figure 5-11. Natural Emissions (Source Group V, top) and Mining of Federal land in Colorado (Source Group Q, bottom) contributions to the modeled 8th highest 24-hour PM_{2.5} concentration from the 2021 High Development Scenario.

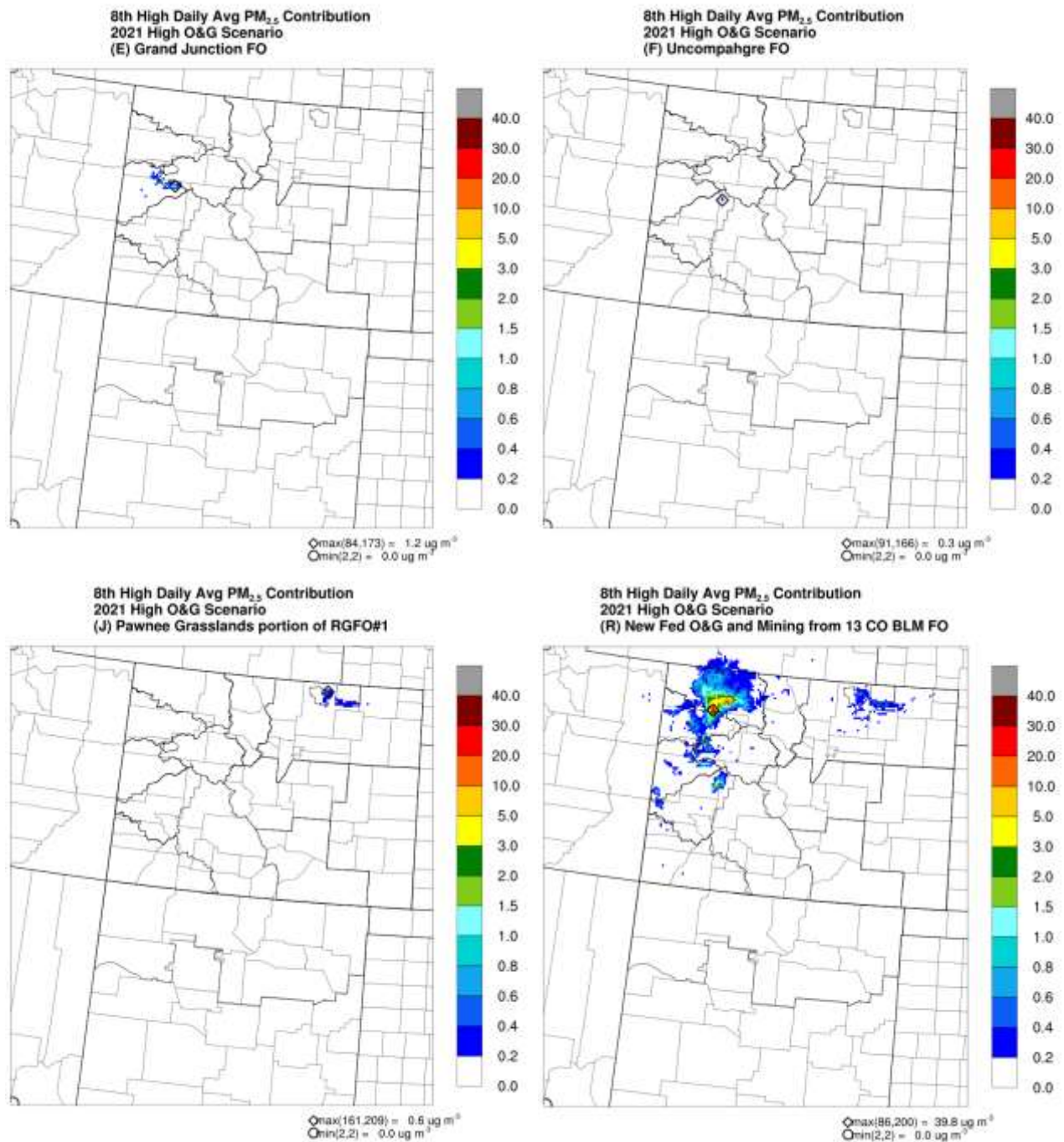


Figure 5-12. Contribution to 8th highest daily PM_{2.5} concentrations due to emissions from new Federal O&G within the GJFO (top left), UFO (top right) and USFS-PG (bottom left) Planning Areas and new Federal O&G and mining within the 13 Colorado BLM Planning Areas (bottom right) for the 2021 High Development Scenario.

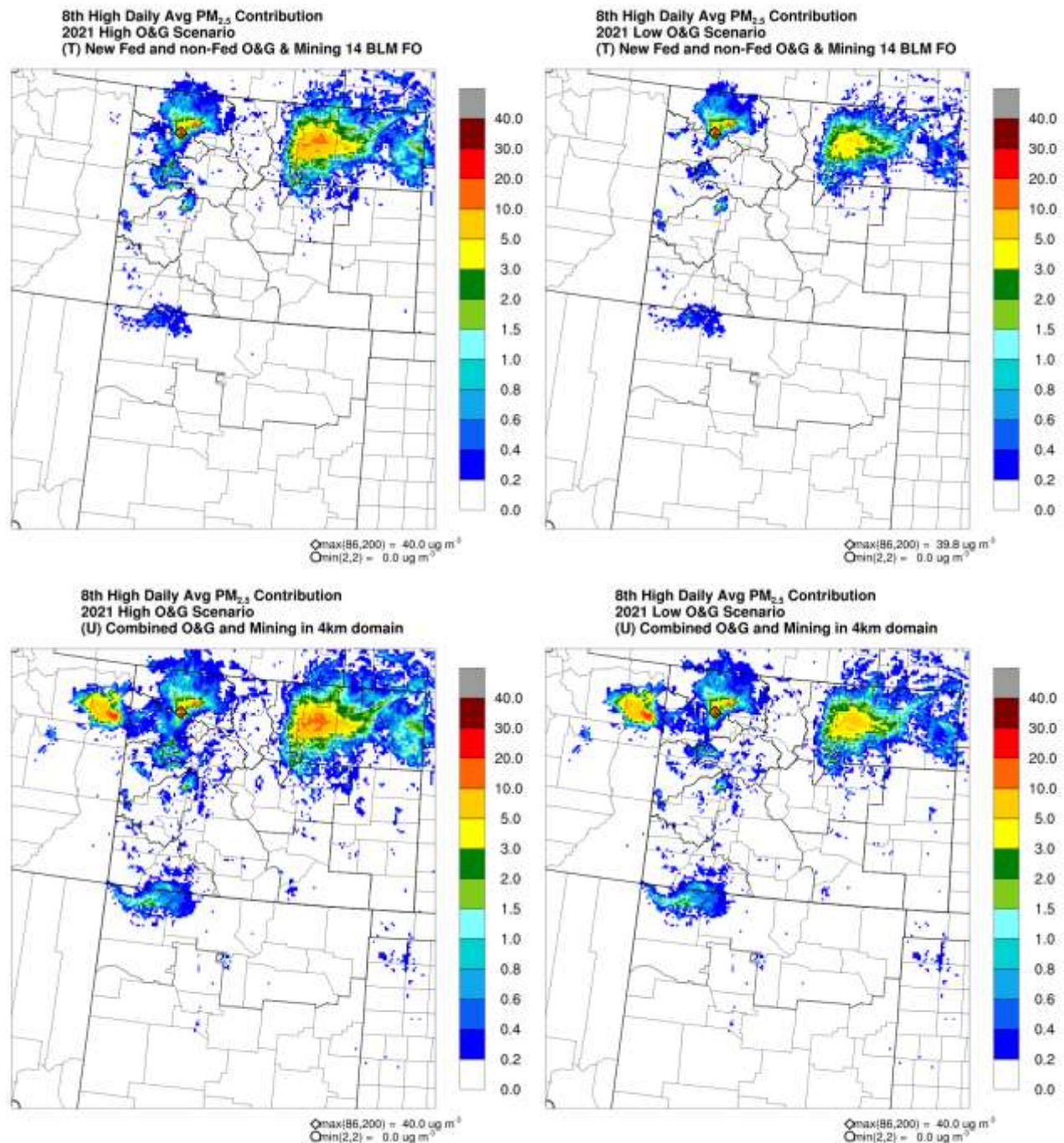


Figure 5-13. Contribution to 8th highest daily PM_{2.5} concentrations due to emissions from new Federal and non-Federal O&G and mining within the 14 BLM Planning Areas (top) and all O&G emissions within the 4 km CARMMS domain (bottom) for the 2021 High (left) and Low (right) Development Scenarios.

5.6.3.2 Annual PM_{2.5} NAAQS Analysis

Figure 5-14 displays the annual average PM_{2.5} concentrations for the 2008 Base Case and 2021 emissions scenarios and their differences and the annual average PM_{2.5} concentrations without Natural Emissions. The highest annual average PM_{2.5} concentration is ~30 µg/m³ in the 2008 and 2021 emission scenarios and occurs in the southern most portion of the CARMMS 4 km domain near Ruidoso, NM and is due to wildfires since it is gone when the natural emissions are removed. However, even without Natural Emissions there are several areas where the modeled annual PM_{2.5} concentrations exceed the 12 µg/m³ annual PM_{2.5} NAAQS (red areas in Figure 5-14) in the 2008 Base case and 2021 High and Low Development Scenarios. There are noticeable increases in PM_{2.5} concentrations in Moffat County in the BLM LSFO Planning Area for the 2021 emission scenarios compared to the 2008 base case that are due to higher emissions from mines (Figure 5-14, top two panels). For example, the Colowyo mine PM_{2.5} emissions are 325 TPY in the 2008 base case and 3,400 TPY in the 2021 emission scenarios.

The maximum contribution of each Source Group to annual PM_{2.5} concentrations for the 2021 High and Low Development Scenarios are shown in Table 5-42b. With two exceptions, new Federal O&G within each of the 14 BLM Planning Areas have contributions of less than 1 µg/m³ to annual average PM_{2.5} concentrations. The two exceptions are the WRFO (4.4, 0.7 and 2.6 µg/m³) and GJFO (1.0, 0.1 and 0.6 µg/m³) Planning Areas, and even for those two areas the contributions of the 2021 Low Development Scenario are below 1 µg/m³. Mining on Federal lands in Colorado contributes a maximum of 20.7 µg/m³ due to the coal mine in the LSFO Planning Area. The maximum annual PM_{2.5} due to mining drives the maximum annual PM_{2.5} contributions for all of the combined Source Groups Q through U. Natural emissions (wildfires) contribute a maximum annual PM_{2.5} contribution of 26.4 µg/m³.

Figure 5-15 displays the differences in annual average PM_{2.5} concentrations between the 2021 High Development Scenario and 2021 with the contributions from Source Groups F (UFO), J (USFS-PG), R and T removed; results for the 2021 Low and Medium Development Scenarios are similar but lower and can be found in Attachment I. Very small contributions to annual PM_{2.5} are seen for new Federal O&G from the UFO and USFS-PG Planning Areas (maximum of 0.2 µg/m³). The high contribution of the LSFO coal mine (20.7 µg/m³) is seen in the Source Group R plot (Figure 5-15, bottom left). Relatively high (> 3 µg/m³) contributions to annual average PM_{2.5} are seen in the Source Group T contributions in Weld County (Figure 5-15, bottom right). These higher Weld County PM_{2.5} contributions in Source Group T compared to Source Group R are due to PM_{2.5} emissions from new non-Federal O&G emissions, which is confirmed by the spatial emission plots in Figure 3-10. As noted for PM_{2.5} 24-hour average impacts discussion, unpaved road traffic and construction fugitive dust emissions were calculated by the BLM COSO for all new RGFO Federal and non-Federal oil and gas development and the year 2008 emissions inventory did not account for total oil and gas related traffic / construction fugitive dust and therefore, the difference plots concentration changes (year 2021 minus year 2008) are overestimates.

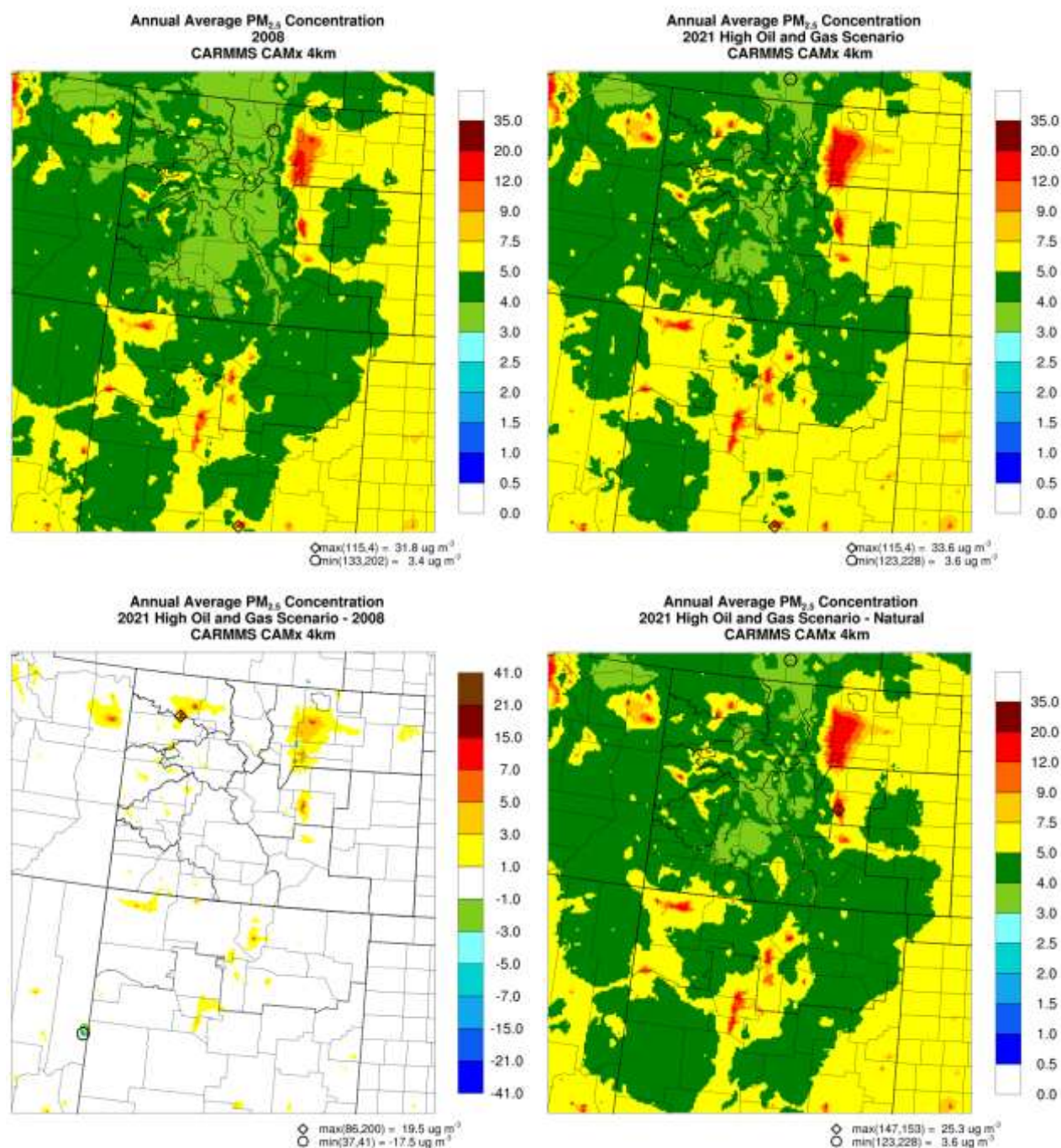


Figure 5-14a. Annual average PM_{2.5} concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 High minus 2008 differences (bottom left) and Natural Emissions (bottom right).

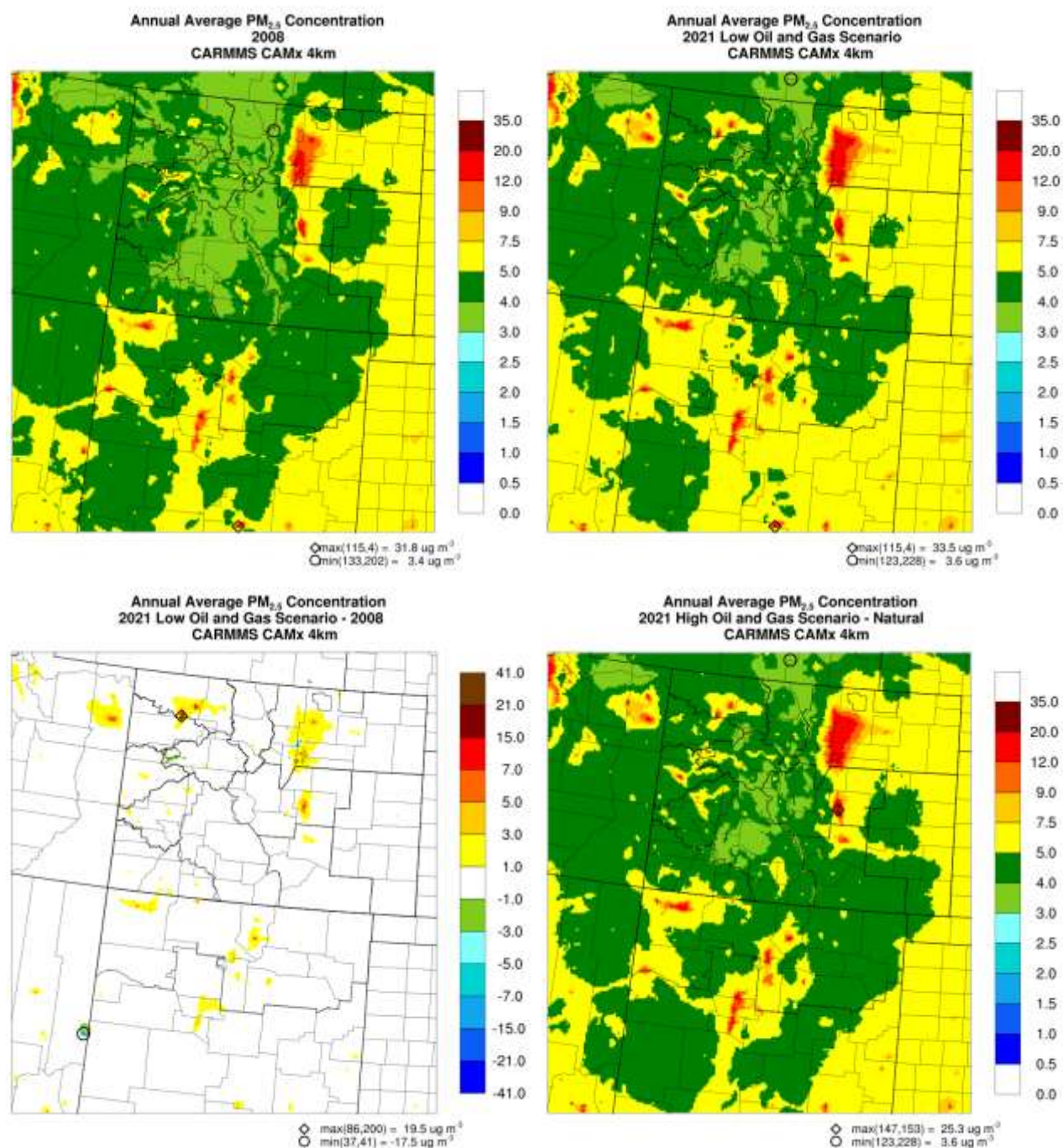


Figure 5-14b. Annual average PM_{2.5} concentrations for the 2008 Base Case (top left), 2021 Low Development Scenario (top right), 2021 Low minus 2008 differences (bottom left) and Natural Emissions (bottom right).

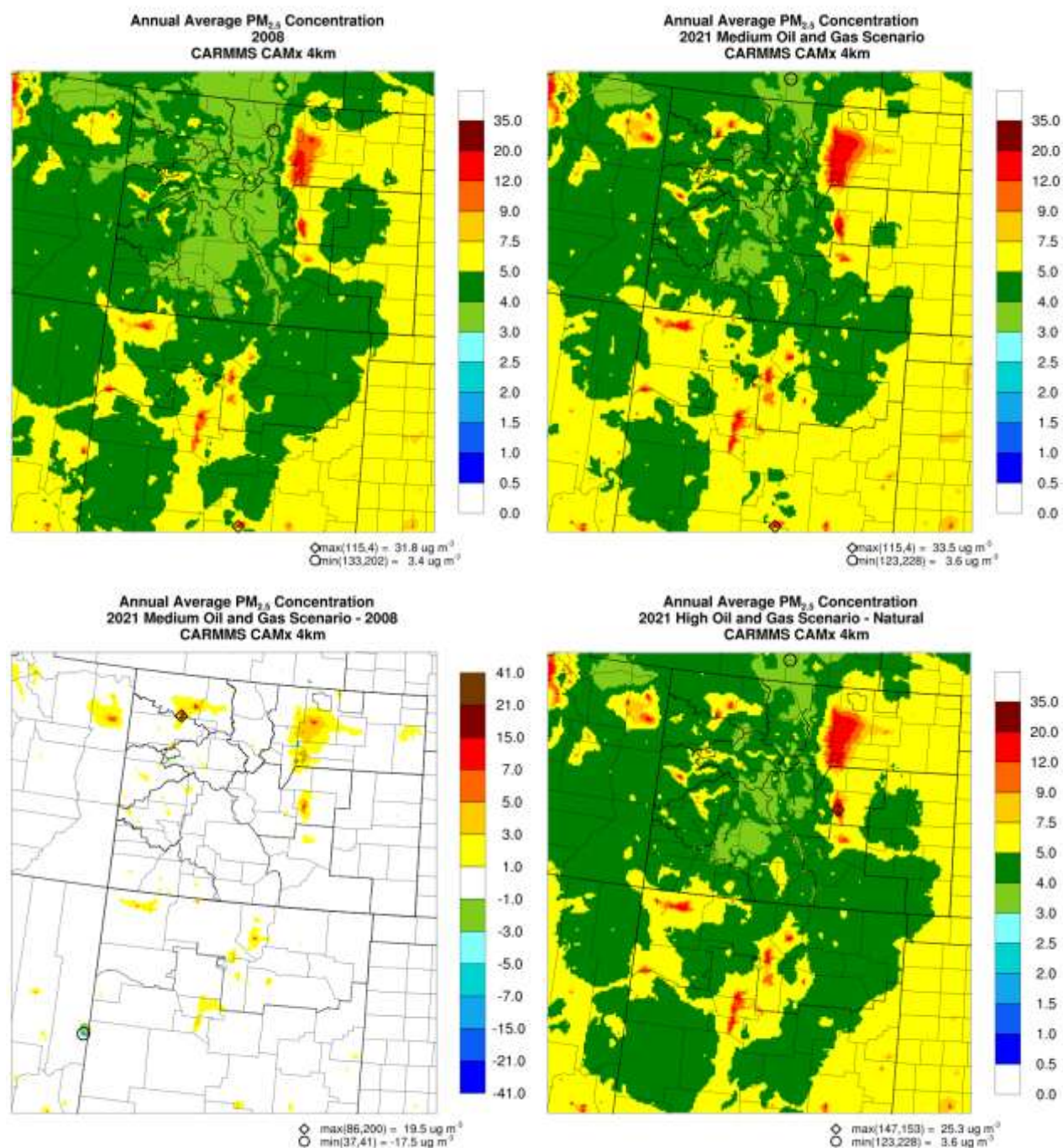


Figure 5-14c. Annual average PM_{2.5} concentrations for the 2008 Base Case (top left), 2021 Medium Development Scenario (top right), 2021 Medium minus 2008 differences (bottom left) and Natural Emissions (bottom right).

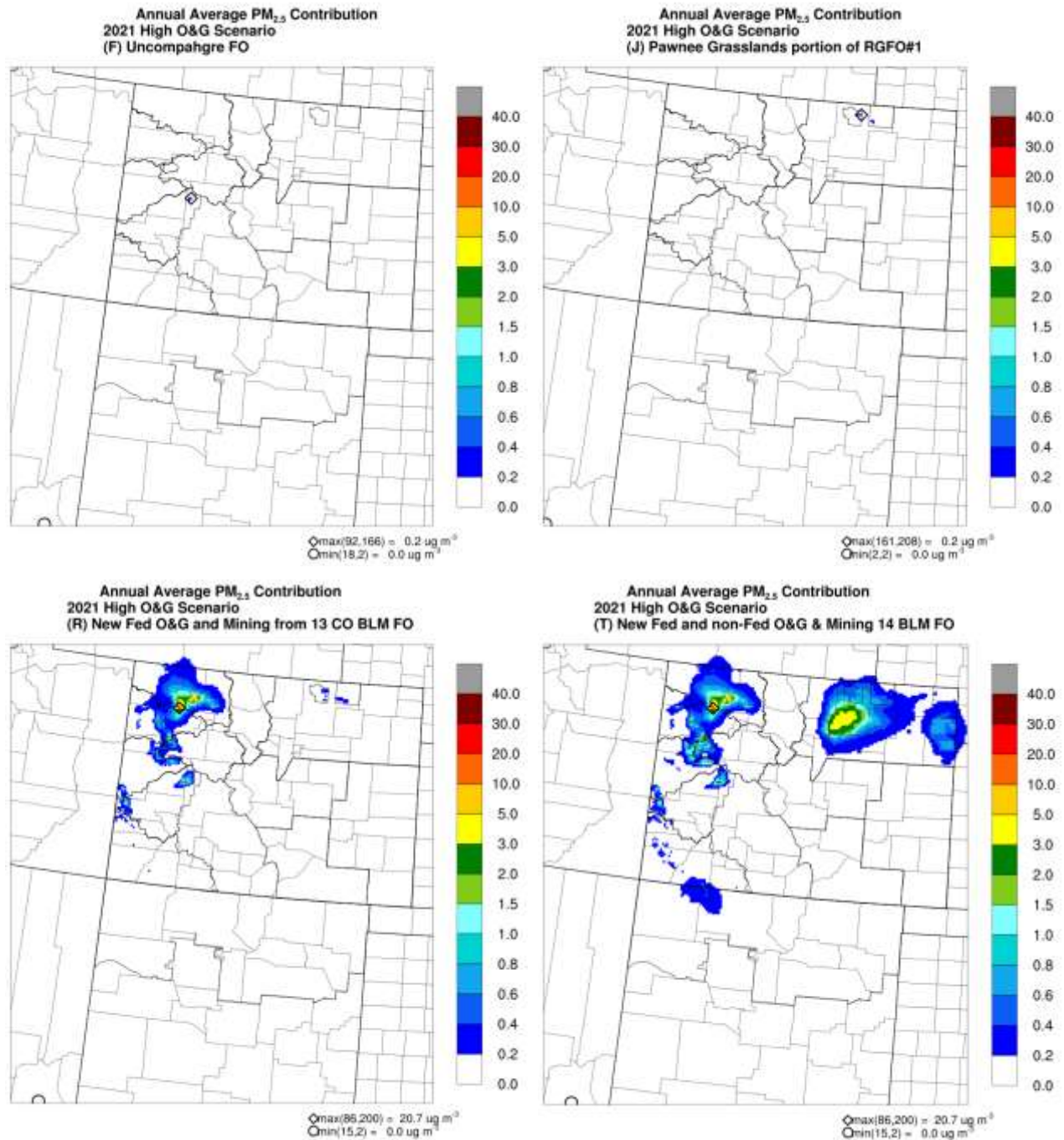


Figure 5-15. Contribution to annual average $PM_{2.5}$ concentrations due to emissions from new Federal O&G within the UFO (top left) and USGS-PG (top right) Planning Areas and new O&G and mining from the 13 Colorado BLM Planning Areas (bottom left) and new Federal O&G and mining and non-Federal O&G from the 14 CO/NM BLM Planning Areas for the 2021 High Development Scenario.

5.6.4 PM₁₀ NAAQS Analysis

Figure 5-16 and 5-17 displays the 2021 High Development Scenario modeling results for 24-hour PM₁₀ that can be compared to the 150 µg/m³ 24-hour PM₁₀ NAAQS. Much of the discussion on 24-hour PM_{2.5} also holds for 24-hour PM₁₀, although there are less exceedances of the 24-hour PM₁₀ NAAQS since the threshold is higher. Extremely high highest second high PM₁₀ concentrations occur in the 2008 and 2021 emissions scenarios that exceed 1,000 µg/m³ (Figure 5-16, top panels). However, when natural emissions are removed the highest PM₁₀ concentration drops to ~390 µg/m³, which is much lower but still above the 24-hour PM₁₀ NAAQS. With two exceptions, the maximum contribution of new Federal O&G emissions to the 2nd highest 24-hour PM₁₀ concentrations from each of the BLM Planning Areas individually is less than 3 µg/m³. The two exceptions and the maximum contributions due to the 2021 High, Low and Medium Development Scenarios are the WRFO (32.2, 3.1 and 11.5 µg/m³) and GJFO (7.9, 0.2 and 3.5 µg/m³) Planning Areas. Mining on Federal lands contributes a maximum of 47.8 µg/m³ to the 2nd high 24-hour PM₁₀ concentrations in all three of the 2021 emission scenarios. The contributions due to new Federal O&G to 2nd high 24-hour PM₁₀ for the UFO and USFS-PG and the 2021 High Development Scenario are shown in the top two panels of Figure 5-17 with very small contributions seen. The bottom two panels in Figure 5-17 show the contributions of Source Groups R and T to the 2nd high 24-hour PM₁₀ concentration for the 2021 High Development Scenario that display the mining contribution in South Moffat County and new non-Federal O&G contribution in Weld County. The contributions of all of the Source Groups and all three 2021 emission scenarios to 24-hour PM₁₀ concentrations can be found in Attachment I.

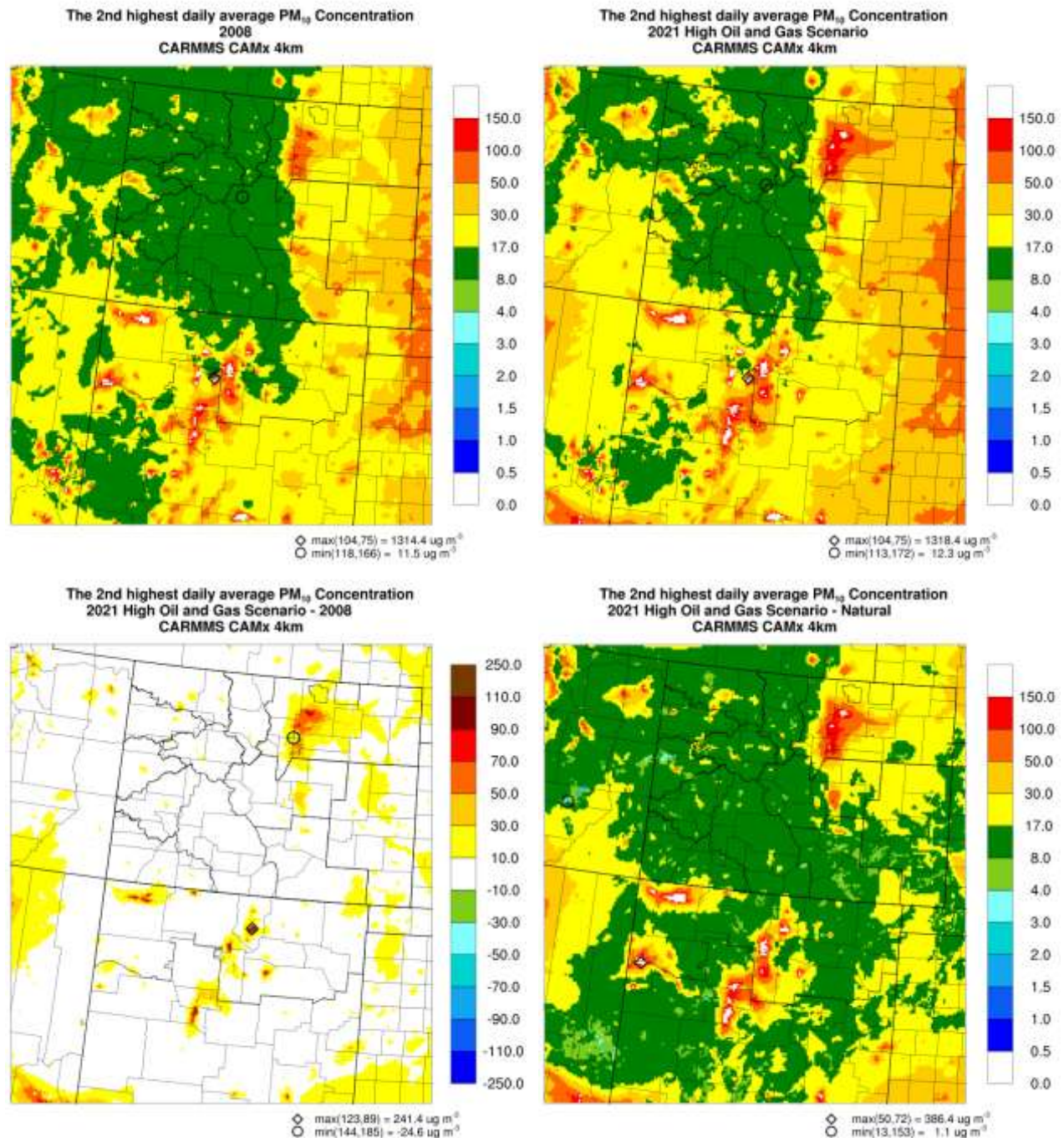


Figure 5-16. Second highest 24-hour average PM₁₀ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 minus 2008 differences (bottom left) and Natural Emissions (bottom right).

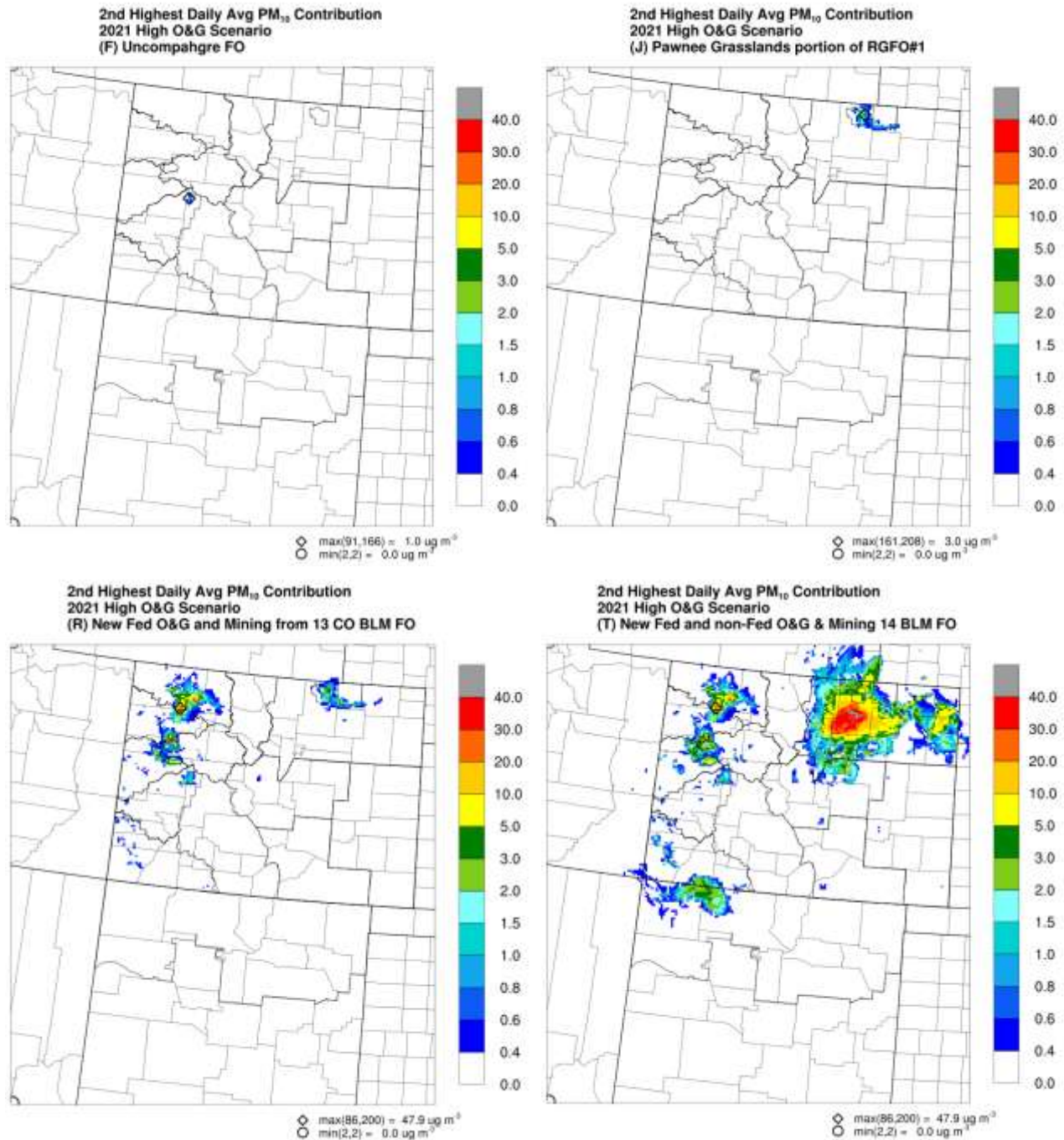


Figure 5-17. Contribution to second highest 24-hour average PM₁₀ concentrations due to emissions from new Federal O&G within the UFO (top left) and USGS-PG (top right) Planning Areas and new O&G and mining from the 13 Colorado BLM Planning Areas (bottom left) and new Federal O&G and mining and non-Federal O&G from the 14 CO/NM BLM Planning Areas for the 2021 High Development Scenario.

5.6.5 SO₂ NAAQS Analysis

The 2008 Base Case and 2021 High Development Scenario, their differences and contributions of Natural Emissions to 1-hour, 3-hour and annual SO₂ concentrations are shown in, respectively, Figures 5-18 through 5-21. The 1-hour SO₂ NAAQS is 196 µg/m³ and it is exceeded when the colors in Figure 5-17 are yellow or hotter. With one exception, the 4th highest daily maximum 1-hour SO₂ concentrations are below the NAAQS throughout the 4 km CARMMS domain for the 2021 High Development Scenario. The exception is an isolated point in northeast Arizona where a value of 212 µg/m³ is seen that is not due to natural emissions (see Figure 5-18, bottom right) or O&G and mining emissions in Colorado or New Mexico that is the focus of CARMMS. With one exception, new Federal O&G emissions in the 14 BLM Planning Areas have very small contributions to 1-hour, 3-hour, 24-hour and annual SO₂ concentrations with contributions being less than 1 µg/m³. The exception is for the WRFO Planning Area (Source Group B) that contributes 78.4, 75.0, 42.7 and 18.0 µg/m³ to the 1-hour, 3-hour, 24-hour and annual average SO₂ concentrations for the 2021 High and Medium Development Scenarios and 12.9, 12.0, 7.0 and 3.0 µg/m³ for the 2021 Low Development Scenario. As noted in Section 3.7, a majority of the SO₂ emissions in the WRFO Planning Area are due to the Meeker and Willow Creek gas plants whose emissions were based on the CDPHE 2008 APEN data grown to 2021 based on the change in gas production within the Piceance Basin between 2008 and 2021. For the 2021 High Development Scenario the 2021 growth factor from 2008 was a factor of 3.4. Example spatial maps showing the SO₂ contributions for Source Groups R and T and the 2021 High Development Scenario are given in Figure 5-22 with other Source Groups and 2021 emission scenarios given in Attachment I.

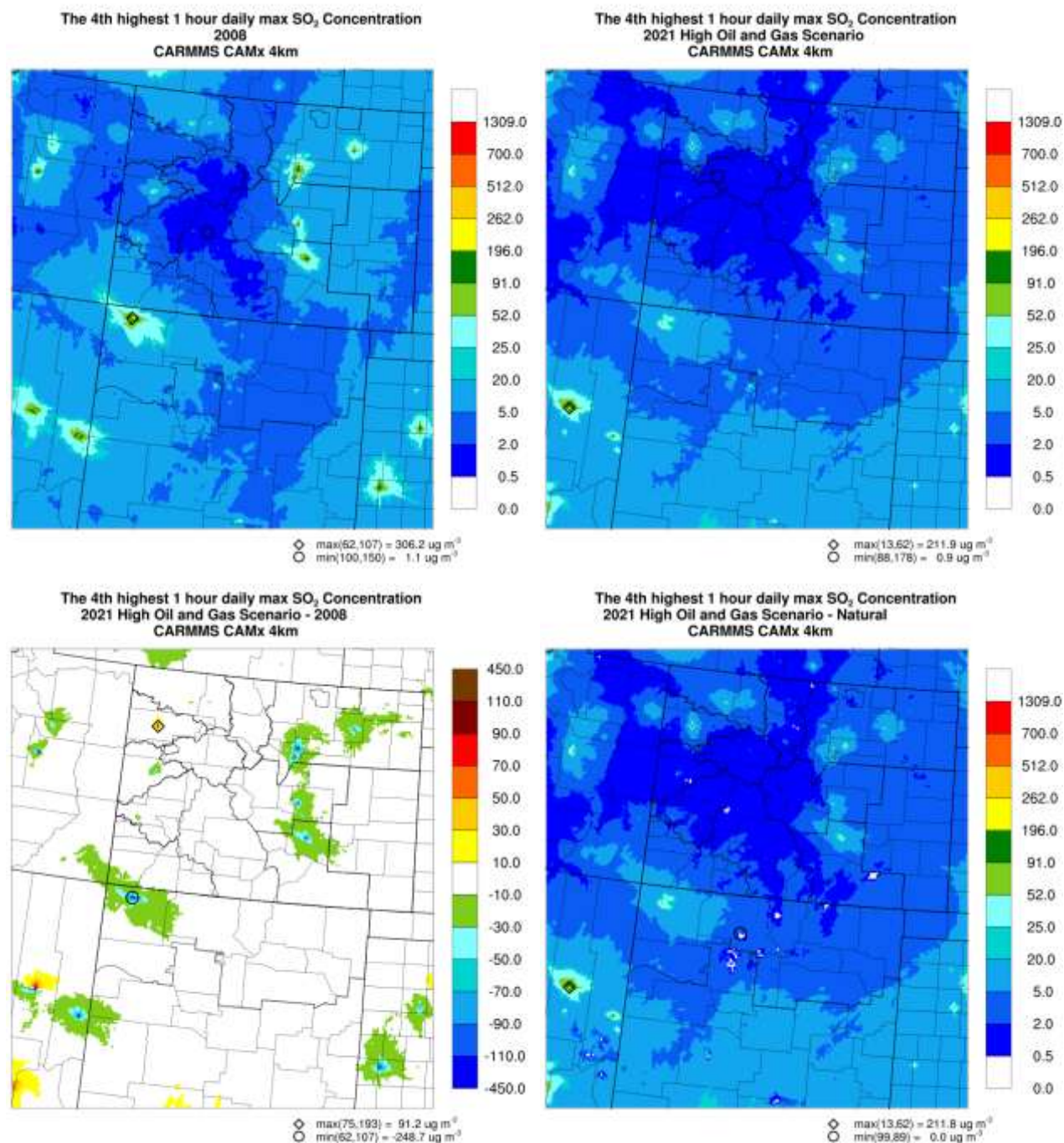


Figure 5-18. Fourth highest (99th percentile) daily maximum 1-hour average SO₂ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 minus 2008 differences (bottom left) and Natural Emissions (bottom right).

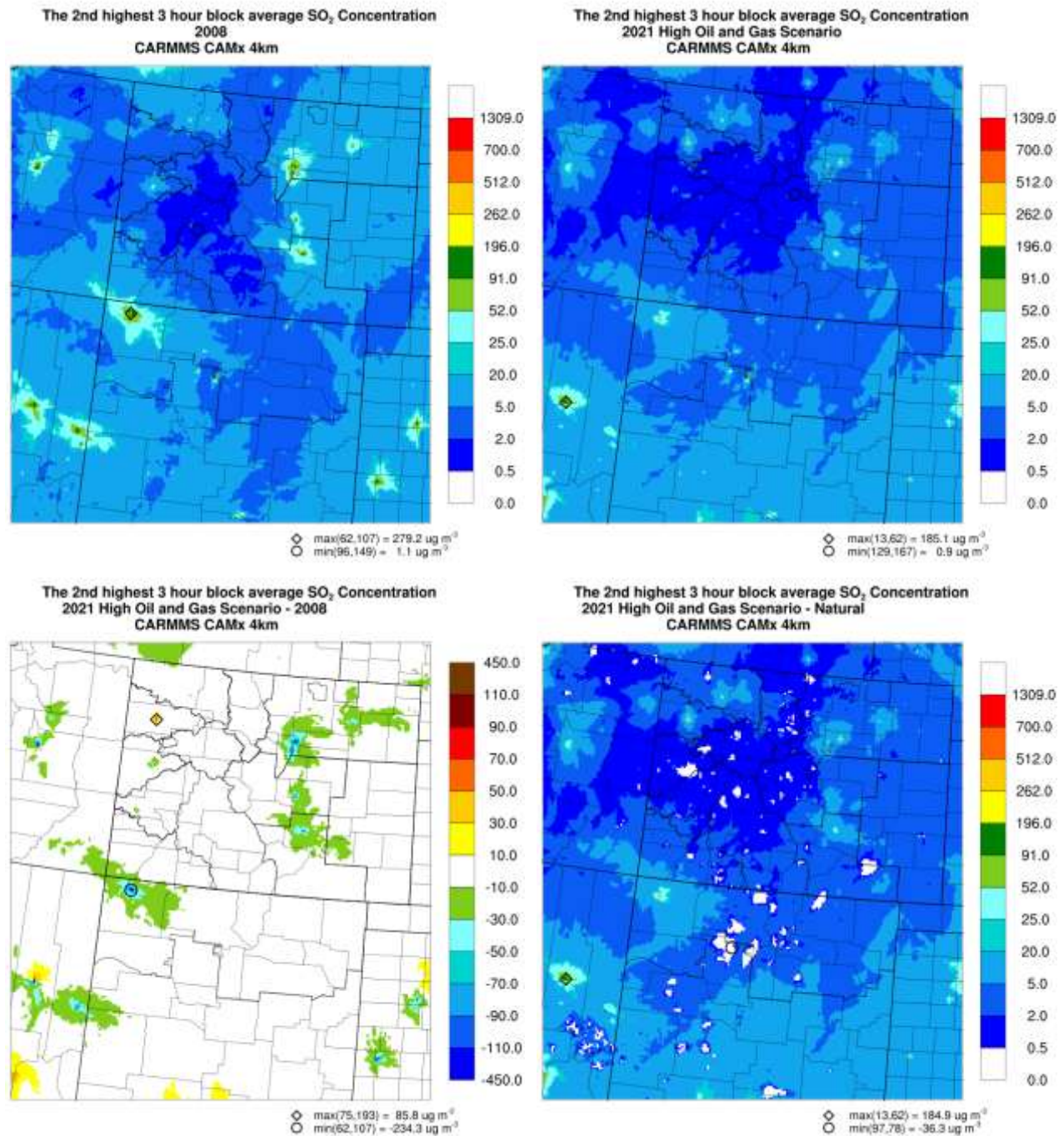


Figure 5-19. Second highest 3-hour average SO₂ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 minus 2008 differences (bottom left) and Natural Emissions (bottom right).

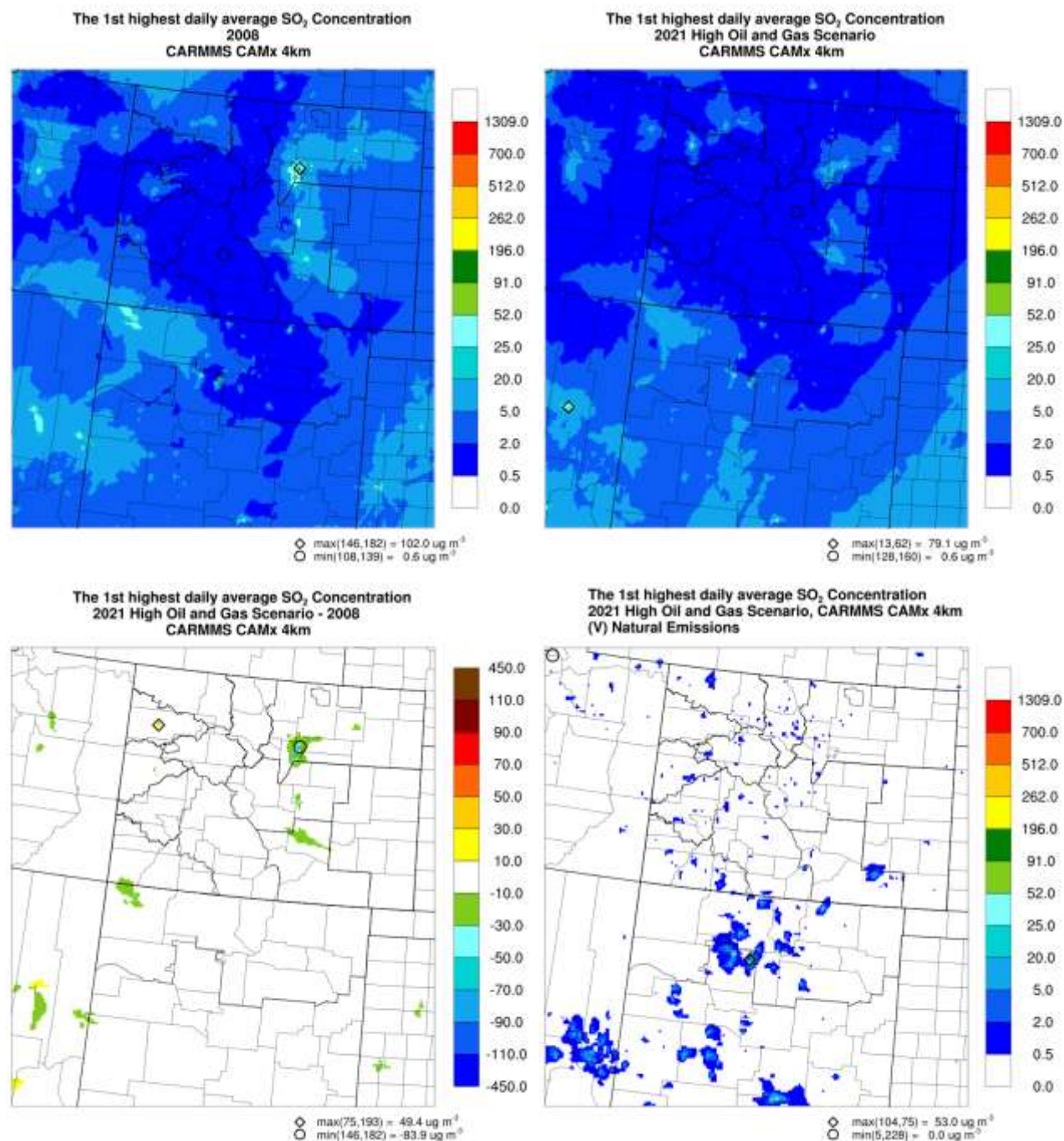


Figure 5-20. 24-hour average SO₂ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 minus 2008 differences (bottom left) and Natural Emissions (bottom right).

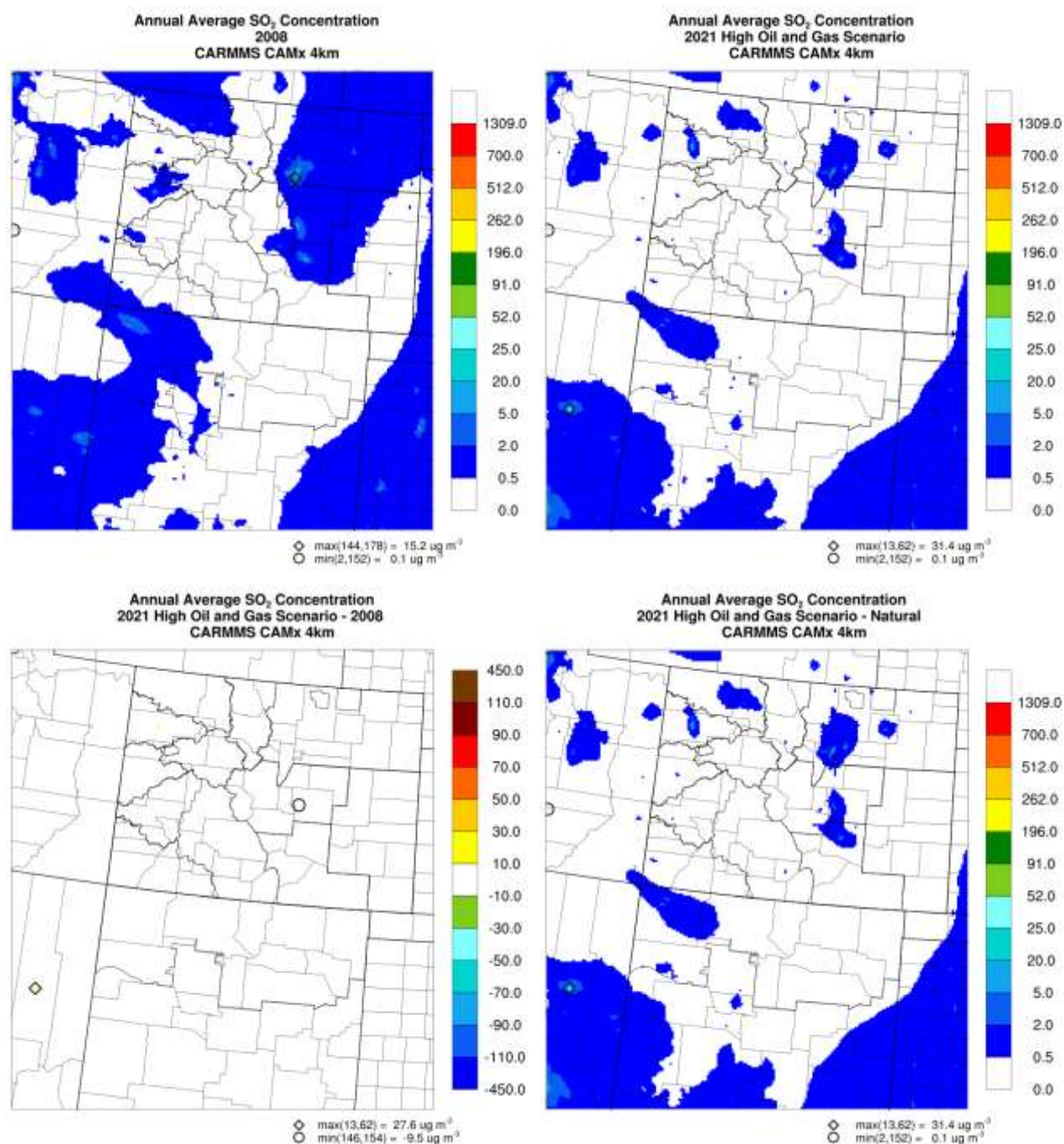


Figure 5-21. Annual average SO₂ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 minus 2008 differences (bottom left) and Natural Emissions (bottom right).

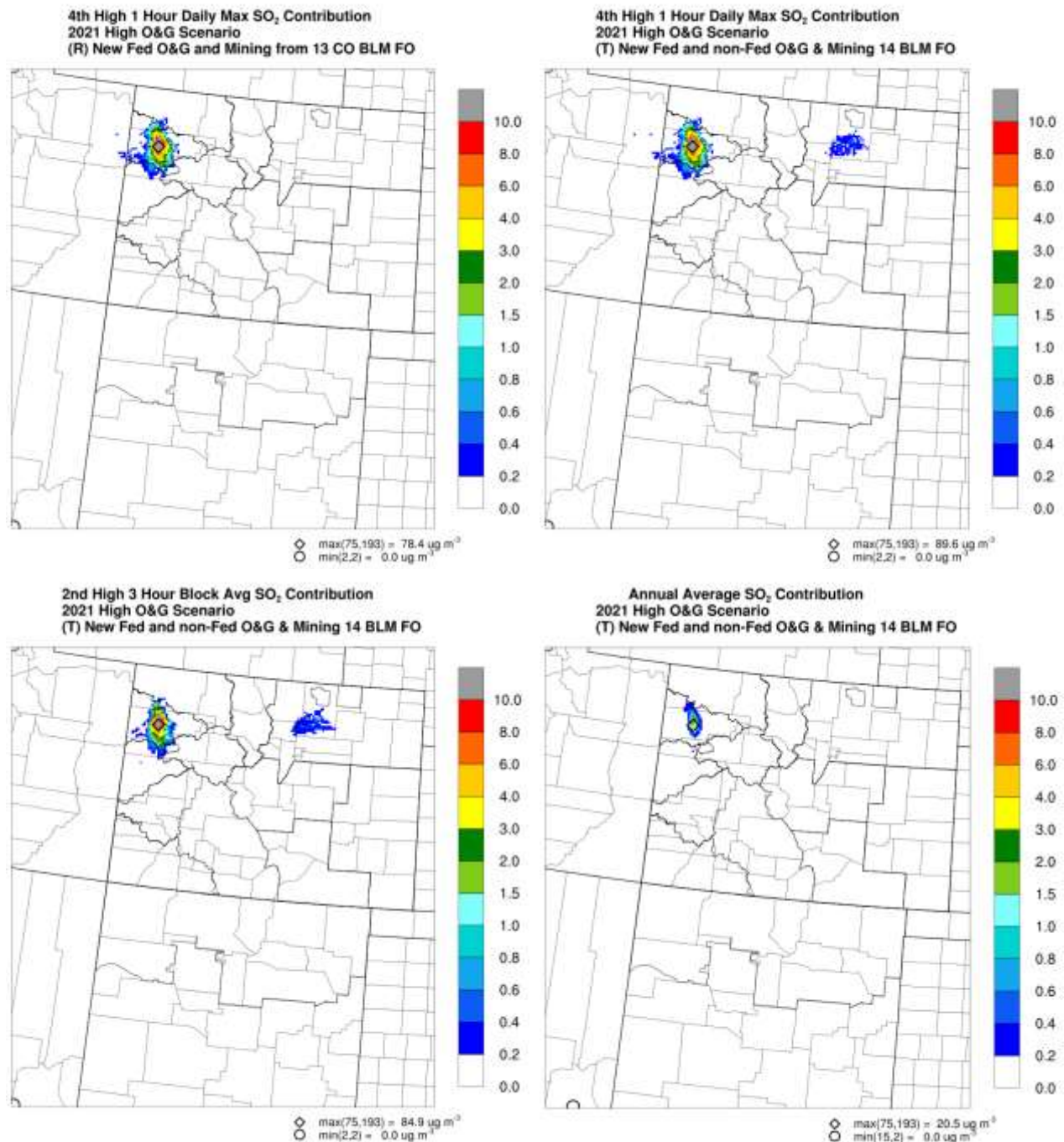


Figure 5-22. Contribution to fourth highest daily maximum hourly SO₂ concentrations due to emissions from new Federal O&G and mining within the 13 CO BLM Planning Areas (top left) and new Federal O&G and mining and non-Federal O&G within the 14 CO/NM BLM Planning Areas (top right). New Federal O&G and mining and new non-Federal O&G from 14 CO/NM BLM Planning Areas contributions to second highest 3-hour SO₂ (bottom left) and annual average SO₂ (bottom right) concentrations for the 2021 High Development Scenario.

5.6.6 NO₂ NAAQS Analysis

Figure 5-23a displays spatial maps of the 98th percentile daily maximum 1-hour NO₂ concentrations for the 2008 Base Case and 2021 High, Low and Medium Development Scenarios with the differences in NO₂ concentrations between the 2021 emissions scenarios and the 2008 Base Case shown in Figure 5-23b. The 1-hour NO₂ NAAQS is 188 µg/m³ (100 ppb) and the tile plots in Figure 5-23a have a cut-point at 188 µg/m³ from red to white. For example, an exceedance of the 1-hour NO₂ NAAQS can be seen in the Denver area in the 2008 Base Case that goes away in the 2021 emission scenarios. In all four scenarios, the highest 1-hour NO₂ concentration occurs on the southern border of the 4 km CARMMS domain that is above the NAAQS. This NO₂ exceedance is due to wildfires so is present in the 2008 Base Case and 2021 scenarios since wildfires were assumed to be unchanged. The fact that the peak 1-hour NO₂ value at this wildfire location is identical for all three 2021 emission scenarios indicates that the 2021 O&G emissions have minimal contributions to it. Outside of this isolated wildfire location in the most southern part of the 4 km CARMMS domain, the 8th highest daily maximum 1-hour NO₂ concentrations only exceeds the 1-hour NO₂ NAAQS at one other location in the 2021 emission scenarios that is the most northeastern corner of Weld County. Although there are Federal O&G emissions increases nearby to this location, they do not occur at this high NO₂ concentration location (Figure 3-10). The fact that there is little reduction in this 1-hour NO₂ peak between the 2021 High and Low Development Scenarios (Figure 5-23b) suggests that the high NO₂ concentration in Weld County is due to other new sources in the 2021 emission scenario and could be attributed to increases in non-Federal oil and gas emissions. As indicated from the plots shown in Section 3.2.1, RGFO area 1 (Weld County is located in RGFO area 1) non-Federal oil and gas emissions for the Low Scenario are actually higher than projected year 2021 non-Federal oil and gas emissions for the High / RFD Scenario.

The differences in 1-hour NO₂ concentrations between the 2008 and 2021 emission scenarios (Figure 5-23b) indicate reductions in the Denver area, slight increases in the O&G development areas (e.g., Uinta, Piceance and D-J Basins) and several isolated occurrences of large increases in northern, eastern and southern Colorado as well as eastern Arizona and New Mexico. As noted above, the cause of the large NO₂ concentration increase at the point in northeast corner of Weld County is not clear but doesn't appear to be due to new Federal O&G emissions. As shown in Figure 3-10, there are some increases in non-Federal oil and gas emissions projected to occur in the vicinity of the predicted Weld County concentrations and are likely contributing to the modeled impacts. The NO₂ increase in Cheyenne County in eastern Colorado does not appear to be due to new O&G emissions since there are no new O&G emissions at that location in the 2021 emission scenarios (Figure 3-10). Upon further review of the year 2011 oil and gas APENs database that was used to define existing O&G emissions inventory, there is a large (> 1,200 TPY) NO₂ emissions source located in the vicinity of the predicted concentrations in Cheyenne County. The increase in 2021 NO₂ concentrations in the southwest corner of Las Animas County in southern Colorado is at the location of new O&G emissions (primarily non-Federal) for the Raton Basin and likely due to O&G emissions, but the resultant total NO₂ concentrations are below the NAAQS. The final two locations of NO₂ concentration increases in eastern Arizona and New Mexico are away from any O&G emissions (Figure 3-10). Since the same increases are seen for the 2021 High, Low and Medium Development Scenarios (Figure 5-23b) then they are not due to Colorado based O&G emissions. They are likely due to EPA's

2020 emission projections used for non-O&G anthropogenic emissions in the 2021 emission scenarios, possibly the deployment of new electrical generating units.

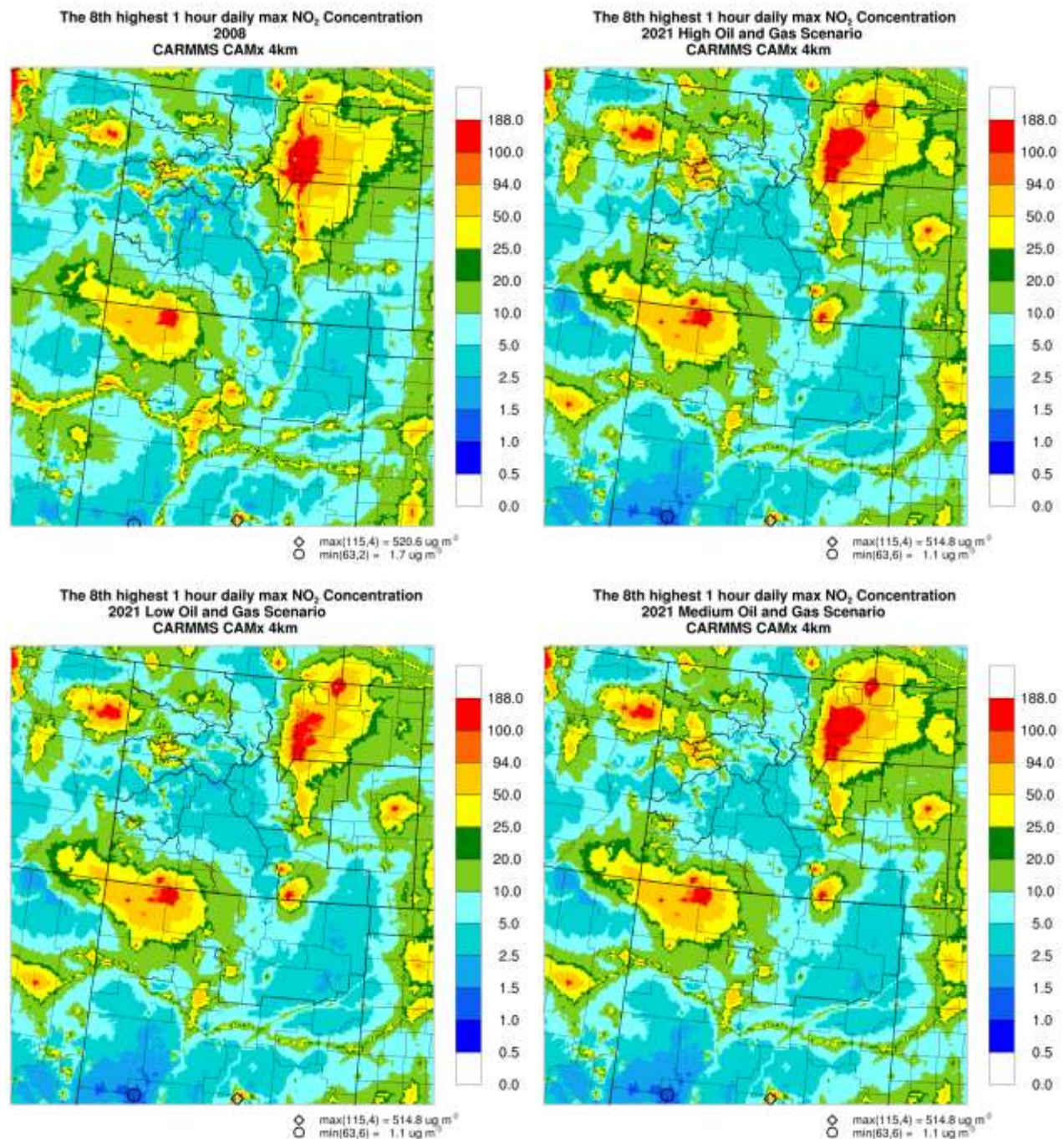


Figure 5-23a. Eighth highest (98th percentile) daily maximum 1-hour average NO₂ concentrations for the 2008 Base Case (top left), 2021 High Development Scenario (top right), 2021 Low Development Scenario (bottom left) and 2021 Medium Development Scenario (bottom right).

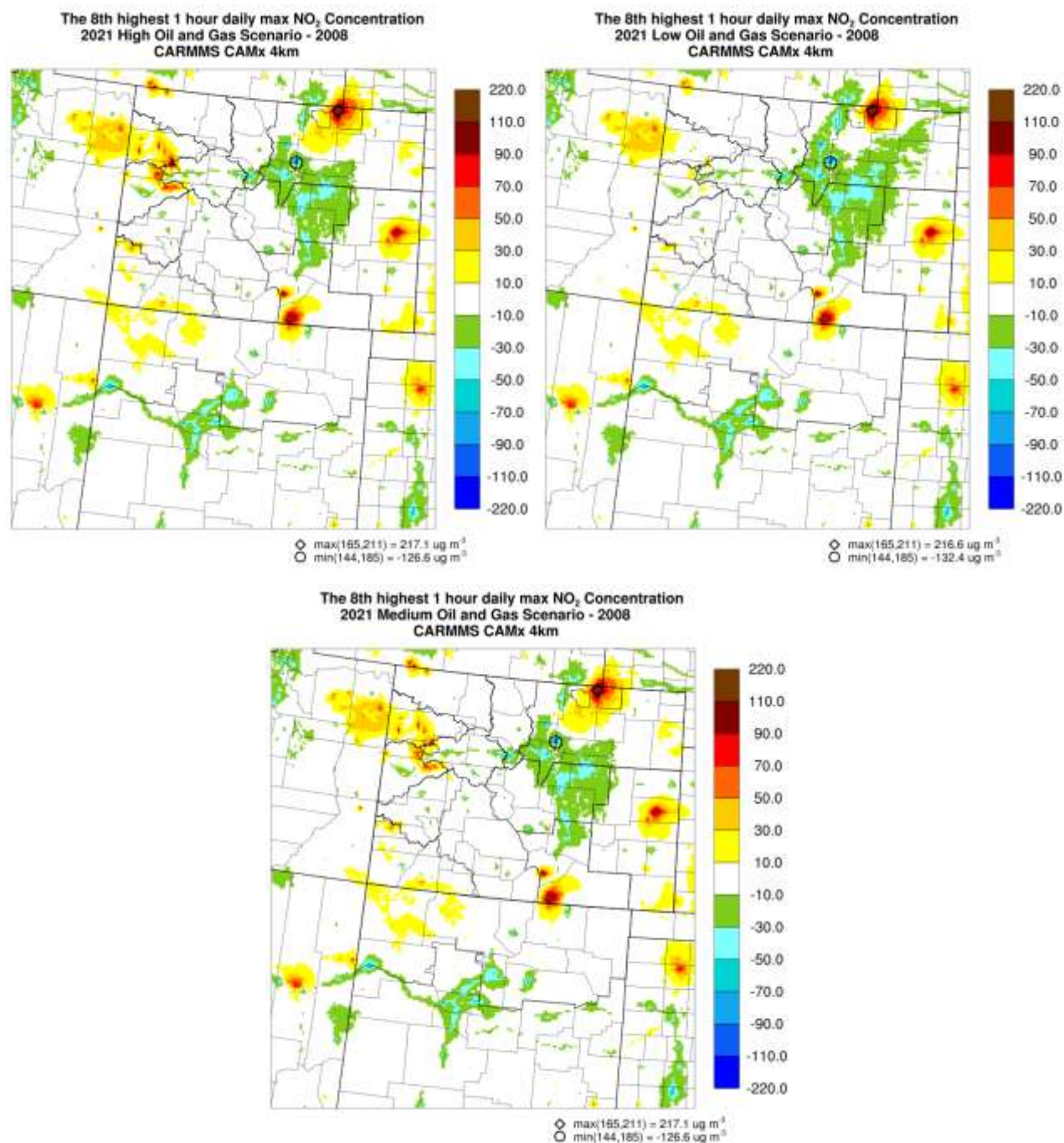


Figure 5-23b. Differences in eighth highest (98th percentile) daily maximum 1-hour average NO₂ concentrations between the 2021 emission scenarios and the 2008 Base Case for the 2021 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

5.7 Source-Receptor Issues

Grid cells were assumed to represent receptors for Class I and sensitive Class I areas if there was any overlap between the grid cell and Class I/II area. Thus, there was the potential for emissions from oil and gas and other sources to be located in the same grid cell/receptor as a Class I/II area. However, in reality new oil and gas sources would not be located in a Class I area so such situations would likely overstate the oil and gas air quality impacts in a Class I area. This section identifies several instances when Class I/II areas are defined very close to new oil and gas emissions resulting air quality impacts that are likely higher than would actually occur.

New Federal O&G development on some of the BLM Planning Areas had relatively higher concentrations impacts at specific Class I areas. For example, new Federal O&G within the TRFO had Maximum annual NO₂ impacts at Mesa Verde Class I area of 1.97 µg/m³ that was 79% of the annual NO₂ PSD Class I increment for the 2021 High Development Scenario. In addition, the visibility impacts at Mesa Verde due to new Federal O&G within TRFO Planning Area for the 2021 High Development Scenario had 35 days with $\Delta dv > 0.5$ and 4 days with $\Delta dv > 1.0$. Recall that grid cells used to represent receptors for Class I and sensitive Class II areas were defined if any portion of the Class I/II area intersected with the grid cell no matter how small the overlap is in order to be conservative (see Section 4.3.2). Figure 5-24 displays the grid cells used to represent the Mesa Verde Class I area along with new Federal O&G emissions from the TRFO Planning Area. The most northern Mesa Verde 4 km grid cell receptor is surrounded by emissions from the TRFO Planning Area with the Class I area covering approximately 20% of the 4 km grid cell so using this 4 km grid cell as a receptor for the Mesa Verde Class I area is probably appropriate. However, there have been other cases when the Class I/II area cover a very small portion of a grid cell that is used as a receptor for a Class I/II area. Perhaps a Class I/II area should be required to have a minimal overlap with a grid cell (e.g., 5%) in order for the grid cell to be considered as a receptor for the Class I/II area.

Another example of relatively larger impacts was seen for TRFO at the South San Juan Class II area (16 days with $\Delta dv > 0.5$). Figure 5-25 compares the grid cells used to represent the South San Juan Wilderness and compares them to new Federal O&G emissions from the TRFO Planning Area. In this case the emissions from the TRFO Planning Area occur in one of the grid cells being used to represent the South San Juan area and the grid cell contains a large portion of the Class II area. It might be beneficial to examine the TRFO O&G emissions to determine whether they are spatially located correctly.

A final example of relatively larger impacts is for new Federal O&G emissions from the NMFFO that had relatively large visibility impacts (210 days with $\Delta dv > 0.5$ and 50 days with $\Delta dv > 1.0$) at the Aztec Ruins Class II area. Aztec Ruins is a small area that is represented by two 4 km grid cells and sits in the middle of the NMFFO Mancos Shale development area. This is shown in Figure 5-26 with the two cells representing Aztec Ruins unlabeled but seen in the middle of the NMFFO O&G emissions.

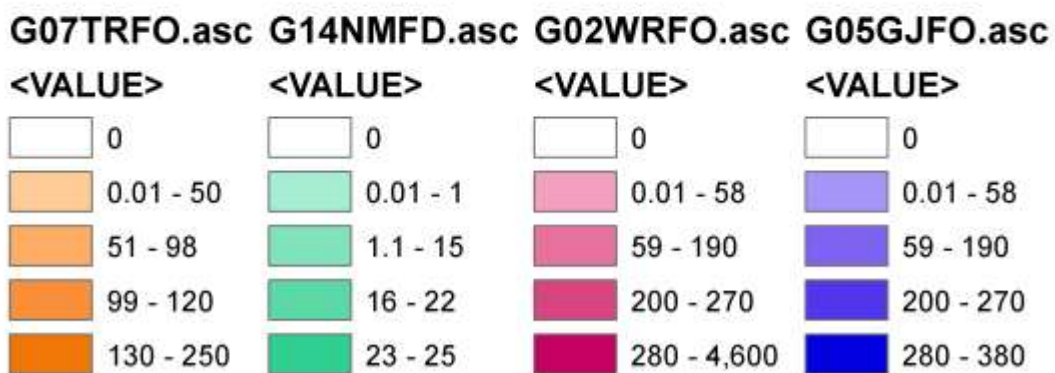
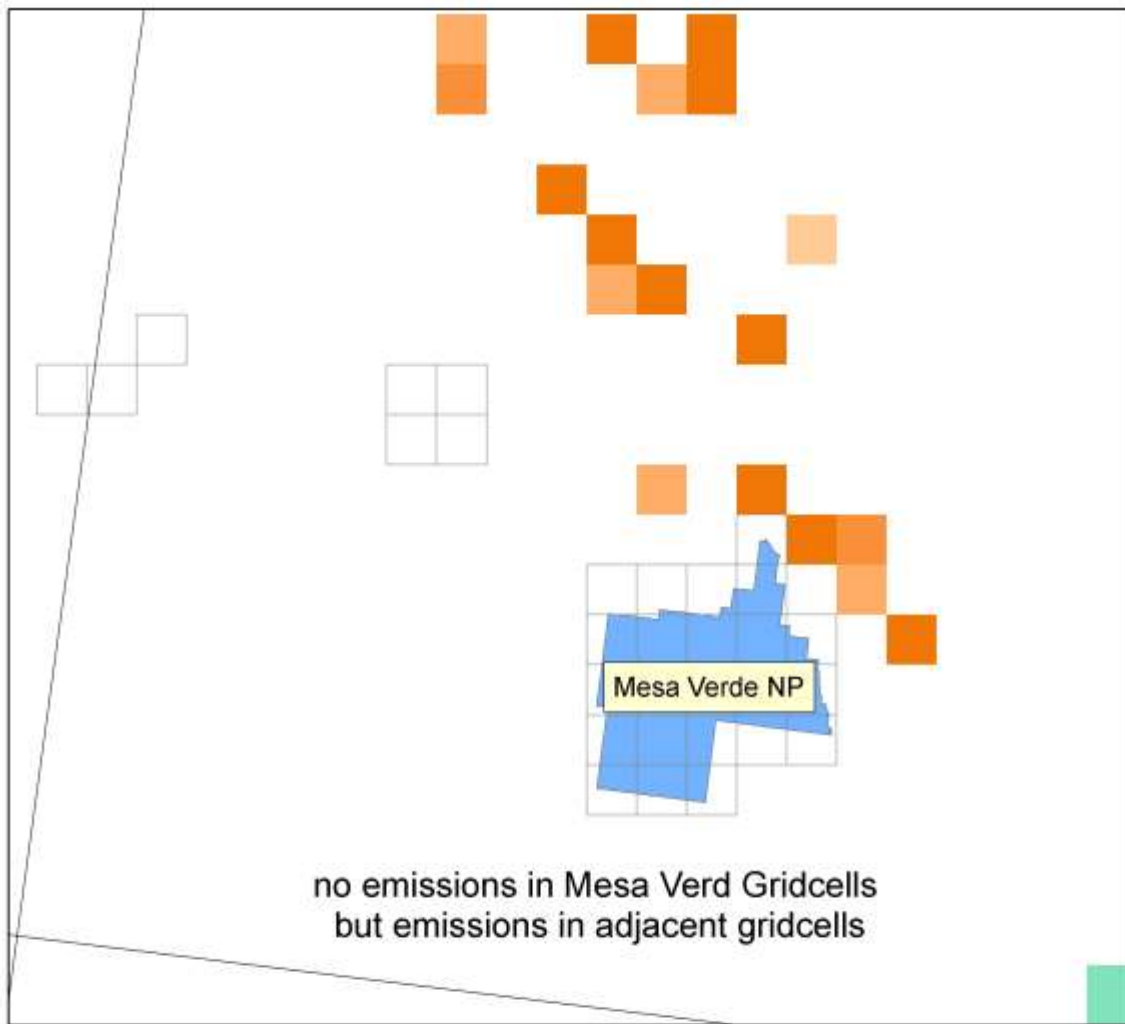
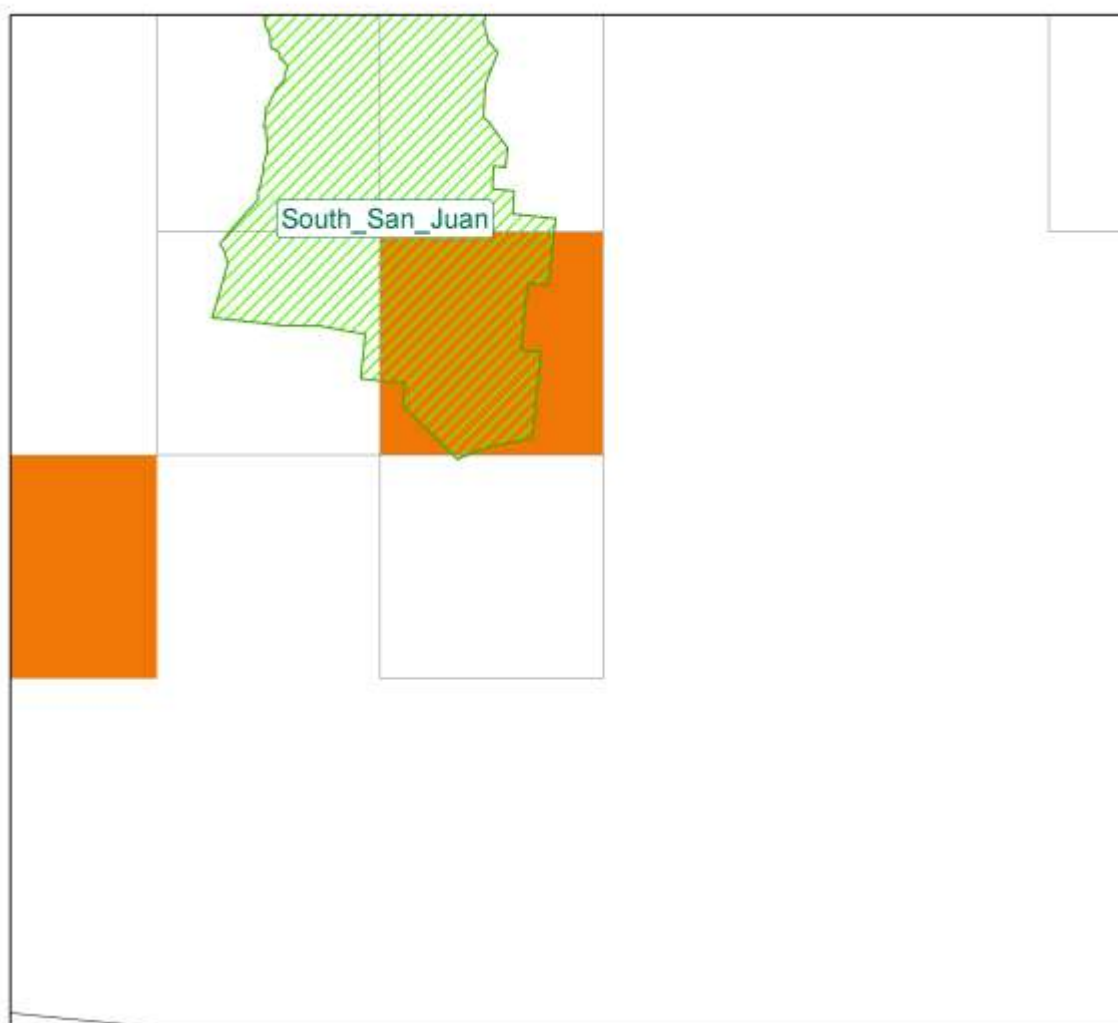
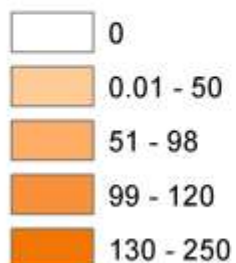


Figure 5-24. Grid cells used to represent the Mesa Verde Class I area with new Federal O&G emissions from the TRFO Planning Area.

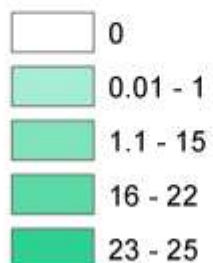


G07TRFO.asc G14NMFD.asc G02WRFO.asc G05GJFO.asc

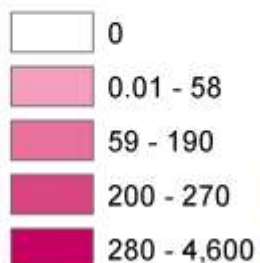
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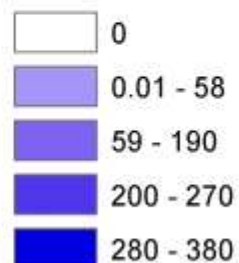
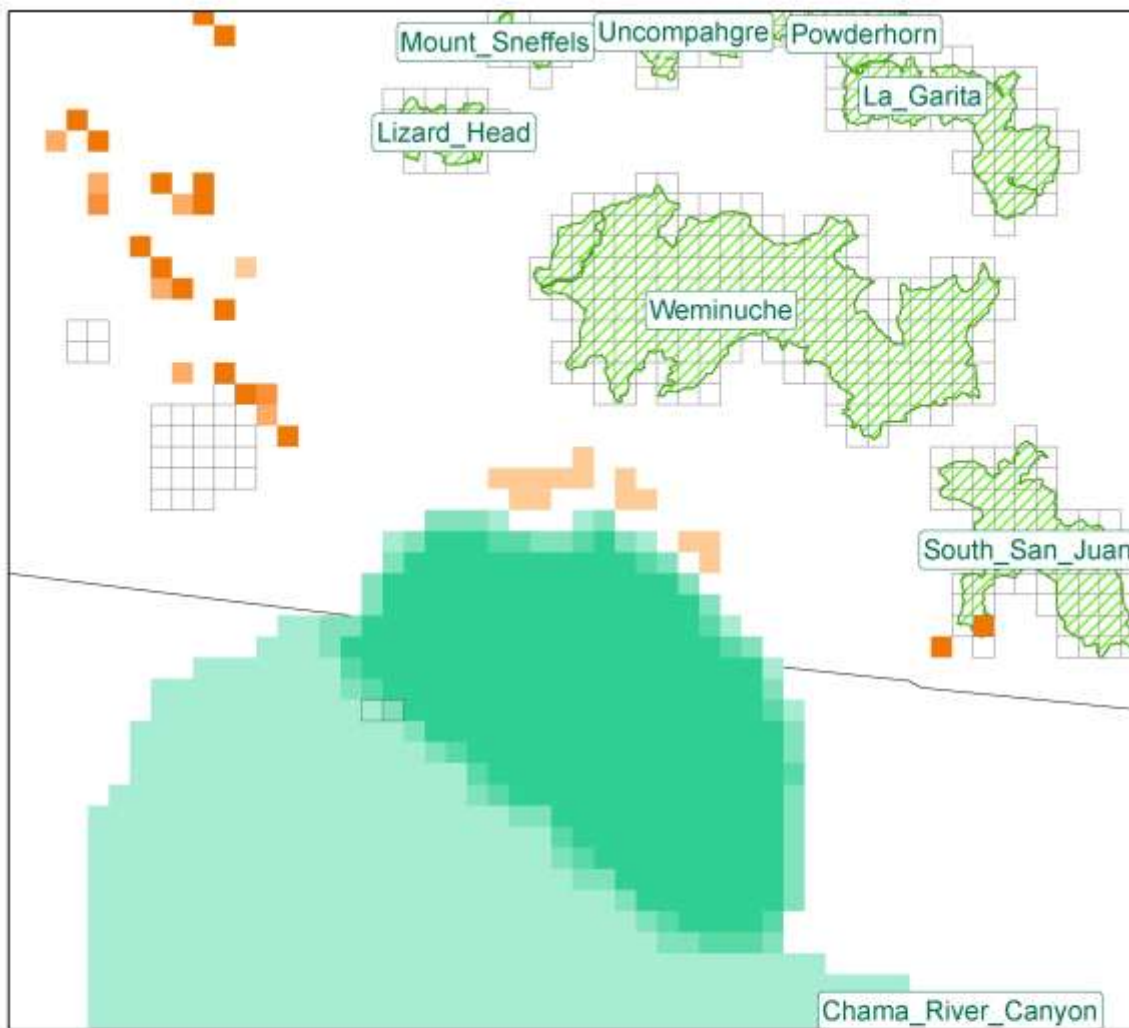


Figure 5-25. Grid cells used to represent the South San Juan Class II area with new Federal O&G emissions from the TRFO Planning Area.



G02WRFO.asc G05GJFO.asc G07TRFO.asc G14NMFD.asc

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59 - 190

200 - 270

280 - 4,600

<VALUE>

0

0.01 - 58

59 - 190

200 - 270

280 - 380

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0

0.01 - 50

51 - 98

99 - 120

130 - 250

<VALUE>

0

0.01 - 1

1.1 - 15

16 - 22

23 - 25

Figure 5-26. Grid cells used to represent the Class I and sensitive Class II areas with new Federal O&G emissions from the NMFFO (Mancos Shale) Planning Area.

6.0 ACRONYMS

ACHD	Allegheny County Health Department
AES	Applied Envirosolutions
AMET	Atmospheric Model Evaluation Tool
APCA	Anthropogenic Precursor Culpability Assessment
APU	Auxiliary Power Units
ARMS	Air Resource Management Study
AQ	Air Quality
AQRV	Air Quality Related Value
AQS	Air Quality System
BC	Boundary Condition
BLM	Bureau of Land Management
CAFOS	Concentrated Animal Feeding Operations
CAMD	Clean Air Markets Division
CAMx	Comprehensive Air-quality Model with extensions
CAPS	Criteria Air Pollutants
CARMMS	Colorado Air Resource Management Modeling Study
CASTNet	Clean Air Status and Trends Network
CAVR	Clean Air Visibility Rule
CB05	Carbon Bond mechanism version 5
CD-C	Continental Divide-Creston
CDPHE	Colorado Department of Health and Environment
CEM	Continuous Emissions Monitor
CENRAP	Central Regional Air Planning Association
CMAQ	Community Multiscale Air Quality modeling system
CMU	Carnegie Mellon University
ConCEPT	Consolidated Community Emissions Processing Tool
CONUS	Continental United States
COSO	BLM Colorado State Office
CRVFO	Colorado River Valley Field Office
CPC	Center for Prediction of Climate
CSAPR	Cross State Air Pollution Rule
CSN	Chemical Speciation Network
DDM	Decoupled Direct Method
DEASCO3	Deterministic and Empirical Assessment of Smoke's Contribution to Ozone
Dv	deciview
ECA	Emissions Control Area
EGU	Electrical Generating Units
EIS	Environmental Impact Statement
EM	Emissions Model
EMS	Emissions Modeling System
EPA	Environmental Protection Agency
EPS	Emissions Processing System
ERG	Eastern Research Group
ESRL	Earth Systems Research Laboratory
FB	Fractional Bias
FE	Fractional Error

FFO	New Mexico BLM Farmington Field Office
FINN	Fire Inventory from NCAR
FLM	Federal Land Manager
FRM	Federal Reference Method
FWS	Fish and Wildlife Service
GCM	Global Chemistry Model
GEOS-Chem	Goddard Earth Observing System (GEOS) global chemistry model
GJFO	Grand Junction Field Office
GSE	Ground Support Equipment
IAD	Impact Assessment Domain
IMPROVE	Interagency Monitoring of Protected Visual Environments
IMWD	Inter-Mountains West Processing Domain
IPAMS	Independent Petroleum Association of the Mountain States
JSFP	Joint Science Fire Program
FO	Kremmling Field Office
LCP	Lambert Conformal Projection
LTO	Landing and Takeoff Operations
LSFO	Little Snake Field Office
LSM	Land Surface Model
MADIS	Meteorological Assimilation Data Ingest System
MATS	Modeled Attainment Test Software
MEGAN	Model of Emissions of Gases and Aerosols in Nature
MM	Meteorological Model
MM5	Version 5 of the Mesoscale Model
MNGE	Mean Normalized Gross Error
MNB	Mean Normalized Bias
MOVES	Motor Vehicle Emissions Simulator
MOZART	Model for Ozone And Related chemical Tracers
NAAQS	National Ambient Air Quality Standard
NADP	National Acid Deposition Program
NCAR	National Center for Atmospheric Research
NCDC	National Climatic Data Center
NDBC	National Data Buoy Center
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NMB	Normalized Mean Bias
NME	Normalized Mean Error
NMED	New Mexico Environmental Department
NMFFO	New Mexico Farmington Field Office
NMIM	National Mobile Inventory Model
NMSO	BLM New Mexico State Office
NOAA	National Oceanic and Atmospheric Administration
NPRI	National Pollutant Release Inventory
NPS	National Park Service
NSPS	New Source Performance Standard
NSR	New Source Review
O&G	Oil and Gas
OA	Organic Aerosol
OSAT	Ozone Source Apportionment Technology

PAVE	Package for Analysis and Visualization
PBL	Planetary Boundary Layer
PGM	Photochemical Grid Model
PiG	Plume-in-Grid
PM	Particulate Matter
PPM	Piecewise Parabolic Method
PSAT	Particulate Source Apportionment Technology
PSD	Prevention of Significant Deterioration
QA	Quality Assurance
QC	Quality Control
RAQC	Regional Air Quality Council
RGFO	Royal Gorge Field Office
RMC	Regional Modeling Center
RMNP	Rocky Mountain National Park
RMP	Resource Management Plan
ROMANS	Rocky Mountain Atmospheric Nitrogen and Sulfur Study
SCC	Source Classification Code
SIP	State Implementation Plan
SMOKE	Sparse Matrix Kernel Emissions modeling system
SOA	Secondary Organic Aerosol
TCEQ	Texas Commission on Environmental Quality
TRFO	Tres Rios Field Office
UAM	Urban Airshed Model
UCR	University of California at Riverside
UFO	Uncompahgre Field Office
UNC	University of North Carolina
UPA	Unpaired Peak Accuracy
USFS	United States Forest Service
USFS-PG	United State Forest Service Pawnee Grasslands
UTSO	BLM Utah State Office
VERDI	Visualization Environment for Rich Data Interpretation
VISTAS	Visibility Improvements for States and Tribal Associations in the Southeast
VMT	Vehicle Miles Traveled
WBD	Wind Blown Dust model
WEA	Western Energy Alliance
WESTUS	Western United States
WRAP	Western Regional Air Partnership
WRFO	White River Field Office
WGA	Western Governors' Association
WRF	Weather Research Forecasting model

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APPENDIX A

2008 WRF Meteorological Modeling for CARMMS

A.1 Introduction

The WRF model performance evaluation was conducted as part of WestJumpAQMS and is documented in a “WRF Application/Evaluation” report (ENVIRON and Alpine, 2012¹). The WestJumpAQMS 2008 WRF model performance evaluation was based on a combination of qualitative and quantitative analyses. The qualitative approach was to compare the spatial distribution of the model estimated monthly total precipitation with the monthly Center for Prediction of Climate (CPC) precipitation analysis using graphical outputs. The quantitative approach was to examine tabulations and graphical displays of the model bias and error for surface wind speed, wind direction, temperature, and mixing ratio (humidity) and compare the performance statistics to benchmarks developed based on a history of meteorological modeling as well as past meteorological model performance evaluations. The statistics were calculated using the publicly available METSTAT evaluation tool, which calculates the statistical performance metrics and can produce time series of predicted and observed meteorological variable and performance statistics. The observed database for winds, temperature, and water mixing ratio that were used in this analysis is from the National Oceanic and Atmospheric Administration (NOAA), Earth System Research Laboratory (ESRL) Meteorological Assimilation Data Ingest System (MADIS). The locations of the MADIS monitoring sites within the 36 and 12 km WRF modeling domains are shown in Figures A-1 and A-2. The rain observations were taken from the NOAA CPC² retrospective rainfall archives.

The WestJumpAQMS 2008 WRF Application/Evaluation report evaluated the WRF surface meteorological parameters using METSTAT across the 36 km CONUS, 12 km WESTUS and 4 km IMWD modeling domains and compared them against meteorological model performance benchmarks. Provided with the WestJumpAQMS WRF Application/Evaluation report was the evaluation of the WRF model performance at each individual surface monitoring site in the inter-mountains western states. The results for all sites in Colorado are available on the WestJumpAQMS website³ with a few examples of the WRF Colorado model performance given below.

¹ http://www.wrapair2.org/pdf/WestJumpAQMS_2008_Annual_WRF_Final_Report_February29_2012.pdf

² <http://www.cpc.ncep.noaa.gov/products/precip/realtime/retro.shtml>

³ <http://www.wrapair2.org/pdf/westjump.wrf.site.co.2012-04-04.pdf>

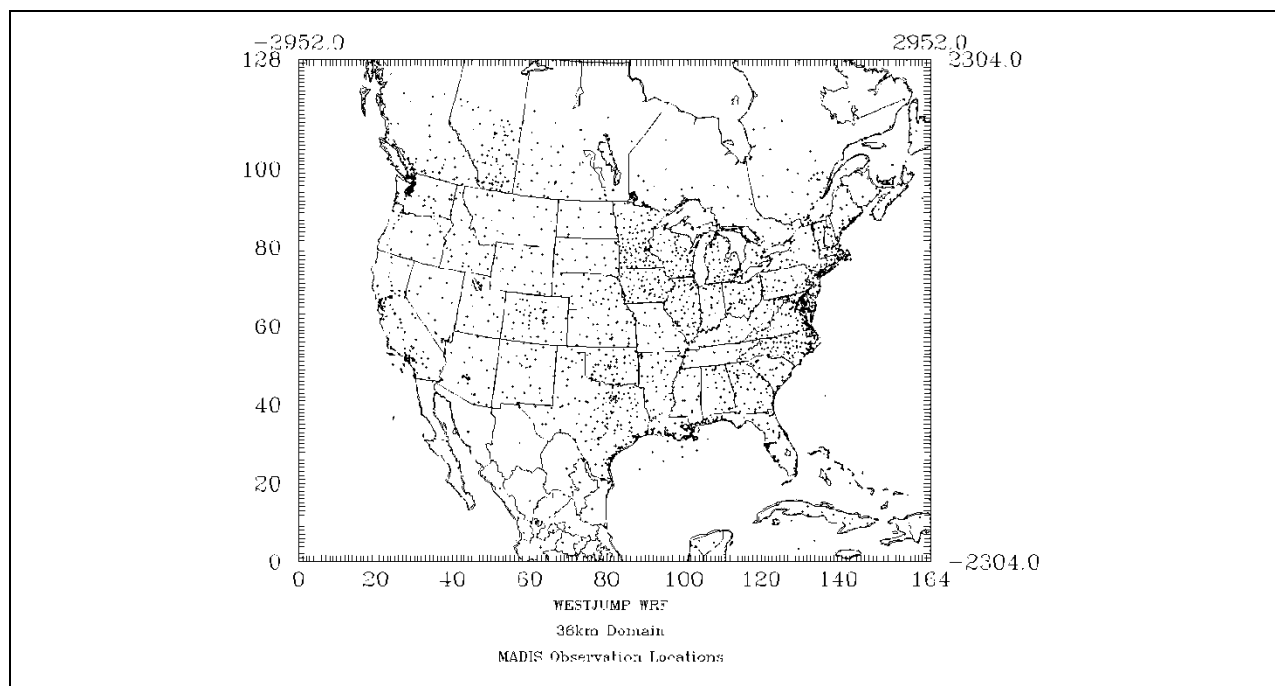


Figure A-1. Locations of MADIS surface meteorological modeling sites within the WestJumpAQMS WRF 36 km modeling domain.

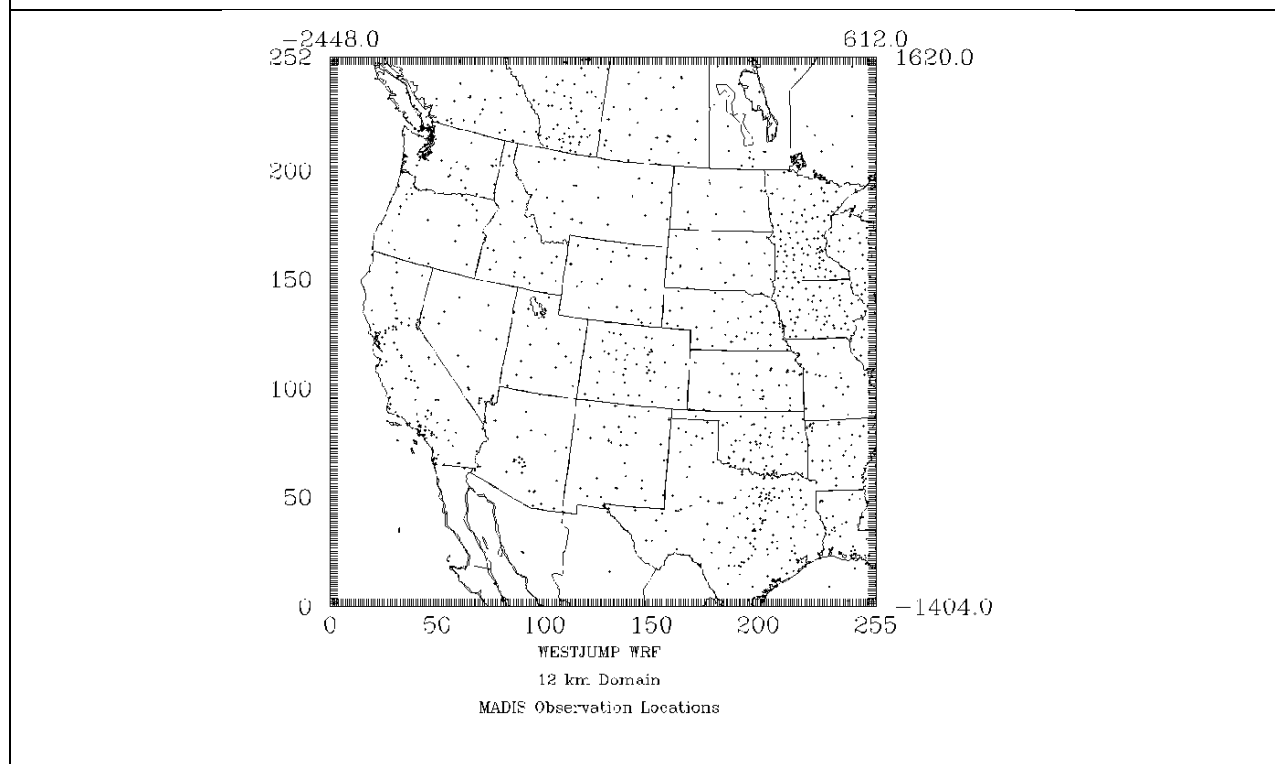


Figure A-2. Locations of MADIS surface meteorological modeling sites within the WestJumpAQMS WRF 12 km modeling domain.

A.2 Meteorological Model Performance Benchmarks

Meteorological model performance evaluation benchmarks have been developed after examining the model performance of ~30 meteorological model simulations that produced “good” air quality model performance, primarily to support ozone SIPs (Emery et al., 2001). The key to the benchmarks is to understand how good or poor the results are relative to other model applications run for the U.S. These meteorological model performance benchmarks include measures of bias and error in surface temperature, wind speed and direction and water vapor mixing ratio. Because the benchmarks were developed primarily for meteorological model simulations to support urban ozone planning they represent model performance under fairly “simple” conditions. That is, usually fairly flat terrain (although sometimes with coastal conditions) with simple meteorological conditions (e.g., stationary high pressure). Meteorological model performance within the complex terrain of the Inter-Mountain West would be expected to be not as good as in these simple conditions. Thus, for some of the meteorological model performance metrics (i.e., temperature) more “complex” performance benchmarks have been developed (Kemball-Cook et al., 2005; McNally, 2009).

The equations for bias, error and Root Mean Squared Error (RMSE) are given below. Table A-1 list the simple and complex meteorological model performance benchmarks that the WRF 2008 simulation model performance was compared against. It is important to emphasize that the benchmarks are not passing/failing grades, rather they are metrics that allow the intercomparison of meteorological model performance.

$$\text{Bias} = \frac{1}{N} \sum_{i=1}^N (P_i - O_i)$$

$$\text{Error} = \frac{1}{N} \sum_{i=1}^N |P_i - O_i|$$

$$\text{RMSE} = \left[\frac{1}{N} \sum_{i=1}^N (P_i - O_i)^2 \right]^{1/2}$$

Table A-1. Simple and complex meteorological model performance benchmarks for surface meteorological model performance evaluation.

Meteorological	Benchmark		
Variable	Simple (Emery et al., 2001)	Complex (McNally, 2009)	Complex (Kemball-Cook et al., 2005)
Temperature Bias	≤±0.5°K	≤±1.0 K	≤±2.0 K
Temperature Error	≤2.0°K	≤3.0 K	≤3.5 K
Mixing Ratio Bias	≤±1.0 g/kg	--	NA
Mixing Ratio Error	≤2.0 g/kg	--	NA
Wind Speed Bias	≤±0.5 m/s	--	≤±1.5 m/s
Wind Speed RMSE	≤2.0 m/s	--	≤2.5 m/s
Wind Direction Bias	≤±10 degrees	--	NA
Wind Direction Error	≤30 degrees	--	≤±55 degrees

A.3 Summary of 2008 WRF Model Performance Evaluation for the CARMMS Region

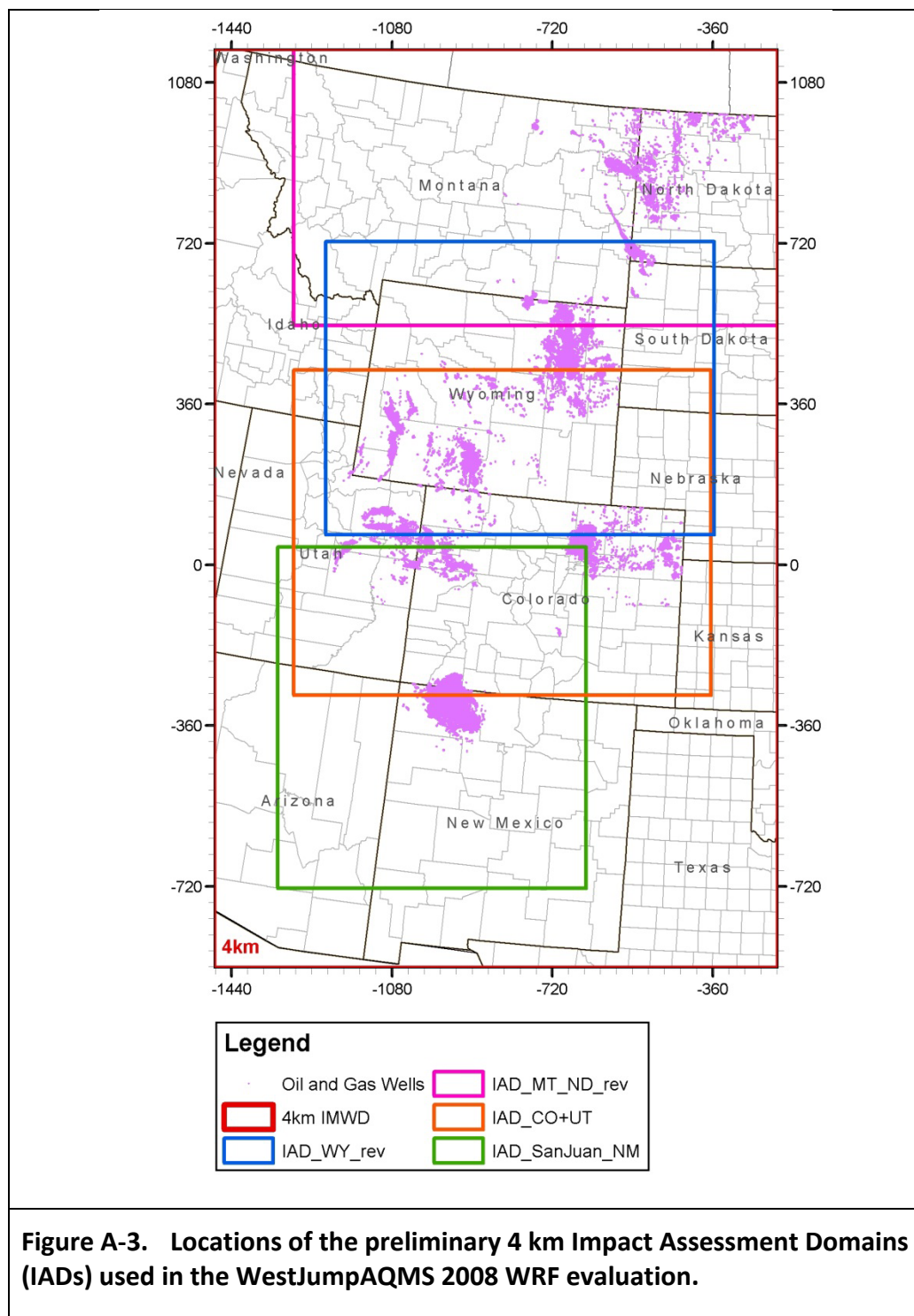
The WestJumpAQMS WRF Application/Evaluation report evaluated WRF across several preliminary Impact Assessment Domains as shown in Figure A-3. The CO_UT 4 km IAD most closely resembles the CARMMS 4 km modeling domain so those results are discussed below. WestJumpAQMS also evaluated WRF's surface meteorological model performance separately for each site in Colorado that is discussed at the end of this section.

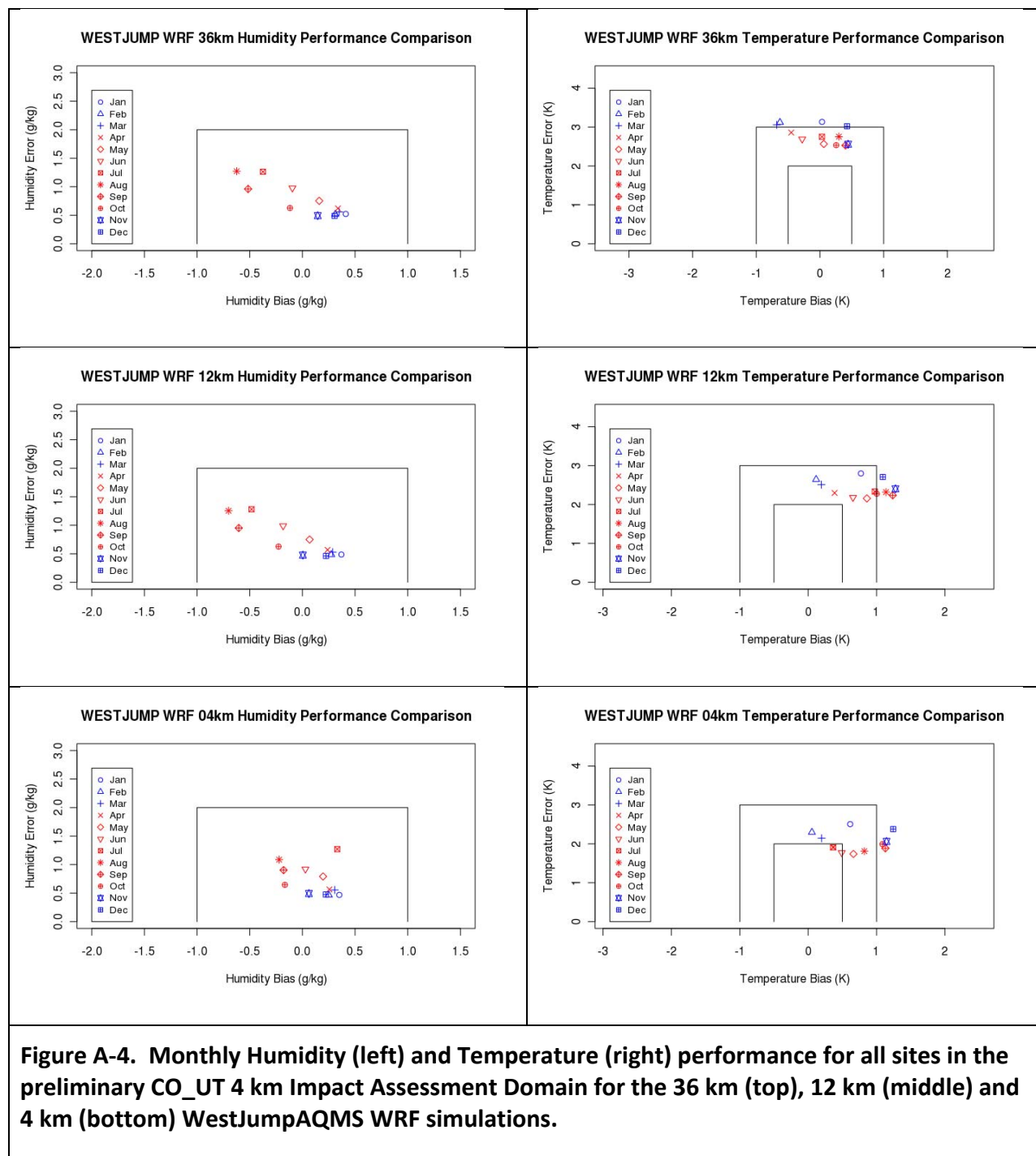
A.3.1 Surface Meteorological Model Performance

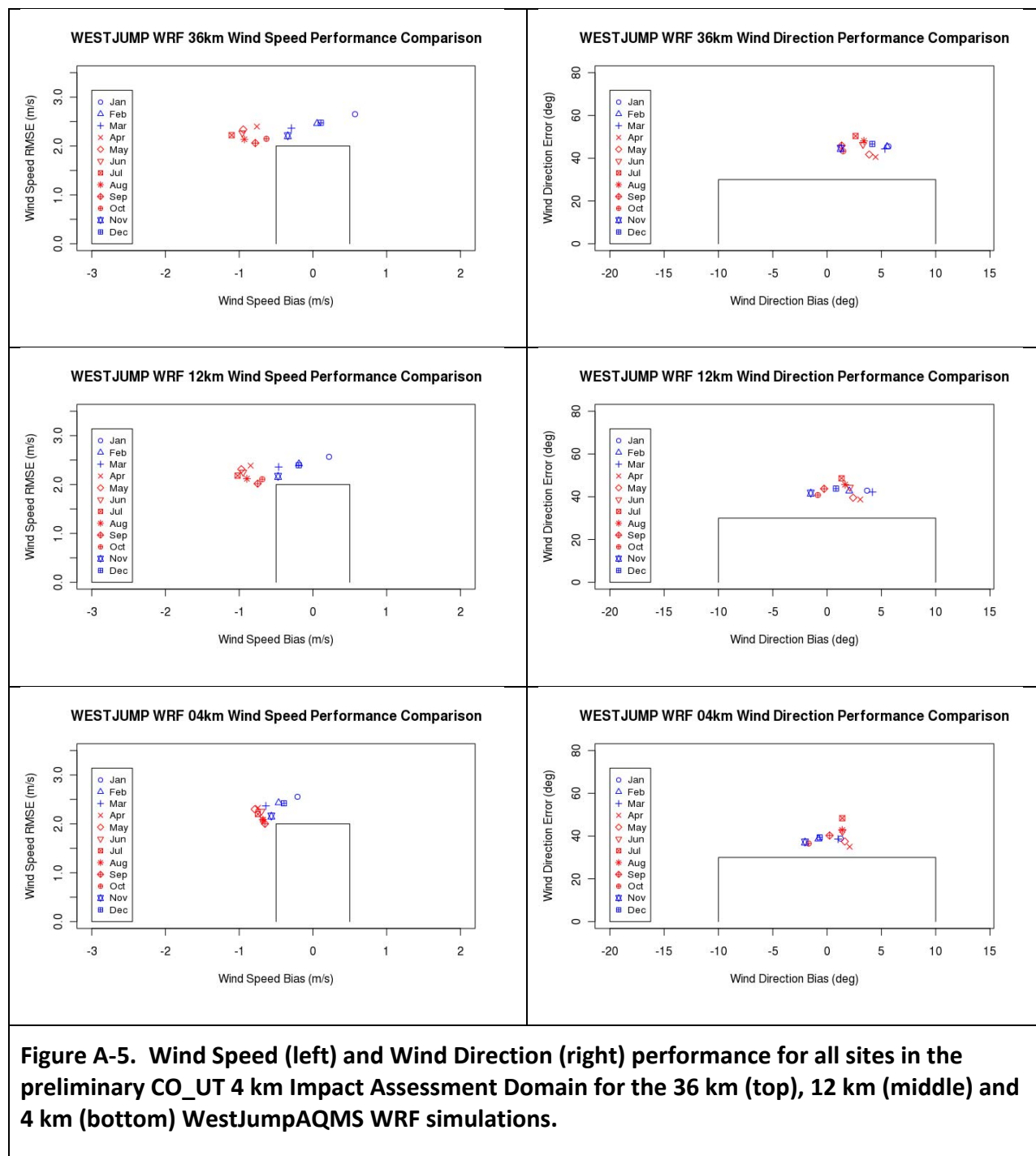
Figure A-4 display soccer plots of monthly humidity (mixing ratio) and temperature model performance within the CO_UT 4 km IAD domain (see Figure A-3) for the WestJumpAQMS 2008 4 km WRF simulation. Soccer plots plot a model's bias versus error and compares them with the model performance benchmark, where in these figures from the WestJumpAQMS WRF Application/Evaluation report (ENVIRON and Alpine, 2012) the Simple and McNally (2009) Complex benchmarks are used (see Table A-1). The WRF 36, 12 and 4 km humidity model performance achieves the Simple Performance Benchmark within the CO_UT 4 km IAD domain (Figure A-4, left). The monthly humidity performance for the WRF 4 km simulation is exhibiting near zero bias and very low error that achieves the Performance Benchmarks.

The WRF 36 km temperature performance has a bias that achieves the $\leq \pm 1.0$ K McNally and $\leq \pm 2.0$ K Kemball-Cook Complex Benchmarks (Figure A-4, right). However, the WRF 12 and 4 km simulation temperature exhibits a positive bias ranging from 0.0 to 1.3 K so that some months fall outside of the McNally but are within the Kemball-Cook Complex Benchmarks. The last four months of the year have a positive bias that is greater than 1.0 K. The WRF 12 and 4 km simulation temperature error falls between the Simple (2.0 K) and Complex 3.0/3.5 K) Benchmarks.

The WRF wind speed bias and error falls between the Simple and Complex benchmarks (Figure A-5, left). WRF exhibits a low wind speed bias across the CO-UT 4 km IAD domain with the negative bias greater for the warm than the cool months. The WRF 12 and 4 km wind direction has a near zero bias that is always within ± 5 degrees that achieves the Simple Benchmark ($\leq \pm 10$ degrees). However, the wind direction error falls between the Simple (≤ 30 degrees) and Complex ≤ 55 degree benchmarks







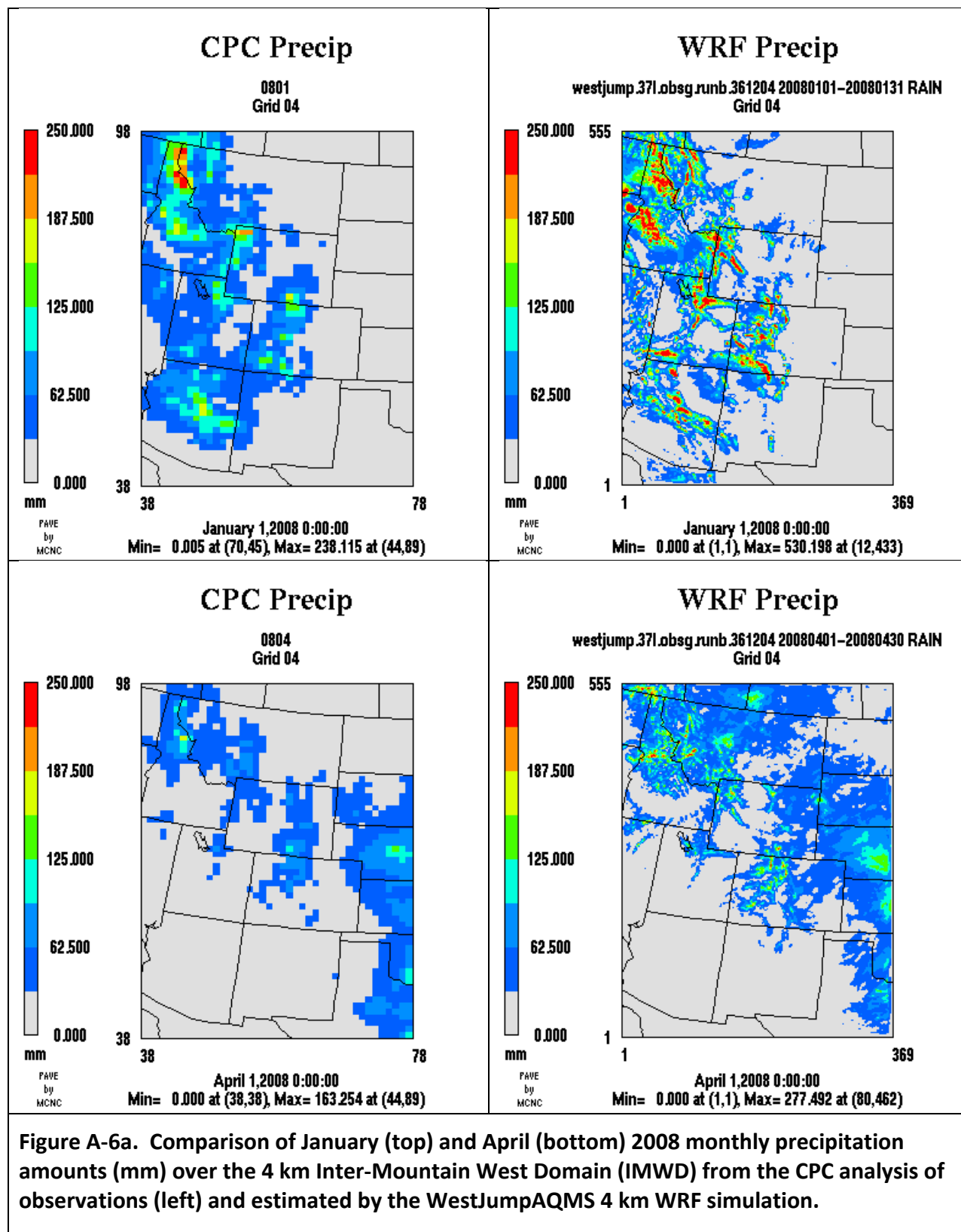
A.3.2 Precipitation Evaluation

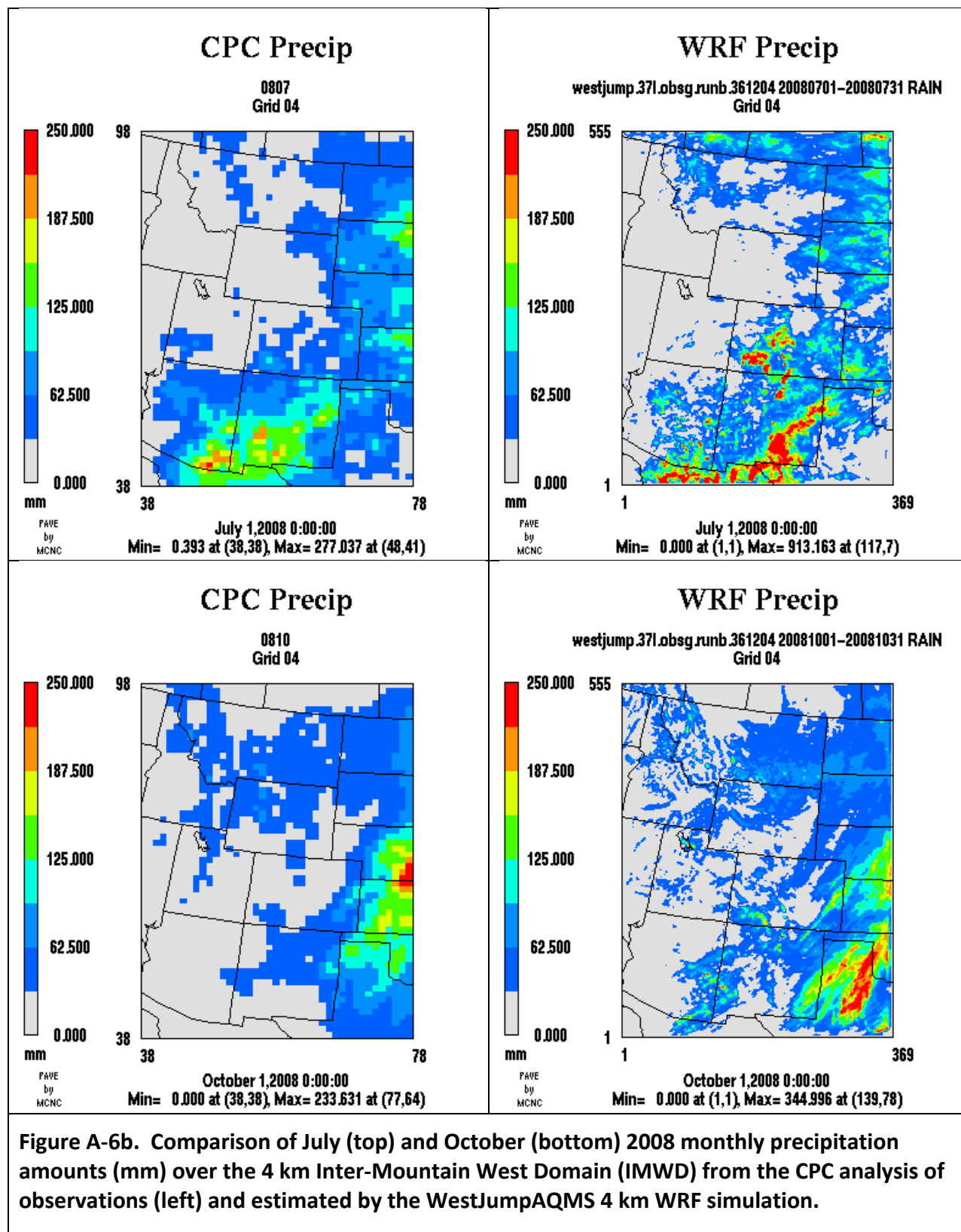
Figure A-6 compares monthly total precipitation across the 4 km IMWD for the CPC analysis fields based on observations, the WRF 4 km estimates and the four months of January, April, July and October (see WestJumpAQMS WRF report for remainder of months, ENVIRON and Alpine, 2012). The much higher resolution in the WRF 4 km precipitation fields is readily apparent compared to the coarser CPC fields and must be accounted for in the interpretation of precipitation model performance. In January 2008, the spatial distribution of the CPC and WRF monthly precipitation fields are very similar with most of it occurring in the western half of the domain and much dryer conditions east of the Front Range. The CPC and WRF estimate similar areas of higher precipitation intensity, although the WRF has smaller areas of higher intensity than the CPC analysis fields due to the higher resolution (Figure A-6a, top).

In April 2008, both the CPC analysis and WRF monthly precipitation exhibit a diagonal northwest to southeast orientation in the precipitation pattern with areas of higher intensity occurring over the Bitterroot Range on the ID-MT border, stretching down along the continental divide and in NB, KS and OK (Figure A-6a, bottom).

In July 2008, the desert southwest summer monsoon is clearly evident in the CPC and WRF precipitation fields with the highest intensity occurring in Arizona and New Mexico (Figure A-6b, top). Higher precipitation amounts are also seen in the high plains in the eastern part of the 4 km IMWD, with the Rocky Mountains in the western part of the 4 km IMWD being much dryer.

In October 2008, both the CPC and WRF have very similar spatial patterns of monthly precipitation with the highest intensity precipitation occurring in Kansas stretching down to OK and TX, with WRF estimating higher intensity in OK/TX than seen in the CPC fields (Figure A-6b, bottom).

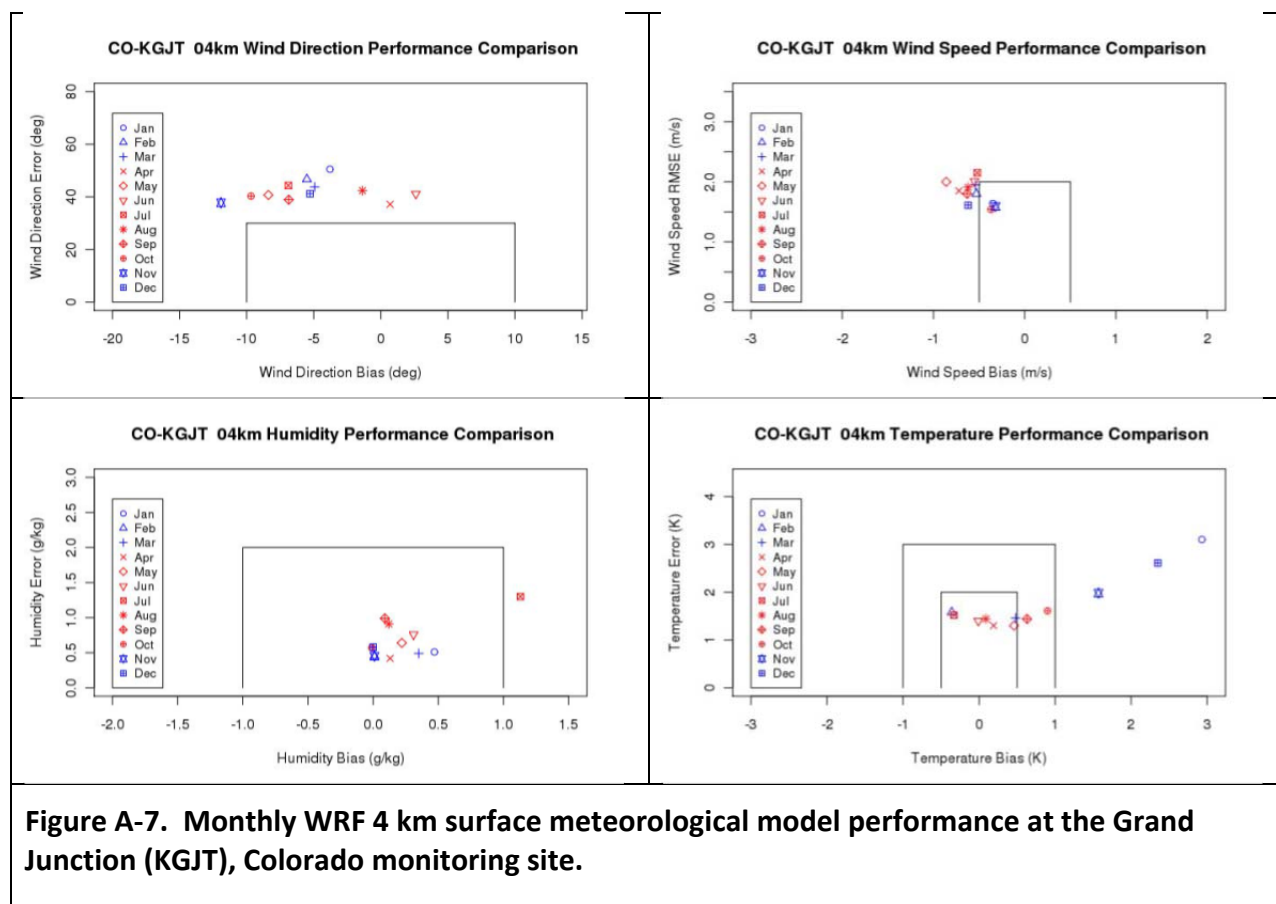




A.3.3 Performance at Individual Monitoring Sites

WestJumpAQMS performed WRF 4 km surface meteorological model performance at individual monitoring sites in Colorado that is posted to its website⁴. The WRF performance varies greatly by site, which may be due in part to each site having its own local influences that cannot be captured by the 4 km WRF average meteorological conditions. For example, Figures A-7 and A-8 displays the WRF 4 km model performance at the Grand Junction (KGJT) and Gunnison (KGUC) Colorado monitoring sites that lie within the BLM Grand Junction and Uncompahgre Field Offices planning areas, respectively. KGJT has a negative wind direction bias that mostly falls within the ± 10 degree performance benchmark and error that falls between the 30 and 55 degree simple and complex benchmarks. KGUC, on the other hand, has much worse wind direction performance with a positive bias that ranges from 0 to 30 degrees and errors of 50 to 80 degrees that fall outside of the benchmark ranges. Similar wind speed performance is seen with mostly an underestimation bias right at the -0.5 m/s simple benchmark but always achieving the complex benchmarks. The humidity benchmarks are almost always achieved at both sites with only July at KGJT falling outside of the benchmark due to being too moist. Different temperature model performance characteristics are seen at the two sites with KGJT achieving the complex benchmark ($\leq \pm 1.0$ K) except for the cold winter months that are too warm by from 1.5 to 3.0 K. Whereas KGUC always achieves the complex benchmark with monthly temperature bias and error clustered around the -0.5 K and 2.0 K simple benchmark bias and error point, except for January that has an overestimation bias of ~ 0.75 K.

⁴ <http://www.wrapair2.org/pdf/westjump.wrf.site.co.2012-04-04.pdf>



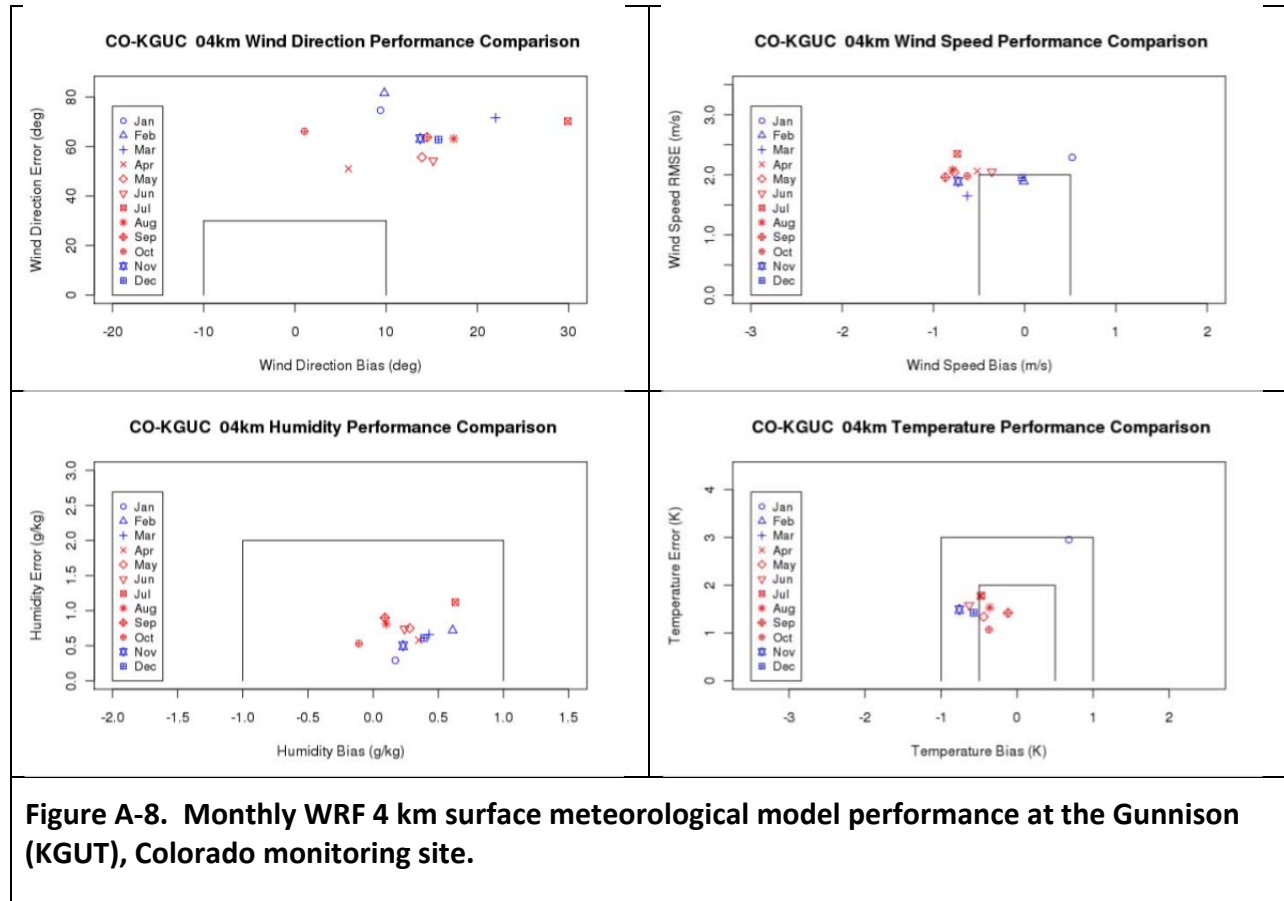


Figure A-8. Monthly WRF 4 km surface meteorological model performance at the Gunnison (KGUC), Colorado monitoring site.

APPENDIX B

2008 CAMX Base Case Model Performance Evaluation

B.1 Introduction

The CAMx PGM was selected for modeling air quality and AQRV impacts due to oil and gas and other activity within the Colorado and northern New Mexico BLM-planning areas. CAMx was selected over CMAQ due to the availability of the CAMx source apportionment tool and the need to obtain separate air quality and air quality related value (AQRV) contributions due to emissions of BLM authorized oil and gas sources in numerous Colorado and northern New Mexico BLM planning areas. CAMx Version 6.1 (V6.1, released April, 2014) was used in the CARMMS future year modeling analysis. However, CAMx V6.0 (September 2013 release) was used for the 2008 Base Case modeling. The CAMx V6.1 future year and CAMx V6.0 2008 Base Case models were configured to obtain identical results, although the CAMx V6.1 future year source apportionment took advantage of a new point source emissions “compact format” feature that greatly reduces the disk space requirements and consequently computational resources for the future year source apportionment modeling.

B.2 CAMx Model Configuration

The CAMx PGM 2008 Base Case modeling was configured as shown in Table B-1 and described below.

Advection and Diffusion Methods: The piecewise parabolic method (PPM) advection solver was used for horizontal transport (Colella and Woodward, 1984) along with the spatially varying (Smagorinsky) horizontal diffusion approach. CAMx will use K-theory for vertical diffusion using the CMAQ-like vertical diffusivities from WRF-CAMx.

Chemical Mechanism: The CB05 gas-phase chemical mechanism was selected for the CAMx 2008 Base Case modeling to be consistent with WestJumpAQMS.

Spin-Up Initialization: A minimum of ten days of model spin up (i.e., using meteorological and emission conditions for December 21-31, 2007) was used to initialize the PGM.

Model Run Strategy: CAMx includes two approaches for using multiple central processing units (CPUs) for multi-processing: (1) Message Passing Interface (MPI) that performs modeling domain decomposition, passes the model solution for each subdomain to different CPUs at each time step, and then reassembles the solution across the whole domain at the end of the time step; and (2) Open Multiprocessing (OpenMP) that uses compiler directives to use multiple CPUs in the model simulation. An optimal configuration of MPI and OpenMP will be determined for the Linux Cluster being used to minimize the model throughput time. After benchmarking several different configurations, the CAMx CARMMS current and future year model simulations were run separately for four quarters using ~10 days of spin-up and using 24 CPUs for each quarter (i.e., using 96 CPUs at once) with 6 MPI domain decomposition and each MPI subdomain was run with 4 OpenMP multi-processing CPUs ($24 = 6 \times 4$).

Boundary Conditions: Boundary conditions (BCs) for the 36 km CONUS domain CAMx simulation were based on output from the Model for OZone And Related chemical Tracers

(MOZART,¹) global chemistry model. BCs for the CARMMS CAMx 2008 4 km based case simulation were based on the WestJumpAQMS CAMx 2008 36/12 km Base Case simulation.

Photolysis Rates: For photolysis rates, CAMx requires a lookup table of photolysis rates as well as gridded albedo/haze/ozone/snow as input. Day-specific ozone column data are based on the Total Ozone Mapping Spectrometer (TOMS) data measured using the satellite-based Ozone Monitoring Instrument (OMI²). Albedo is based on land use data, which includes enhanced albedo values when snow cover is present. For CAMx there is an ancillary snow cover input that is based on WRF output that overrides the land use based albedo input to use an enhanced snow cover albedo value. The Tropospheric Ultraviolet and Visible (TUV) Radiation Model³ photolysis rate processor was used. CAMx is configured to use the in-line TUV to adjust for cloud cover and account for the effects aerosol loadings have on photolysis rates; this latter effect on photolysis may be especially important in adjusting the photolysis rates due to the occurrence of PM concentrations associated with emissions from fires. Note that the same photolysis rates are used in the 2008 Base Case and 2021 future year modeling.

Landuse: Landuse fields were generated based on U.S. Geological Survey (USGS) Geographic Information Retrieval and Analysis System (GIRAS) data⁴. The WRF estimate snow cover data is used to override the USGS land cover categories when snow cover is present.

Meteorological Inputs: The WestJumpAQMS 2008 WRF-derived meteorological fields were processed to generate CAMx meteorological inputs for the CARMMS 4 km domain and 2008 using the WRFCAMx processor.

Plume in Grid: The subgrid-scale Plum-in-Grid module was not used in the CARMMS modeling.

Other Model configuration options are detailed in Table B-1.

¹ <http://www.acd.ucar.edu/wrf-chem/mozart.shtml>

² <http://ozoneaq.gsfc.nasa.gov/>

³ <http://cprm.acd.ucar.edu/Models/TUV/>

⁴ <http://pubs.usgs.gov/ds/2006/240/>

Table B-1. CAMx model configurations for BLM CARMMS 2008 4 km Base Case simulation.

Science Options	Configuration	Details
Model Codes	CAMx V6.0 – May 2013 Release	CAMx V6.1 (April 2014) used in 2021 future year modeling
Horizontal Grid Mesh- Regional Run to generate Boundary Conditions (BC) for the 4 km impact assessment domain	36/12 km	36/12 km run to generate BC for CARMMS 4 km impact assessment domain. 36/12 km run with 2 way grid nesting
36 km grid	148 x 112 cells	36 km CONUS RPO domain
12 km grid	239 x 206 cells	12 km WESTUS domain from WestJumpAQMS domain
Horizontal Grid Mesh- CARMMS Impact Assessment Runs	4 km	216 x 234
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~24- m. Model top at ~19-km above MSL
Grid Interaction	36/12 km two way nesting provide one-way grid nesting to 4 km CARMMS domain	CARMMS 4 km stand-alone domain
Initial Conditions	10 day spin-up	
Boundary Conditions	36 km CONUS domain from MOZART global chemistry model	4 km domain BCs from 36/12 km regional run
Emissions		
Baseline Emissions Processing	SMOKE, MOVES and MEGAN	
Sub-grid-scale Plumes	No Plume-in-Grid for major NO _x sources	
Chemistry		
Gas Phase Chemistry	CB05	
Meteorological Processor	WRFCAMx	
Horizontal Diffusion	Spatially varying	Smagorinsky
Vertical Diffusion	CMAQ-like in WRFCAMx	
Diffusivity Lower Limit	Kz_min = 0.1 to 1.0 m ² /s or 2.0 m ₂ /s	
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	Zhang et al., 2001; 2003
Wet Deposition	CAMx -specific formulation	rain/snow/graupel/virga
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative (EBI) -- Fast Solver	
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update (CAMx)	
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward, 1984
Integration Time Step	Wind speed dependent	~0.1-1 min for 4 km domain

B.3 2008 CAMx Base Case Modeling

WestJumpAQMS performed CAMx modeling using two-way grid nesting on the regional 36 km CONUS and 12 km WESTUS domains using the 2008 Base Case emission scenario to develop boundary conditions (BCs) for the smaller 4 km CARMMS domain. WestJumpAQMS then ran CAMx for the 4 km CARMMS impact assessment domain using 2008 Base Case emissions and BCs from the CAMx 2008 Base Case 36/12 km run.

B.4 Photochemical Model Performance Evaluation

The CAMx 2008 Base Case modeling and model performance evaluation was conducted under the WestJumpAQMS. Originally CARMMS was going to completely rely on the WestJumpAQMS model evaluation of the CARMMS 2008 Base Case simulation and CARMMS did not intend to perform any additional 2008 Base Case modeling or model performance evaluation.

WestJumpAQMS conducted a comprehensive detailed model performance of the CAMx 2008 36/12 km Base Case simulation across the 36 km CONUS and 12 km WESTUS domains, and within each western State for ozone, total PM_{2.5} mass, speciated PM_{2.5}, sulfur and nitrogen wet deposition and for several ozone and PM_{2.5} precursor (e.g., SO₂ and NO_x) and related (e.g., HNO₃) species. Section 4.5.3 of the WestJumpAQMS final report (ENVIRON, Alpine and UNC⁵) presented the evaluation the CARMMS 2008 4 km Base Case simulation across the CARMMS 4 km domain.

B.4.1 February 28, 2014 IAQRT Meeting

The WestJumpAQMS model evaluation results for the CARMMS CAMx 4 km Base Case simulation were presented to the Interagency Air Quality Review Team (IAQRT) on February 28, 2014 at the BLM Colorado State Office (COSO). EPA expressed several concerns regarding the adequacy of the model performance evaluation of the CARMMS 2008 4 km Base Case. In particular they believed that the ozone model performance evaluation should be performed using a 60 ppb observed ozone cut-off instead of the 40 ppb cut-off used by WestJumpAQMS. In addition, they expressed concerns about just calculating monthly model performance statistics across the entire 4 km CARMMS modeling domain.

The evaluation of the CAMx model for the CARMMS 2008 base case simulation produced many more evaluation products than provided in the WestJumpAQMS final report. However, it did not calculate ozone model performed statistics using a 60 ppb observed ozone cut-off threshold as desired by EPA. So we calculated additional ozone model performance statistics using the 60 ppb ozone cut-off threshold. The spreadsheet of monthly ozone bias and error model performance statistics and their comparison with the ozone bias ($\leq \pm 15\%$) and error ($\leq 35\%$) performance goals was updated as follows:

⁵ http://www.wrapair2.org/pdf/WestJumpAQMS_FinRpt_Finalv2.pdf

Ozone Averaging Times

- Hourly
- Daily maximum 8-Hour Ozone Concentrations

Ozone Monitoring Networks

- AQS
- CASTNet

Bias and Error Statistical Metrics

- Fractional Bias and Error
- Normalized Mean Bias and Error
- Mean Normalized Bias and Error

As discussed below, with the exception of some winter months, the monthly ozone statistical performance metrics across the CARMMS 4 km domain still achieved EPA's performance goals even using the 60 ppb cut-off threshold for both averaging times and monitoring networks and three types of bias/error performance metrics.

Regarding more details on the CARMMS CAMx 4 km base case MPE, we packaged up the model performance products in a zipped file that includes many differences types of monthly model performance metrics and species for sites in the CARMMS 4 km modeling domain. Model performance displays include scatter plots and time series plots of predicted and observed concentrations, in addition to a full suite of model performance evaluation statistical metrics, and are provided for each month of 2008 as follows:

- All sites in the CARMMS 4 km domain and all hours/days in a month.
- At each individual site in the CARMMS 4 km domain and all hours/days in a month.
- For each day in 2008 across all sites in the CARMMS 4 km domain.

Model performance displays and statistics are provided for numerous gas-phase (e.g., ozone and NO_x) and particulate matter (PM) species (e.g., SO₄, NO₃, NH₄, EC, OA). EPA specifically requested model performance for ammonia (NH₃) and ammonium (NH₄). However, there were no routine NH₃ measurements available in 2008 and NH₄ was just measured at the CSN network. Although we also evaluated CAMx against derived ammonium (NH₄d) at IMPROVE sites that is obtained using the IMPROVE SO₄ and NO₃ measurements and assuming they are completely neutralized by NH₄; note this will overstate actual NH₄ values because SO₄ is not always neutralized and both SO₄ and NO₃ can be neutralized by other cations besides NH₄.

The detailed model performance displays and metrics for the CARMMS CAMx 2008 base case simulation is contained in the zipped file "CARMMS_2008_4km_MPE_Details.zip" that contains over 4,500 separate model performance displays and is larger than 70 Mb.

Below we present the WestJumpAQMS evaluation of the CARMMS 2008 Base Case simulation across the 4 km CARMMS domain with the addition of the ozone metrics using the 60 ppb cut-off concentrations discussed above. However, we do not present the evaluation down to the individual site as the amount of information is too overwhelming.

B.4.2 Observed Monitoring Networks

The following routine air quality measurement data networks were used in the CAMx model performance evaluation:

EPA AQS Surface Air Quality Data: Data files containing hourly-averaged concentration measurements at a wide variety of state and EPA monitoring networks are available in the Air Quality System (AQS⁶) database throughout the U.S. These data sets will be reformatted for use in the model evaluation software tools. There are several types of networks within the AQS that measure different species. The standard hourly AQS AIRS monitoring stations typically measure hourly ozone, NO₂, NO_x and CO concentration and there are thousands of sites across the U.S. The Federal Reference Method (FRM) network measures 24-hour total PM_{2.5} mass concentrations using a 1:3 day sampling frequency, with some sites operating on an everyday frequency. The Chemical Speciation Network (CSN) measures speciated PM_{2.5} concentrations including SO₄, NO₃, NH₄, EC, OC and elements at 24-hour averaging time period using a 1:3 or 1:6 day sampling frequency.

IMPROVE Monitoring Network: The Interagency Monitoring of Protected Visual Environments (IMPROVE⁷) network collects 24-hour average PM_{2.5} and PM₁₀ mass and speciated PM_{2.5} concentrations (with the exception of ammonium) using a 1:3 day sampling frequency. IMPROVE monitoring sites are mainly located at more rural Class I area sites that correspond to specific National Parks and Wilderness Areas across the U.S., with most of the sites located in the western U.S. Although there are also some IMPROVE protocol sites that can be more urban-oriented.

CASTNet Monitoring Network: The Clean Air Status and Trends Network (CASTNet⁸) operates approximately 80 monitoring sites in mainly rural areas across the U.S. CASTNet sites typically collected hourly ozone, temperature, wind speed and direction, sigma theta, solar radiation, relative humidity, precipitation and surface wetness. CASTNet also collects weekly (Tuesday to Tuesday) samples of speciated PM_{2.5} sulfate, nitrate, ammonium and other relevant ions and weekly gaseous SO₂ and nitric acid (HNO₃).

NADP Network: The National Acid Deposition Program (NADP⁹) collects weekly samples of SO₄, NO₃ and NH₄ in precipitation (wet deposition) in their National Trends Network (NTN) at over a 100 sites across the U.S. that are mainly located in rural areas away from big cities and major point sources. Seven NADP sites also collect daily wet deposition measurements (AIRMN) when precipitation occurs. Over 20 of the NADP sites also collect weekly mercury (MDN)

⁶ <http://www.epa.gov/ttn/airs/airsaqs/aqsweb/>

⁷ <http://vista.cira.colostate.edu/IMPROVE/>

⁸ <http://java.epa.gov/castnet/>

⁹ <http://nadp.sws.uiuc.edu/NADP/>

samples. Note that observed sulfate and nitrate dry deposition can be estimated at CASTNet sites using concentrations and a micro-meteorological model that produces a deposition velocity. But these are not true observations, but model estimates of dry deposition flux using observed atmospheric concentrations and meteorological variables and a micro-meteorological deposition model.

B.4.3 Model Performance Goals

Over two decades ago EPA developed PGM ozone model performance goals that are listed in Table B-2 (EPA, 1991). During the regional haze RPO process, additional model performance goals and criteria were developed for PM species (Boylan, 2004; Morris et al., 2009c,d) that are listed in Table B-3. Note that the EPA 1991 ozone model performance goals were applied to the mean normalized bias (MNB) and mean normalized gross error (MNGE) model performance statistics that are calculated for all predicted and observed hourly ozone pairs matched by time and location for which the observed hourly ozone is above a threshold, with a 60 ppb threshold recommended. However, the 60 ppb ozone cut-off was selected for urban ozone modeling of areas with high ozone concentrations addressing the 1-hour ozone NAAQS of 124 ppb. Ozone is much lower these days so an observed ozone cut-off threshold concentration of 40 ppb was used for calculating the MNB and MNGE ozone statistics in addition to the 60 ppb cut-off value. For PM performance statistics, the Fractional Bias (FB) and Fractional Error (FE) bias/error performance metrics are compared against goals and criteria developed during the Regional Planning Organizations (RPOs) modeling to support the Regional Haze Rule (Boylan, 2004; Morris et al., 2009c,d). Table B-4 lists the definitions of the model performance statistical metrics.

More recently, EPA compiled and interpreted the model performance from 69 PGM modeling studies in the peer-reviewed literature between 2006 and March 2012 and developed recommendations on what should be reported in a model performance evaluation (Simon, Baker and Phillips, 2012). Although these recommendations are not official EPA guidance, they are useful for consideration in the BLM CARMMS model performance evaluation:

- PGM MPE studies should at a minimum report the Mean Bias (MB) and Mean Error (ME or RMSE), and Normalized Mean Bias (NMB) and Normalized Mean Error (NME) and/or Fractional Bias (FB) and Fractional Error (FE). Both the MNB and FB are symmetric around zero with the FB bounded by -200% to +200%.
- Use of the Mean Normalized Bias (MNB) and Gross Error (MNGE) is not encouraged because they are skewed toward low observed concentrations and can be misinterpreted due to the lack of symmetry around zero.
- The model evaluation statistics should be calculated for the highest resolution temporal resolution available and for important regulatory averaging times (e.g., daily maximum 8-hour ozone).
- It is important to report processing steps in the model evaluation and how the predicted and observed data were paired and whether data are spatially/temporally averaged before the statistics are calculated.

- Predicted values should be taken from the grid cell that contains the monitoring site, although bilinear interpolation to the monitoring site point can be used for higher resolution modeling (< 12 km).
- PM_{2.5} should also be evaluated separately for each major component species (e.g., SO₄, NO₃, NH₄, EC, OA and OPM_{2.5}).
- Evaluation should be performed for subsets of the data including, high observed concentrations (e.g., ozone > 60 ppb¹⁰), by subregions and by season or month.
- Evaluation should include more than just ozone and PM_{2.5}, such as SO₂, NO₂ and CO.
- Spatial displays should be used in the model evaluation to evaluate model predictions away from the monitoring sites. Time series of predicted and observed concentrations at a monitoring site should also be used.
- It is necessary to understand measurement artifacts in order to make meaningful interpretation of the model performance evaluation.

Given these recommendations we will stress the FB and FE and NMB and NME measures of bias and error over the MNB and MNGE.

Table B-2. Hourly ozone model performance goals from EPA's 1991 PGM modeling guidance.

Goal	Metric	Definition	Comment
≤±20%	Unpaired Peak Accuracy (UPA)	$\frac{P - O_{peak}}{O_{peak}}$	Compare highest predicted and observed daily maximum hourly ozone concentrations unmatched by location and hour but matched by day.
≤±15%	Mean Normalized Bias (MNB)	$\frac{1}{N} \sum_{i=1}^N \frac{(P_i - O_i)}{O_i}$	Predicted and observed hourly ozone concentrations matched by time and location when observed ozone is 60 ppb or greater. Use a 40 ppb cut-off in CARMMS.
≤35%	Mean Normalized Gross Error (MNGE)	$\frac{1}{N} \sum_{i=1}^N \frac{ P_i - O_i }{O_i}$	Predicted and observed hourly ozone concentrations matched by time and location when observed ozone is 60 ppb or greater. Use a 40 ppb cut-off in CARMMS.

Table B-3. Ozone and PM model performance goals and criteria for bias and error (Boylan, 2004; Morris et al., 2009c,d).

Bias	Error	Comment
≤±15%	≤35%	Ozone model performance Goal from the 1991 guidance that would be considered very good model performance for PM species (EPA, 1991).
≤±30%	≤50%	PM model performance Goal, considered good PM performance (Boylan, 2004).
≤±60%	≤75%	PM model performance Criteria, considered average PM performance. Exceeding this level of performance for PM species with significant mass may be cause for concern (Boylan, 2004).

¹⁰ Note that because of the low ozone concentrations in the Montana/Dakotas the Simon, Baker and Phillips (2012) 60 ppb threshold recommendation should be lowered to 40 ppb.

Table B-4. Definition of model performance evaluation statistical measures used to evaluate PGMs in the past.

Statistical Measure	Mathematical Expression	Notes
Accuracy of paired peak (AP)	$\frac{P - O_{peak}}{O_{peak}}$	Comparison of the peak observed value (O_{peak}) with the predicted value at same time and location
Coefficient of determination (r^2)	$\frac{\left[\sum_{i=1}^N (P_i - \bar{P})(O_i - \bar{O}) \right]^2}{\sum_{i=1}^N (P_i - \bar{P})^2 \sum_{i=1}^N (O_i - \bar{O})^2}$	P_i = prediction at time and location i ; O_i = observation at time and location i ; \bar{P} = arithmetic average of P_i , $i=1,2,\dots,N$; \bar{O} = arithmetic average of O_i , $i=1,2,\dots,N$
Normalized Mean Error (NME)	$\frac{\sum_{i=1}^N P_i - O_i }{\sum_{i=1}^N O_i}$	Reported as %
Root Mean Squared Error (RMSE)	$\left[\frac{1}{N} \sum_{i=1}^N (P_i - O_i)^2 \right]^{1/2}$	Reported as %
Fractional Gross Error (FE)	$\frac{2}{N} \sum_{i=1}^N \left \frac{P_i - O_i}{P_i + O_i} \right $	Reported as % and bounded by 0% to 200%
Mean Absolute Gross Error (MAGE)	$\frac{1}{N} \sum_{i=1}^N P_i - O_i $	Reported as concentration (e.g., $\mu\text{g}/\text{m}^3$)
Mean Normalized Gross Error (MNGE)	$\frac{1}{N} \sum_{i=1}^N \frac{ P_i - O_i }{O_i}$	Reported as %
Mean Bias (MB)	$\frac{1}{N} \sum_{i=1}^N (P_i - O_i)$	Reported as concentration (e.g., $\mu\text{g}/\text{m}^3$)
Mean Normalized Bias (MNB)	$\frac{1}{N} \sum_{i=1}^N \frac{(P_i - O_i)}{O_i}$	Reported as %
Mean Fractionalized Bias (Fractional Bias, FB)	$\frac{2}{N} \sum_{i=1}^N \left(\frac{P_i - O_i}{P_i + O_i} \right)$	Reported as %, bounded by -200% to +200%
Normalized Mean Bias (NMB)	$\frac{\sum_{i=1}^N (P_i - O_i)}{\sum_{i=1}^N O_i}$	Reported as %
Bias Factor (BF)	$\frac{1}{N} \sum_{i=1}^N \left(\frac{P_i}{O_i} \right)$	Reported as BF:1 or 1: BF or in fractional notation (BF/1 or 1/BF).

B.4.4 Model Performance Evaluation Approach

The WestJumpAQMS CAMx 2008 base case model performance evaluation focused on evaluating the model for its primary intended purpose, estimating the air quality and AQRV impacts within the 4 km CARMMS modeling domain. Based on EPA modeling guidance (EPA, 1991; 2007), the recommendations of Simon, Baker and Philips (2012) and previous studies, the WestJumpAQMS CAMx model performance evaluation included the following:

- The PGM should be evaluated across all relevant species for which observations are available, including ozone, NO, NO₂, NO_x, HNO₃, SO₂, PM_{2.5}, PM₁₀, speciated PM_{2.5} (SO₄, NO₃, NH₄, EC, OA and OPM_{2.5}) and wet sulfur and nitrogen deposition.
- Numerous statistical performance measures should be calculated (Table B-4) and reported following the recommendations of Simon, Baker and Phillips (2012)
- The native sampling frequency of the observations will be used in the evaluation, along with important regulatory averaging times (e.g., daily maximum 8-hour ozone, annual PM_{2.5} and annual wet deposition).
- The PGM evaluation should also include geographic, temporal and concentration stratifications.
- The PGM results should be more thoroughly evaluated for the 4 km CARMMS domain.
- Seasonal and monthly evaluation should be included.
- Evaluation for high observed concentrations should be made.
- Several graphical displays of model performance may be used, including, but not limited to:
 - Scatter Plots of predicted and observed concentrations/depositions.
 - Spatial Maps of performance, including spatial maps of model predictions with superimposed observations and interpolated spatial maps of bias and error.
 - Time Series Plots of predicted and observed concentrations using native observation averaging time.
 - Soccer Plots that compare model performance statistics with model performance goals (Table B-3).

Details on the CAMx 2008 model performance evaluation are provided in the WestJumpAQMS final report and supporting material. Below we summarized the CAMx model performance evaluation statistical metrics for just within the CARMMS 4 km modeling domain that is the subject of this study.

B.5 Model Evaluation within the 4 km CARMMS Domain

WestJumpAQMS developed a separate CAMx 4 km modeling database for the 2008 annual period and the 4 km CARMMS modeling domain (see Figure 2-1) that covers all of Colorado, the northern two-thirds of New Mexico as well as eastern Utah and northeastern Arizona.

WestJumpAQMS conducted a separate model performance evaluation of the CAMx 2008 base case simulation for the CARMMS 4 km domain that is summarized from the WestJumpAQMS final report (ENVIRON, Alpine and UNC, 2013) in this section. Also presented below are some supplemental ozone evaluation results as suggested by the IAQRT in their February 28, 2014 meeting.

Figures B-1 through B-4 displays the monthly and annual daily maximum 8-hour (DMAX8) and hourly ozone model performance statistics across all CASTNet (top) and AQS (bottom) sites in the 4 km CARMMS domain using observed ozone cut-off concentrations of 40 and 60 ppb. The Fractional Bias and Error (FB and FE) and Normalized Mean Bias and Error (NMB and NME) performance statistics are used in these Figures. The Mean Normalized Bias and Error (MNB and MNE) statistics are not presented following the recommendations of Simon, Baker and Philips (2012). The CARMMS ozone model performance statistics are compared against EPA's 1991 bias ($\leq \pm 15\%$) and error ($\leq 35\%$) ozone model performance goals (Table B-2). The CAMx 4 km model pDMAX8 ozone performance evaluation across CASTNet and AQS monitors within the CARMMS 4 km domain using the FB 40 ppb cut-off are $\leq \pm 6\%$ with an annual FB of less than 2%, which achieves the ozone bias $\leq \pm 15\%$ performance goal by a wide margin (Figure B-1a). Similarly, the monthly DMAX8 ozone FE tends to be between 5% and 12%, so achieves the ozone performance goal of $\leq 35\%$ by over a factor of 2 (Figure B-1a). Some of the underestimation of the DMAX8 ozone at the Colorado CASTNet sites (e.g., in May) may be due in part to the model's inability to fully simulate stratospheric ozone intrusion events (e.g., at Gothic). Figure B-1b presents similar DMAX8 ozone modeling results for the NMB and NME performance statistics using a 40 ppb cut-off that also exhibit very good model performance statistics that achieves the ozone model performance goals.

Figure B-2 presents similar DMAX8 ozone performance statistics as Figure B-1 only using a 60 ppb ozone cut-off value instead of 40 ppb. With a focus on higher observed ozone concentrations then it is not surprising that the model exhibits an underestimation bias. The maximum underestimation bias occurs in the late winter and spring when stratospheric ozone and winter ozone events occur that the model has difficulty in reproducing. The DMAX8 ozone with 60 ppb cut-off performance statistics still achieve the ozone error performance goal for all months and bias goal for all months except February 2008.

Figure B-3 and B-4 are like Figure B-1 and B-2 only for hourly ozone model performance instead of DMAX8 ozone. The hourly ozone model performance using a 40 ppb cut-off value achieves the ozone goals for all months of the year (Figure B-3); it is encouraging that much better ozone performance is seen during the summer ozone season. Using a 60 ppb ozone cut-off, the hourly ozone underestimation bias is so great during the winter months that it exceeds the ozone model performance goal (Figure B-4). However, during the summer when the observed and model ozone is higher and is the primary ozone period of concern, CAMx achieves the ozone model performance goals.

The CAMx 4 km total PM_{2.5} mass performance across the FRM, IMPROVE and CSN sites in the 4 km CARMMS domain is shown in Figure B-5. The model tends to overestimate PM_{2.5} in the winter falling to a near zero bias in the summer. However, the overestimation bias is usually within the PM Performance Criteria with only 5 of the 36 monthly FBs (14% of the time) failing to achieve the PM Performance Criteria. 14 months achieve the PM Performance goal (~40% of the time), which occur in the summer and months adjacent to the summer.

Figures B-6 and B-7 display the CAMx 4 km model performance related to sulfur species that includes SO₄ at IMPROVE, CSN and CASTNet monitoring networks, SO₂ at CASTNet and wet SO₄ deposition at NADP. SO₄ tends to be overestimated in the winter and underestimated in the spring, summer and early fall. SO₂ is also overestimated in the winter and fall with near zero bias to underestimating in the spring and summer, which indicates that the summer SO₄ underestimation is not due to insufficient oxidation of available SO₂ concentrations. The wet SO₄ deposition also is overestimated in the winter and underestimated in the summer suggesting that too rapid wet depositions is not the cause of the summer SO₄ underestimation tendency. The summer underestimation of wet SO₄ deposition also suggests that the overstated WRF convective precipitation is not overly washing out the atmospheric pollutants.

Figures B-8 and B-9 displays CAMx 4 km model performance statistics related to nitrogen species including NO₃, HNO₃ and combined NO₃ plus HNO₃. Monthly NO₃ performance at the IMPROVE sites almost always achieves the PM Performance Goal, whereas it is generally underestimated across the CSN and CASTNet networks with the largest underestimation bias occurring in the summer. On the other hand, HNO₃ tends to be overestimated by the CAMx 4 km CARMMS base case and the performance of total nitrate (HNO₃+NO₃) exhibits much better performance with near zero bias in the spring and summer that achieves the PM Performance Goals. These results suggest that some of the NO₃ underestimation bias may be due to not enough conversion of the gaseous HNO₃ to particulate NO₃. This could be due to insufficient ammonia present to buffer the nitric acid or not fully accounting for other basic compounds that can neutralize nitric acid (e.g., Calcium, Sodium, etc.). Thermodynamic variables could also partly account for this if the temperatures were too hot or the atmosphere not moist enough.

NH₄ model performance across the IMPROVE, CSN and NADP networks in the CARMMS 4 km domain is shown in Figure B-10. NH₄ is underestimated, which is consistent with the SO₄ and NO₃ underestimation bias, with the performance being better across the CSN network that always achieves the PM Performance Criteria and sometimes achieves the PM Performance Goal. The underestimation bias is greater across the IMPROVE network due to the use of derived NH₄d in the evaluation that overestimates actual ambient NH₄ concentrations. The NH₄ wet deposition exhibits near zero or an underestimation bias indicating that the NH₄ underestimation tendency is not due to overstated wet scavenging.

The CAMx 4 km model performance for gaseous NO_x and NO_y across AQS and nonmethane organic compounds (NMOC) across PAMS monitoring sites are shown in Figure B-11. NO_x is underestimated in the winter with near zero bias in the summer, whereas NO_y is overestimated in the summer, underestimated in the winter and has near zero bias in the spring. Given that these measurements may have artifacts and picking up other reactive nitrogen species, it is hard to interpret the evaluation. NMOC is underestimated throughout the year, which may be due in part to the fact they tend to be sited in urban areas.

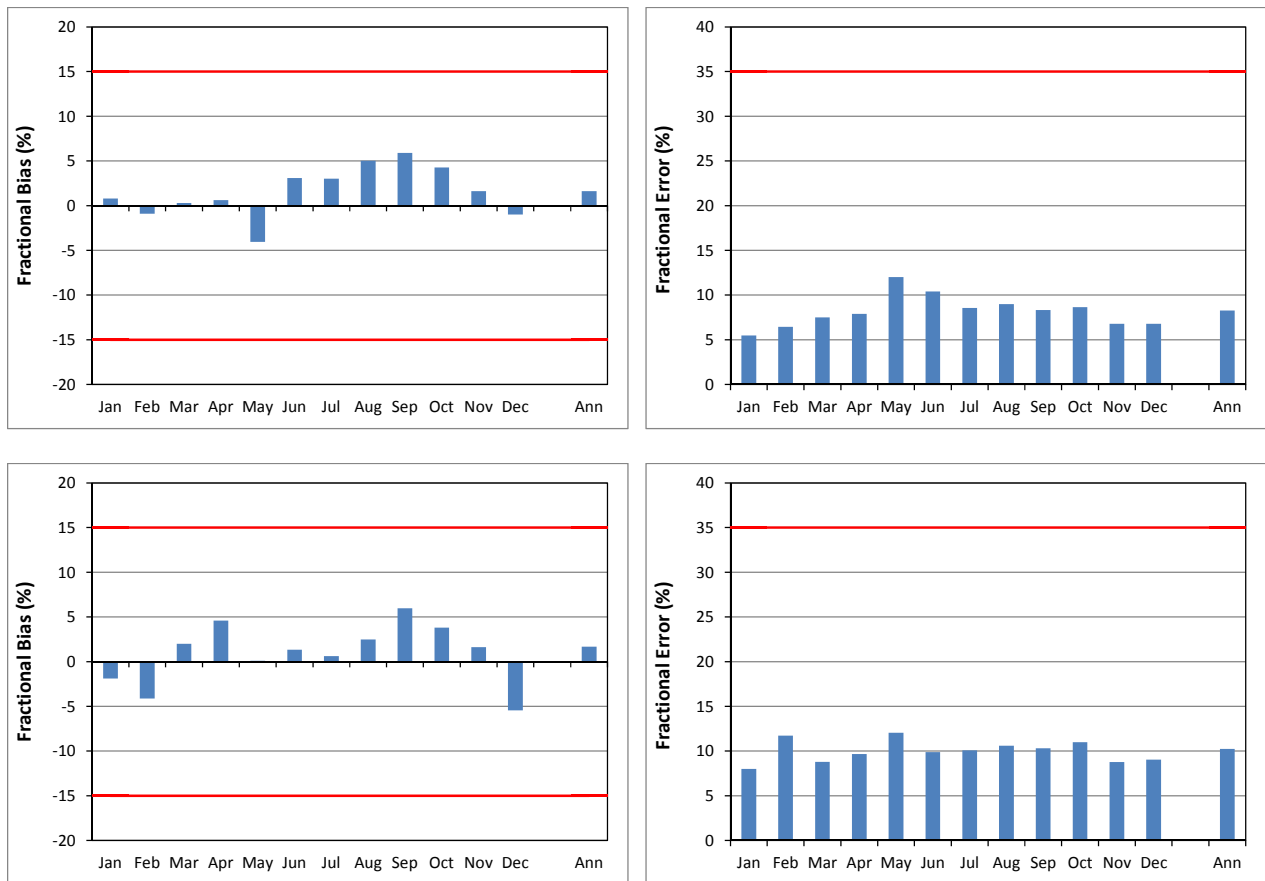


Figure B-1a. CAMx 4 km daily maximum 8-hour ozone model performance for Fractional Bias (left) and Fractional Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 40 ppb observed ozone cut-off value.

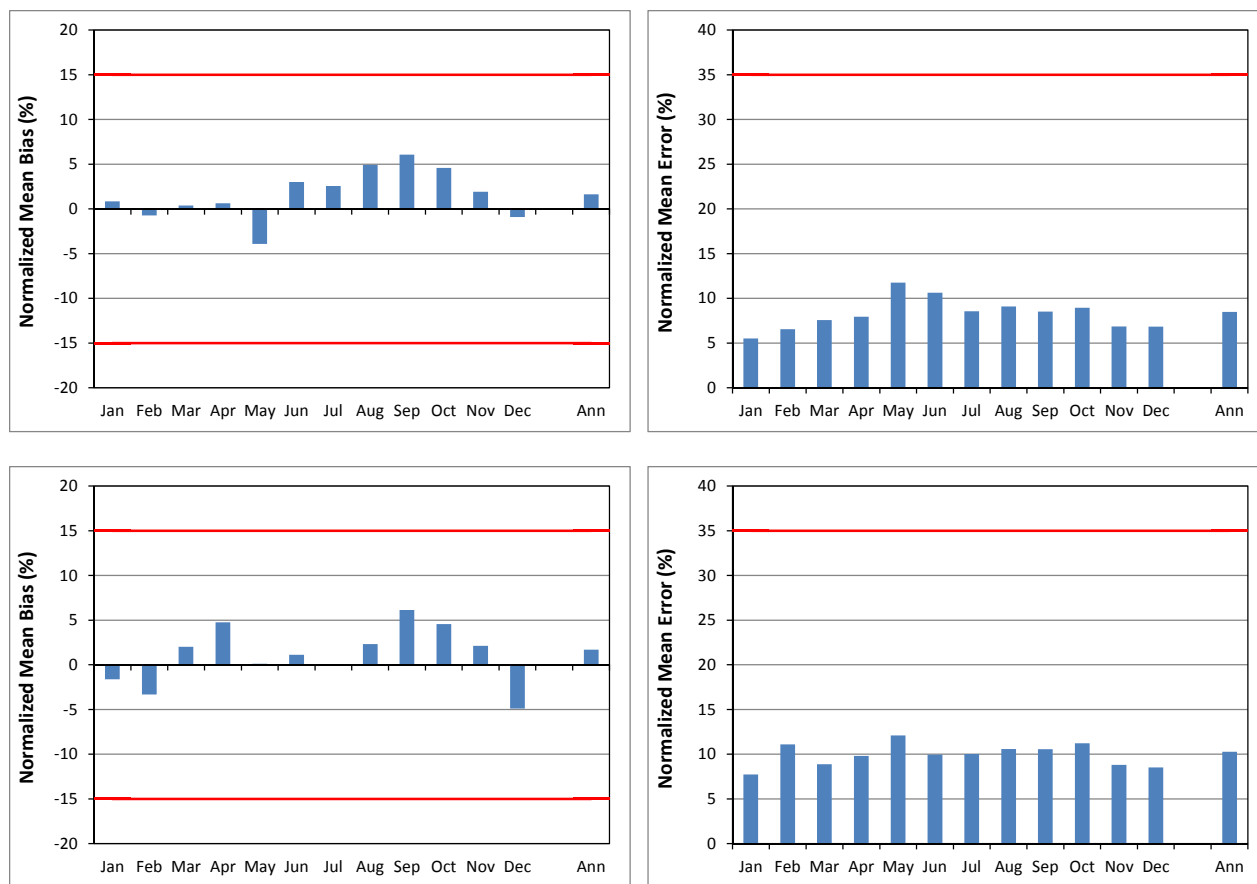


Figure B-1b. CAMx 4 km daily maximum 8-hour ozone model performance for Normalized Mean Bias (left) and Normalized Mean Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 40 ppb observed ozone cut-off value.

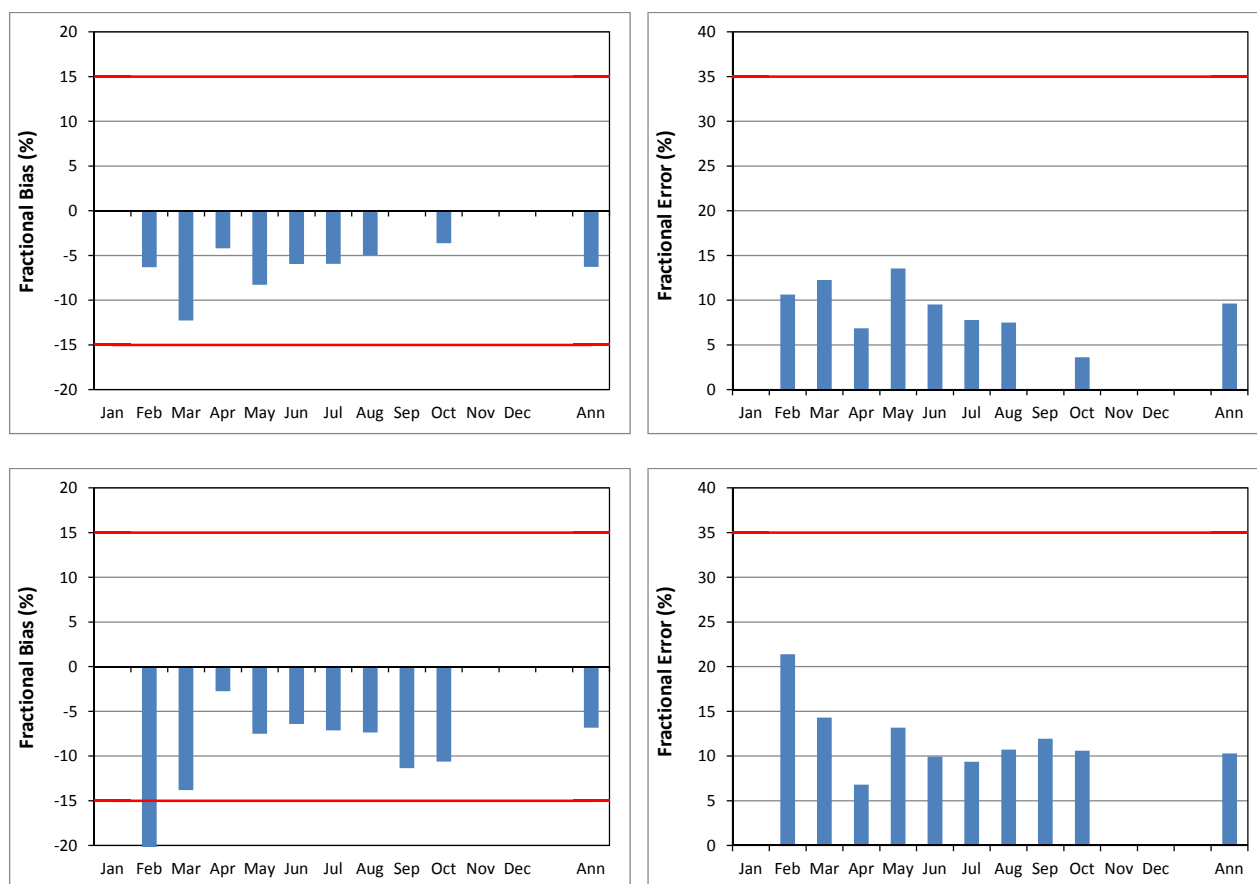


Figure B-2a. CAMx 4 km daily maximum 8-hour ozone model performance for Fractional Bias (left) and Fractional Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 60 ppb observed ozone cut-off value.

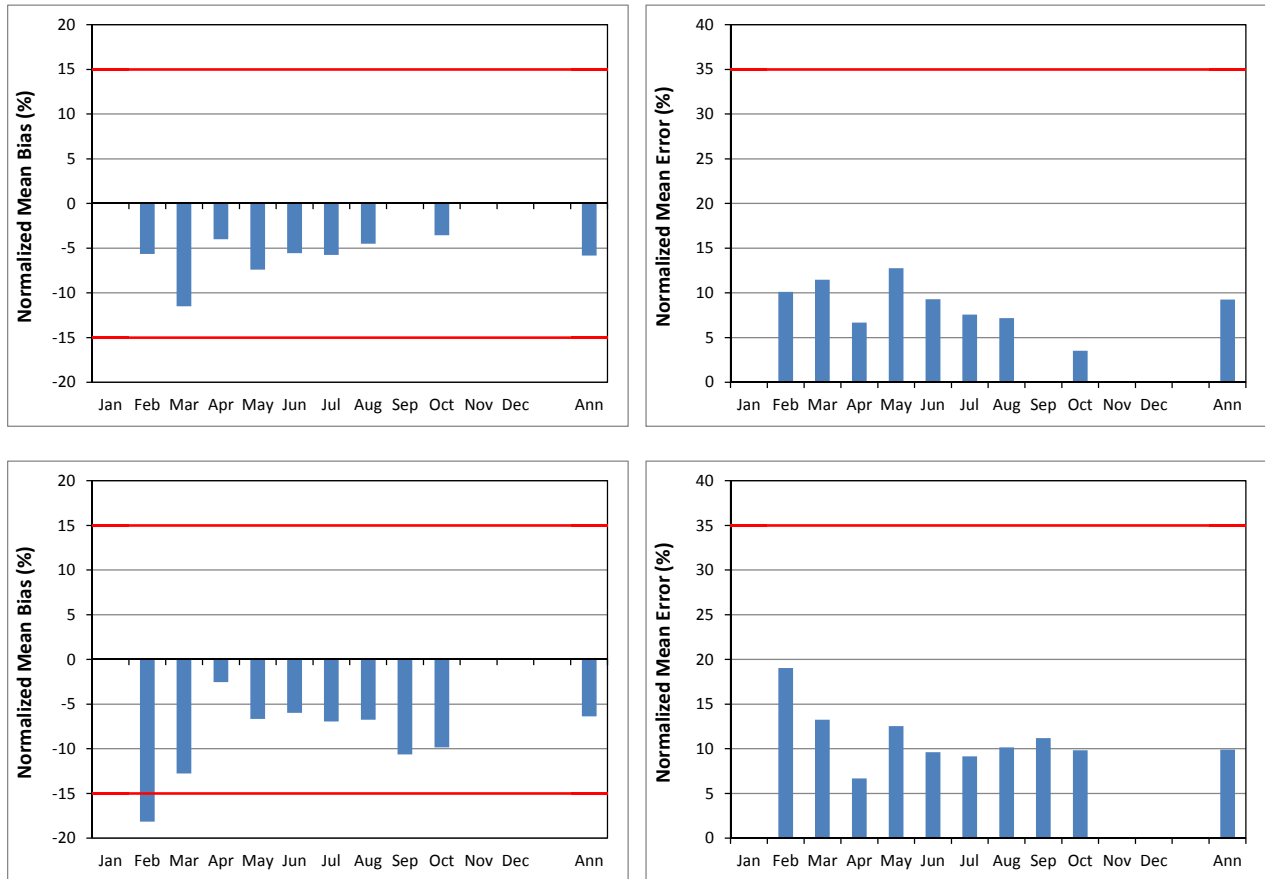


Figure B-2b. CAMx 4 km daily maximum 8-hour ozone model performance for Normalized Mean Bias (left) and Normalized Mean Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 60 ppb observed ozone cut-off value.

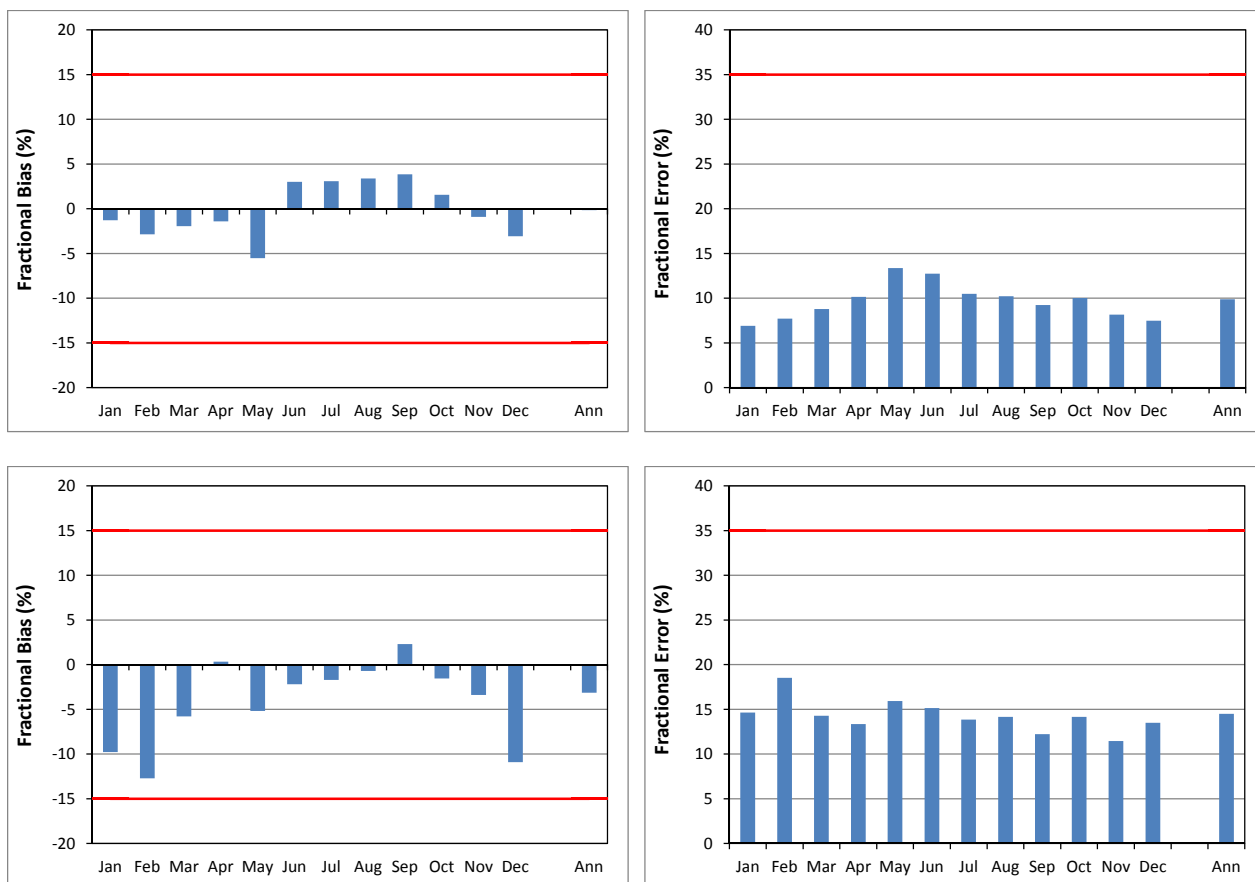


Figure B-3a. CAMx 4 km hourly ozone model performance for Fractional Bias (left) and Fractional Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 40 ppb observed ozone cut-off value.

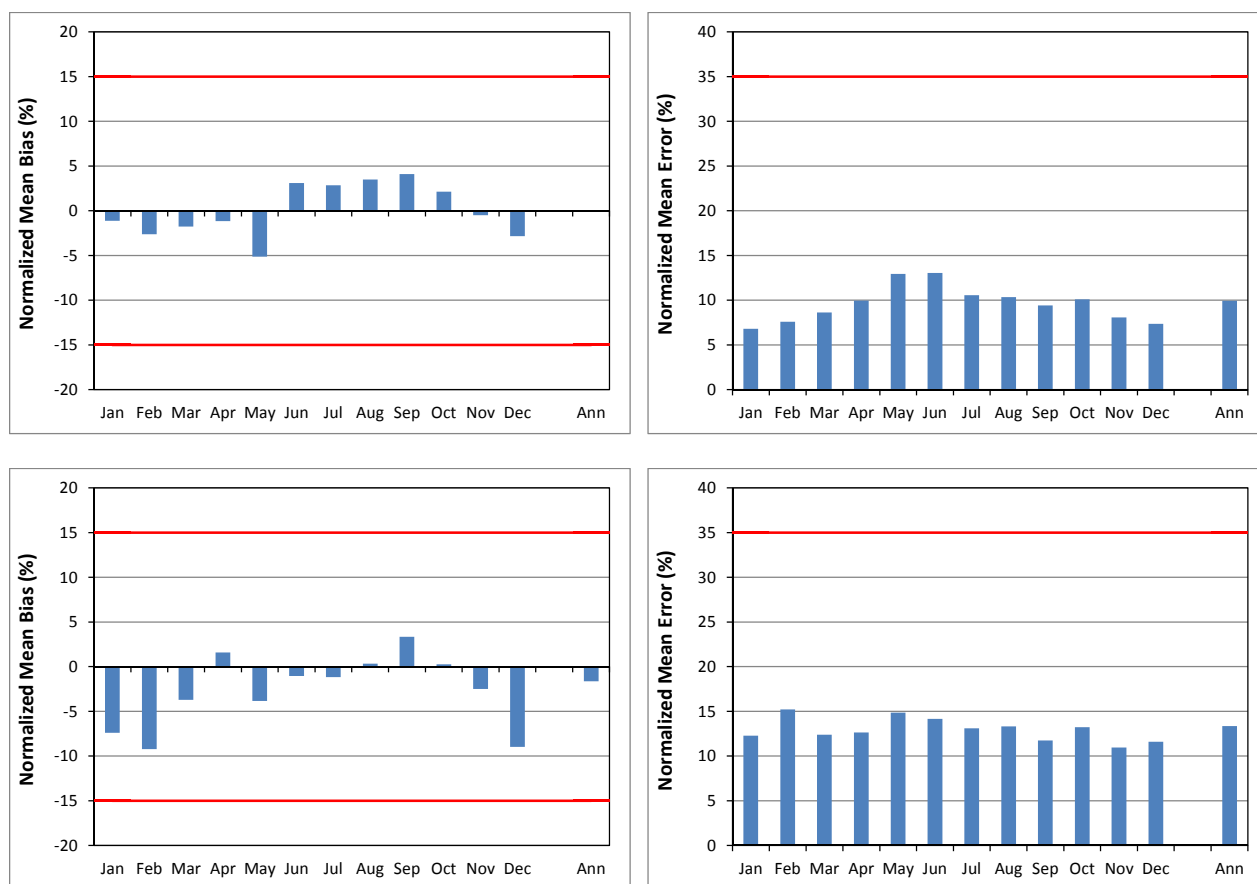


Figure B-3b. CAMx 4 km hourly ozone model performance for Normalized Mean Bias (left) and Normalized Mean Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 40 ppb observed ozone cut-off value.

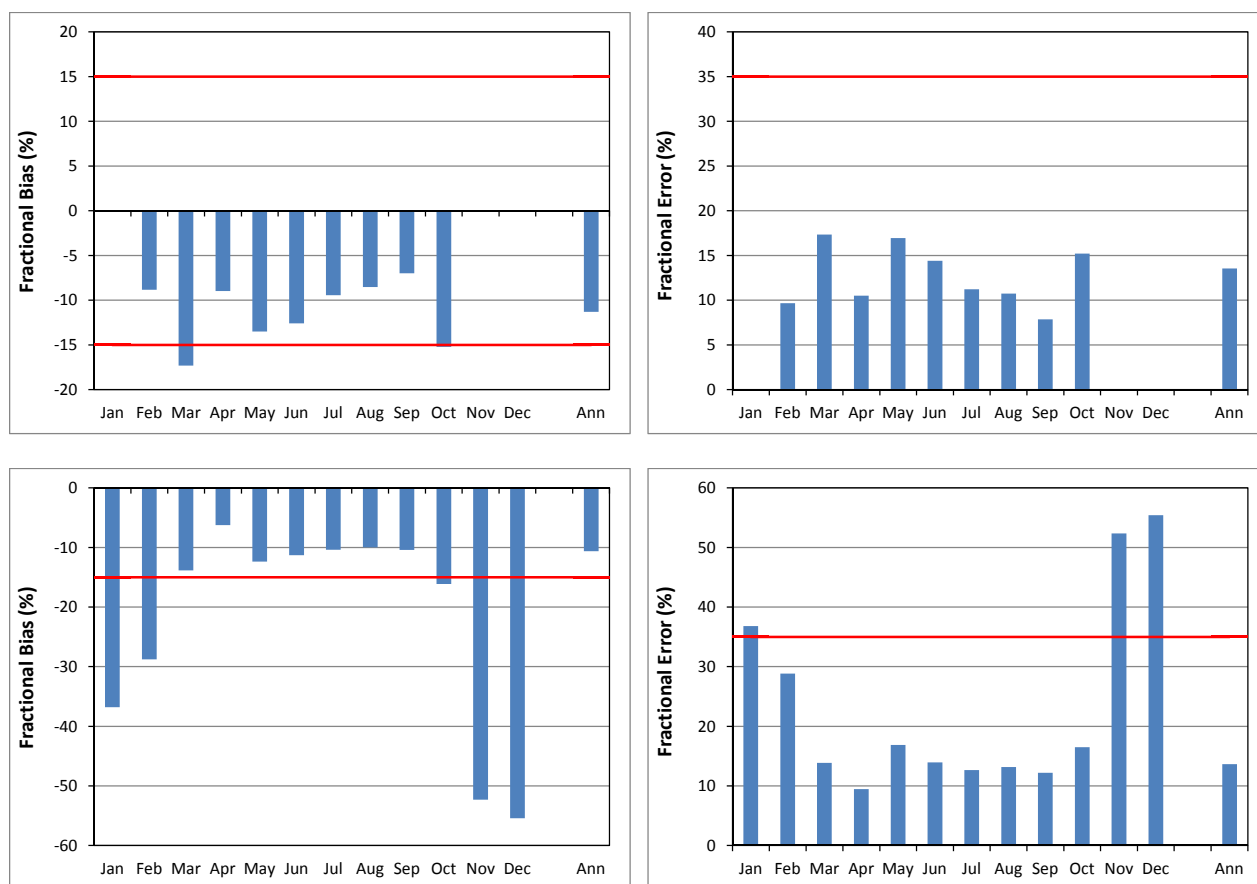


Figure B-4a. CAMx 4 km hourly ozone model performance for Fractional Bias (left) and Fractional Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 60 ppb observed ozone cut-off value.

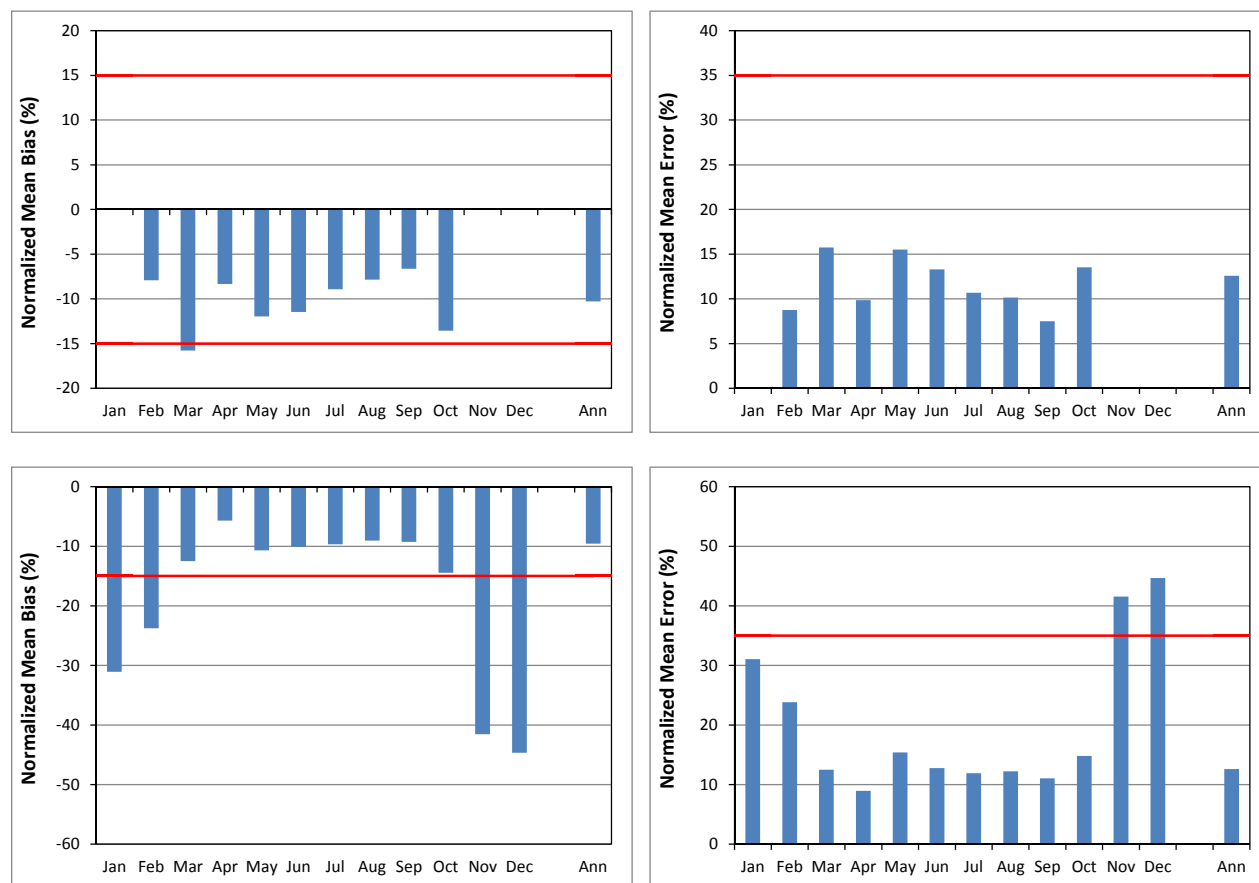


Figure B-4b. CAMx 4 km hourly ozone model performance for Normalized Mean Bias (left) and Normalized Mean Error (right) across CASTNet (top) and AQS (bottom) monitors within the CARMMS 4 km domain using a 60 ppb observed ozone cut-off value.

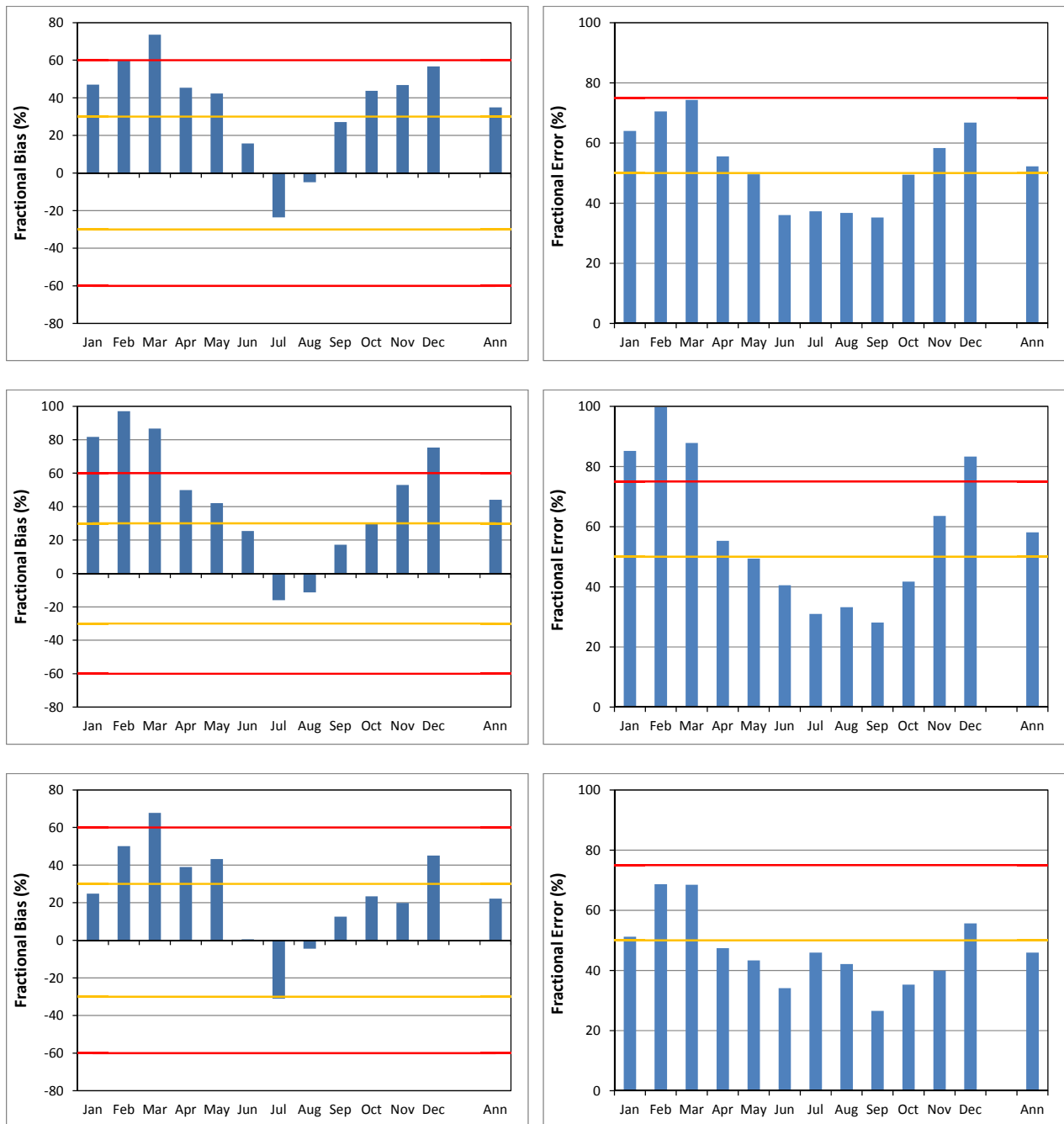


Figure B-5. CAMx 4 km PM_{2.5} model performance for FB (left) and FE (right) across FRM (top), IMPROVE (middle) and CSN (bottom) monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

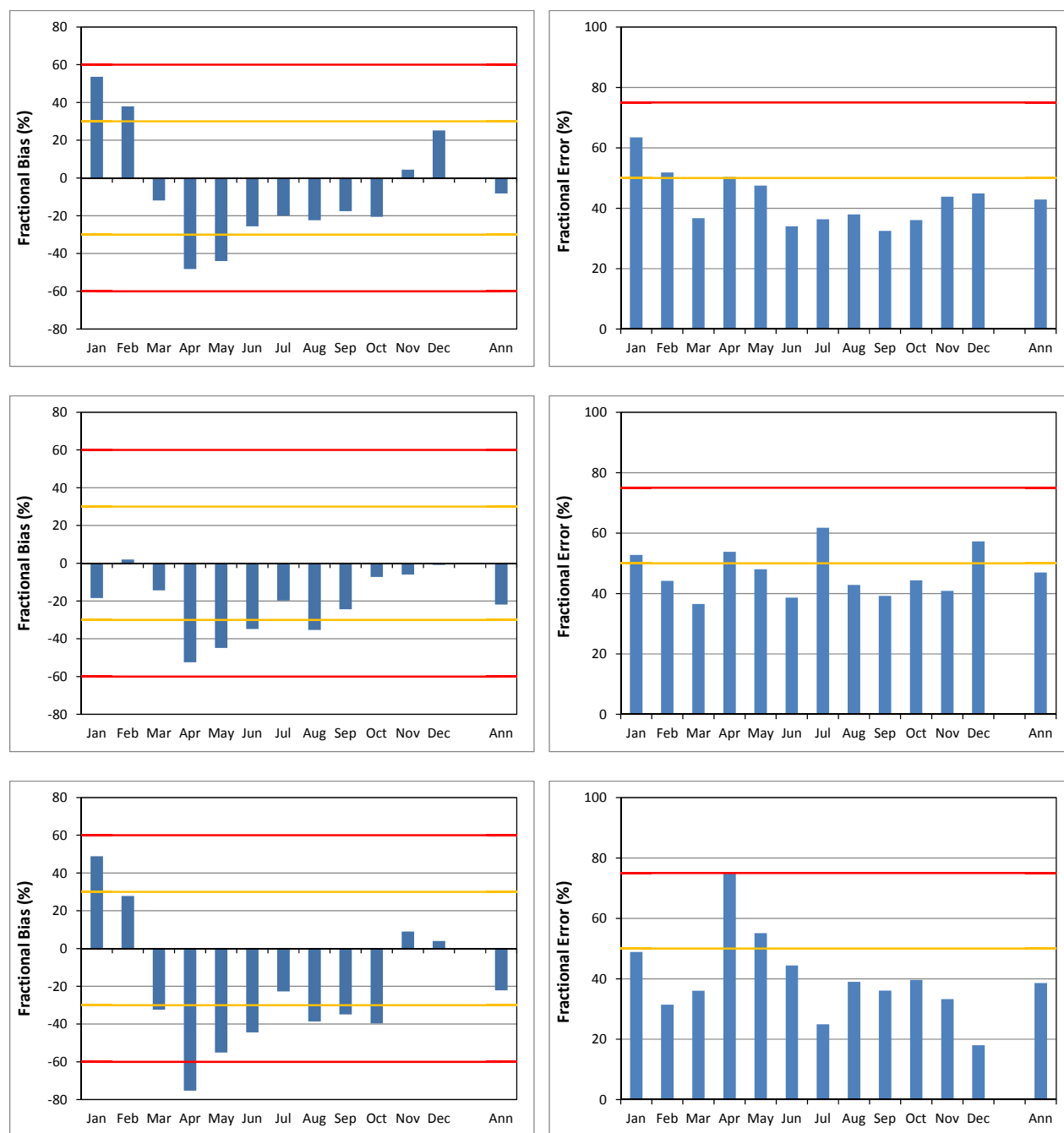


Figure B-6. CAMx 4 km Sulfate (SO₄) model performance for FB (left) and FE (right) across IMPROVE (top), CSN (middle) and CASTNet (bottom) monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

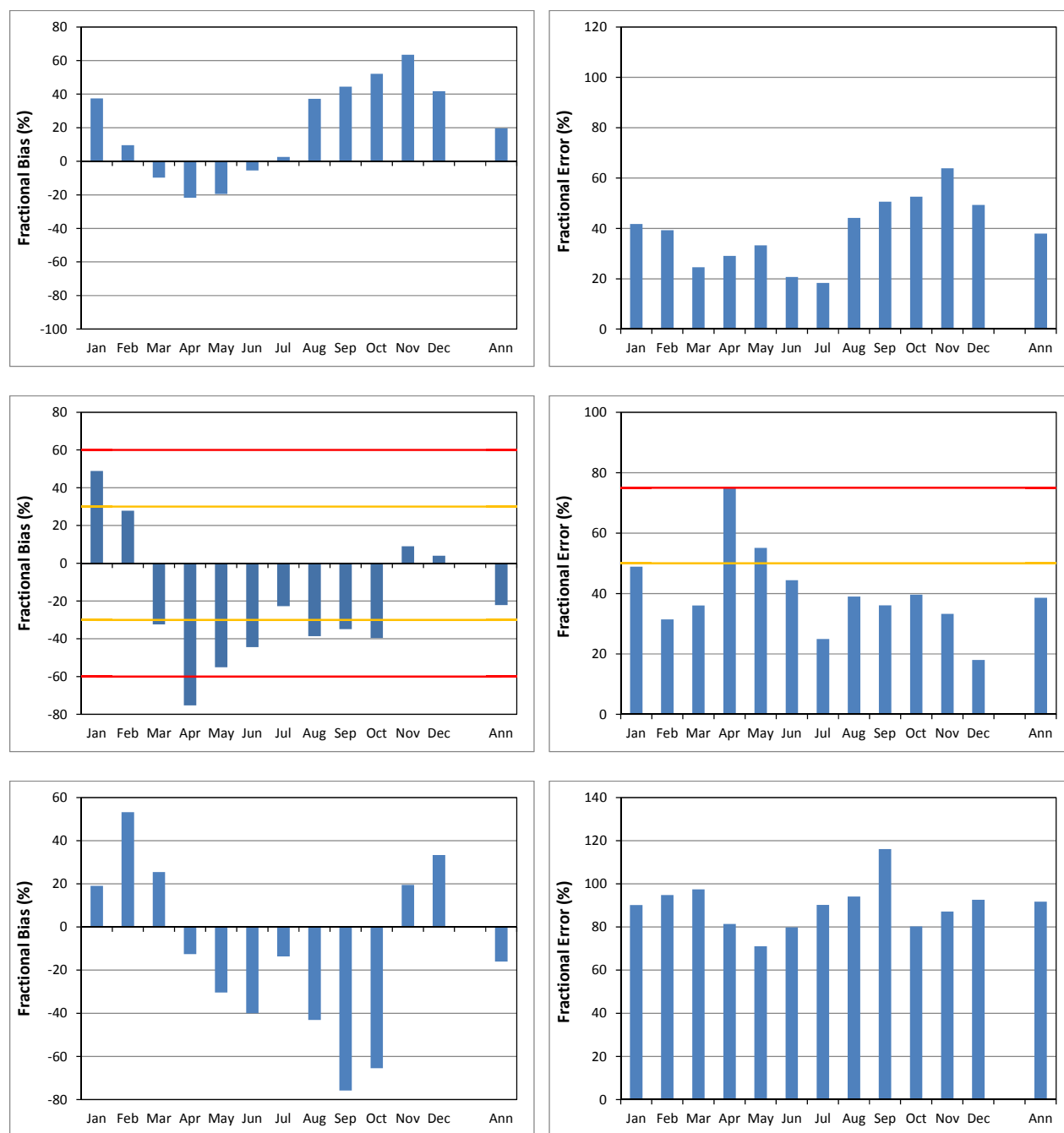


Figure B-7. CAMx 4 km SO₂ (top) and SO₄ (middle) at CASTNet and SO₄ Wet Deposition (bottom) at NADP model performance for FB (left) and FE (right) monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

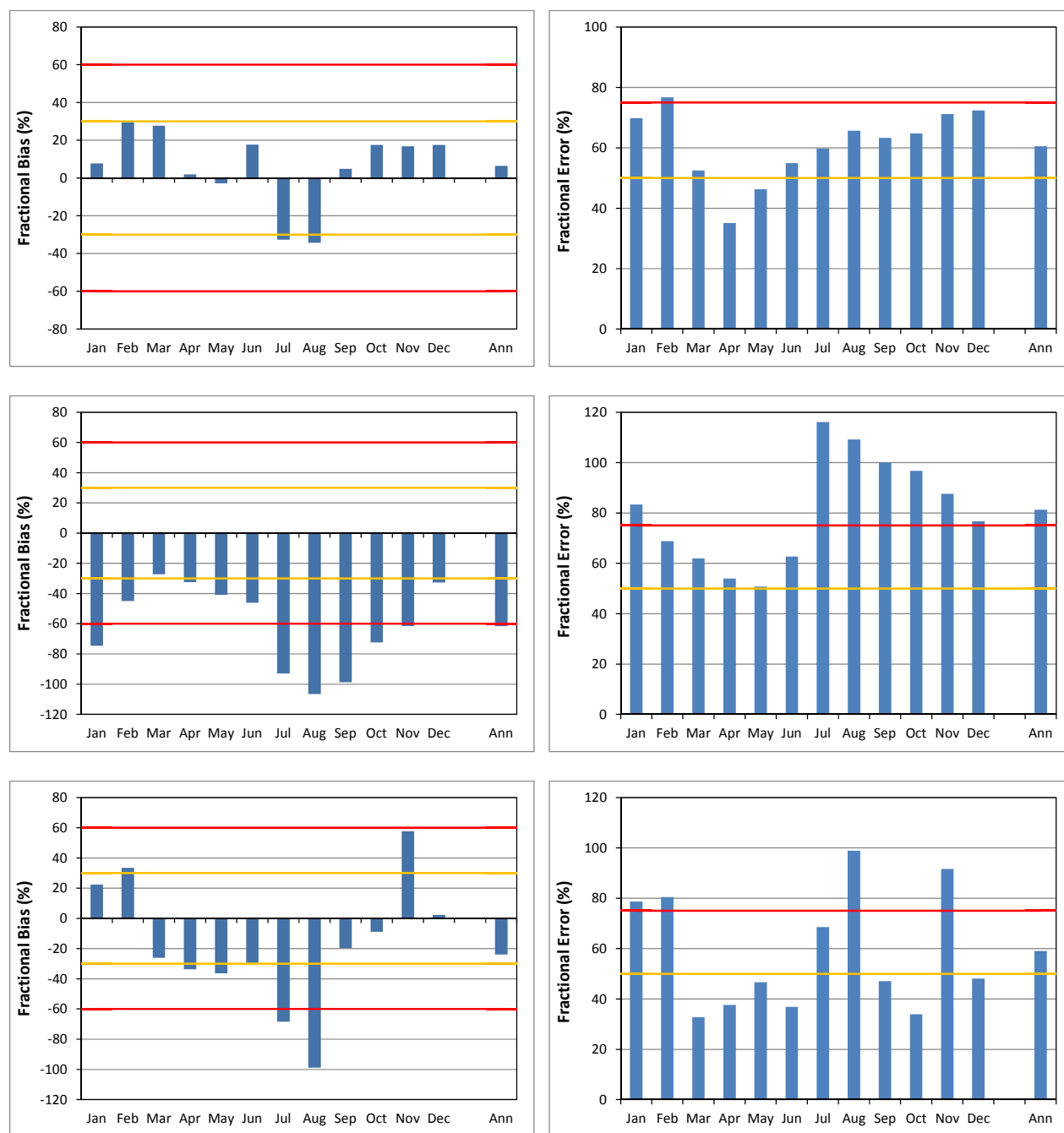


Figure B-8. CAMx 4 km NO₃ model performance for FB (left) and FE (right) across IMPROVE (top), CSN (middle) and CASTNet (bottom) monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

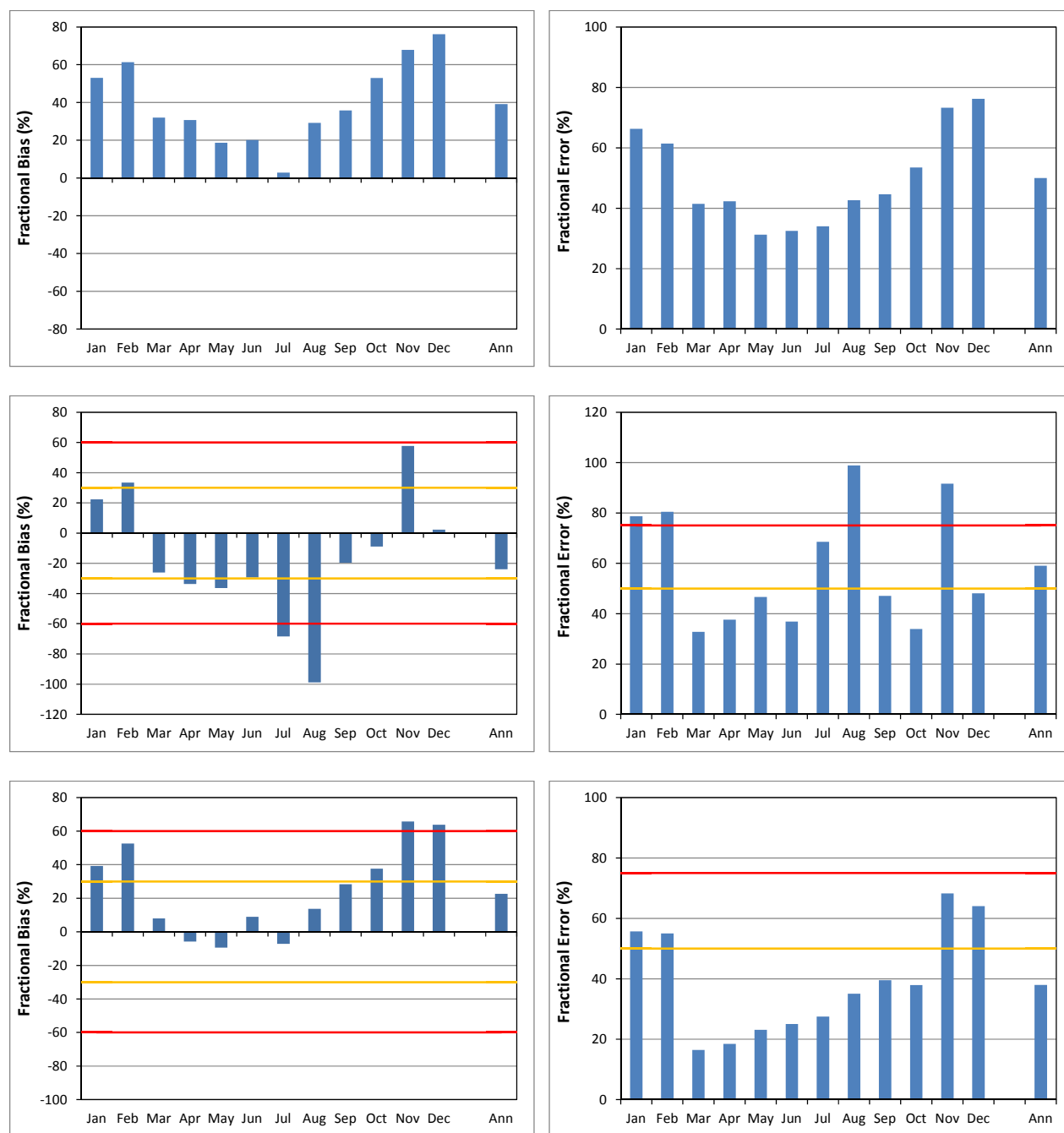


Figure B-9. CAMx 4 km HNO₃ (top), NO₃ (middle) and tHNO₃+NO₃ (bottom) model performance for FB (left) and FE (right) across CASTNet monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

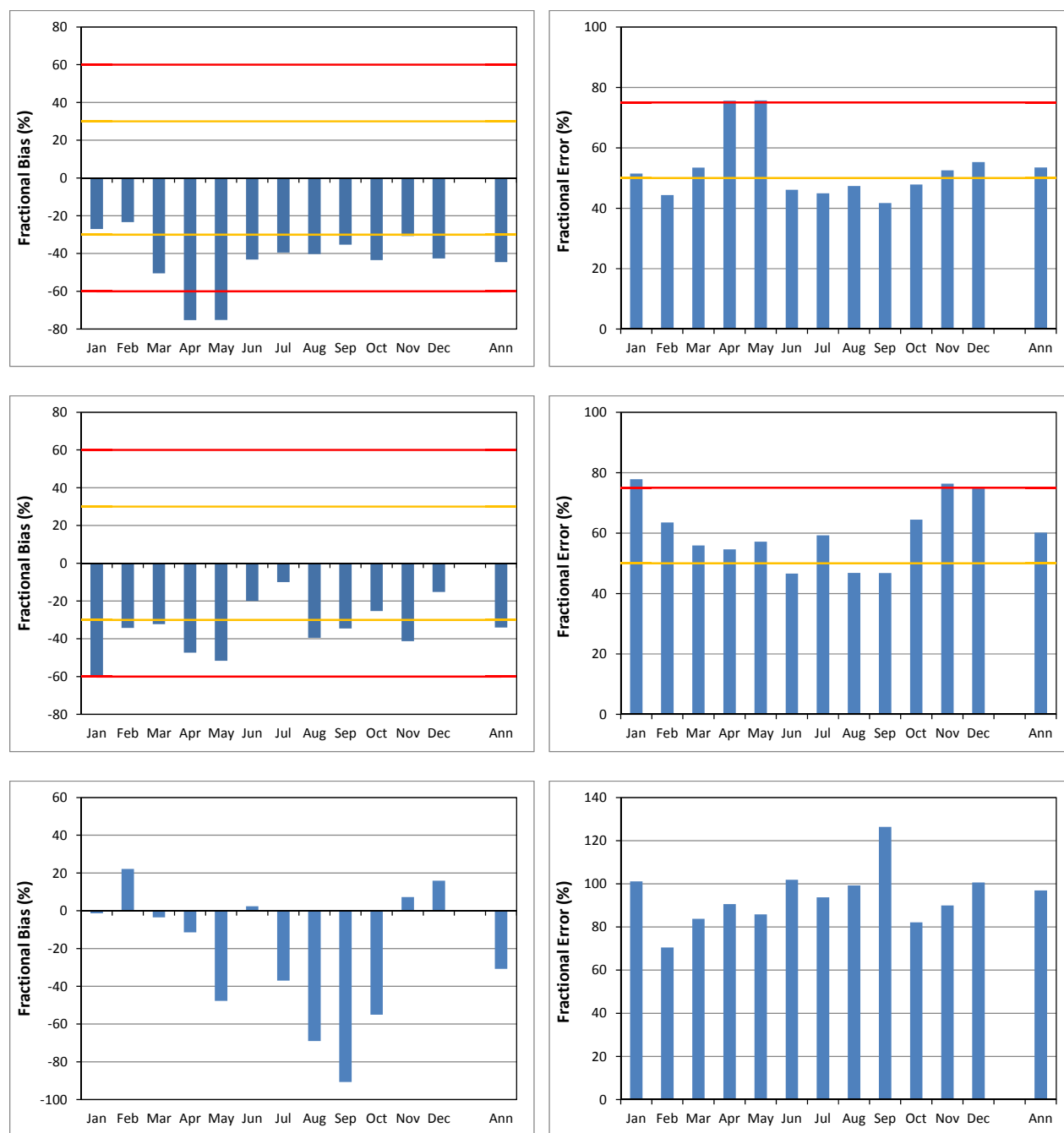


Figure B-10. CAMx 4 km NH₄ concentration and wet deposition model performance for FB (left) and FE (right) across IMPROVE (top), CSN (middle) and NADP (bottom) monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

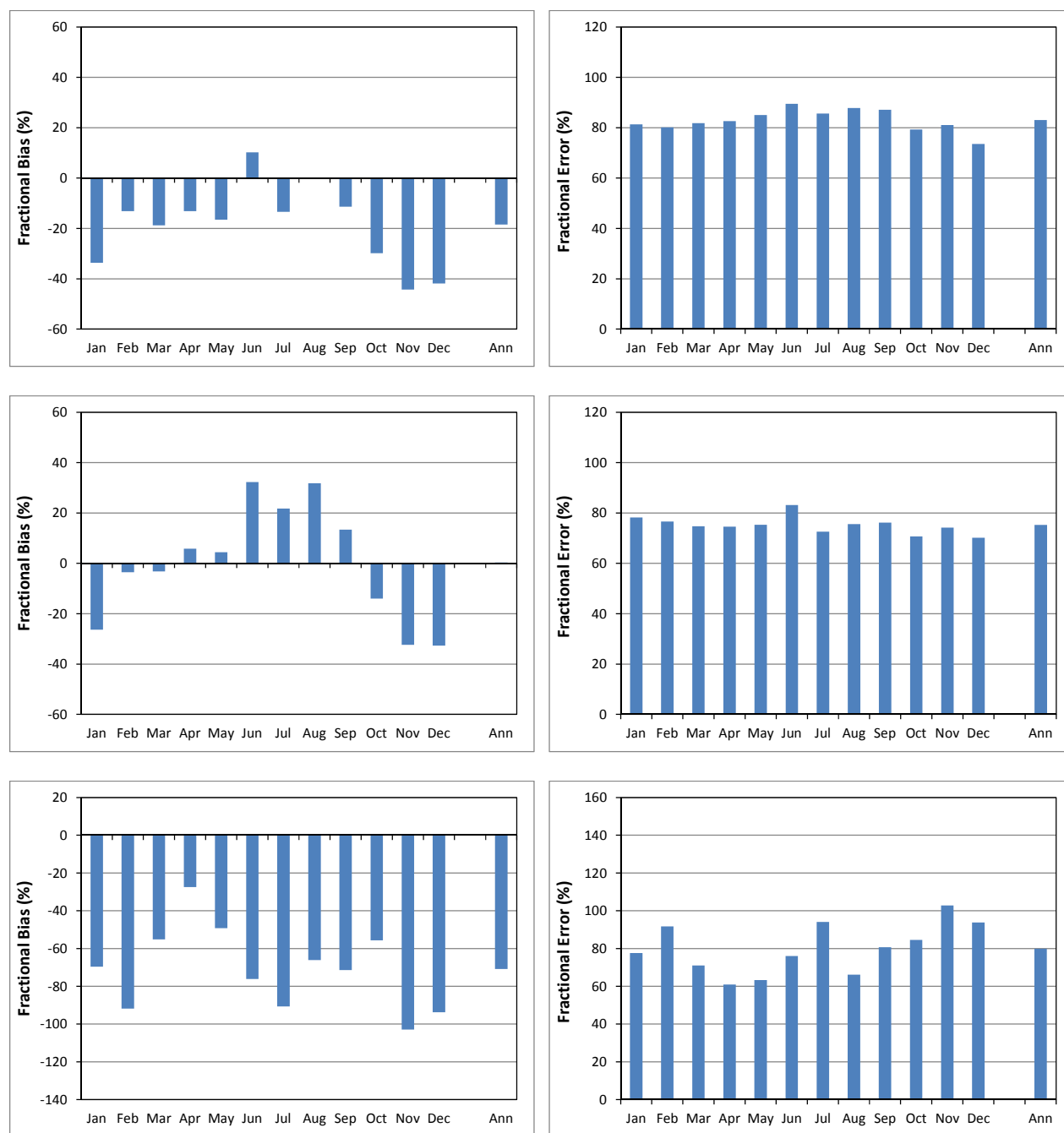


Figure B-11. CAMx 4 km NO_x (top), NO_y (middle) and NMOC (bottom) model performance for FB (left) and FE (right) across AQS and PAMS) monitors within the CARMMS 4 km Impact Assessment Domain (IAD).

APPENDIX C

CARMMS Technical Memorandum Draft Final CARMMS Oil and Gas Emission Calculator Documentation August 15, 2013

August 15, 2013

MEMORANDUM

To: Chad Meister and Forrest Cook, BLM Colorado State Office
From: John Grant, Jim Zapert, and Ralph Morris
Subject: Draft Final CARMMS Oil and Gas Emission Calculator Documentation

1.0 INTRODUCTION

1.1 Scope and Goals

The purpose of this document is to explain the emissions calculation procedures used in the oil and gas emission calculators that have been developed for the Western Colorado Air Resource Management Modeling Study (West-CARMMS). We have improved existing emissions calculators and develop representative calculators for “typical” crude oil, conventional gas (with condensate), coal bed natural gas (CBNG), and shale gas within the region. New information has been incorporated for drilling times; engine configurations; condensate and produced water production; well pad versus offsite gas treatment and storage; well-head, infield, and pipeline compression; and gas/oil production. The ability to readily modify input assumptions such as production parameters, emission control assumptions, and wellhead equipment configurations has also been incorporated into the calculator.

The refined emission calculators will be used to develop the baseline and future-year emissions inventories under Task 2 for the Western Colorado Bureau of Land Management (BLM) planning areas (see Figure 1-1).

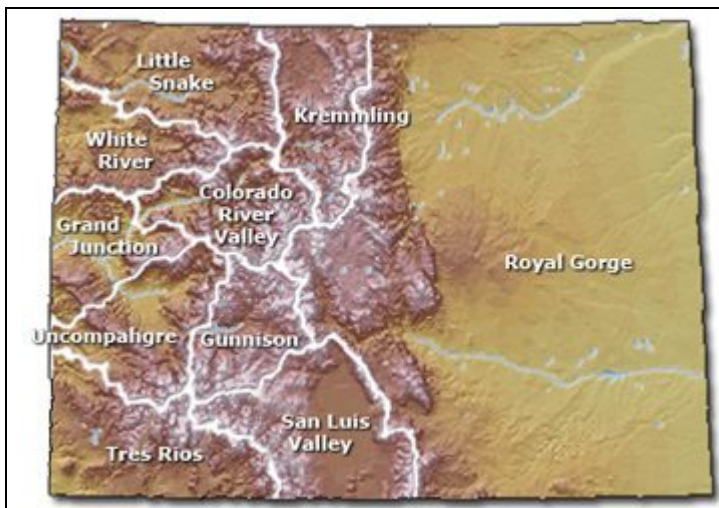


Figure 1-1. Colorado Field Office Planning Areas.

1.2 Overview of Calculators

Emission calculators have been developed for each of the following well types.

- Conventional gas
- Conventional oil
- Shale gas
- Coalbed natural gas (CBNG)

For each well type a separate, a self-contained emission calculator spreadsheet contains all of the inputs and calculations need to generate wellsite emissions.

Additionally, a calculator has been developed to estimate midstream emissions for each area. The midstream emission calculator draws upon Colorado Department of Public Health (CDPHE) Air Pollutant Emission Notice (APEN) emissions for base year emission estimates. Future year midstream emission projections are dependent on the change in oil and gas production in a given planning area which can be updated based on linkages to the by well type emission calculators.

1.2.1 Pollutants

The emission calculators include estimates of emissions of criteria air pollutants (CAPs), greenhouse gases (GHGs), and hazardous air pollutants (HAPs) as follows:

- Criteria Pollutants
 - Carbon monoxide (CO)
 - Nitrogen oxides (NO_x)
 - Particulate matter less than or equal to 10 microns in diameter (PM₁₀)
 - Particulate matter less than or equal to 2.5 microns in diameter (PM_{2.5})
 - Sulfur dioxide (SO₂)
 - Volatile Organic Compounds (VOCs)
- Greenhouse Gases
 - Carbon dioxide (CO₂)
 - Methane (CH₄)
 - Nitrous oxide (N₂O)
- Hazardous Air Pollutants (HAPs)

While lead (pb) is a criteria pollutant, emissions of lead in the BLM western Colorado planning areas are expected to be extremely low and are therefore not included in this analysis.

HAP emissions were estimated for each emissions source. For oil and gas emissions sources, HAP emissions from venting and combustion source categories were estimated for formaldehyde, n-hexane, benzene, toluene, ethylbenzene, and xylenes (BTEX).

Anthropogenic greenhouse gas emission inventories typically include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and fluorinated gases. Fluorinated gases are not expected

to be emitted in appreciable quantities by any category considered in this emission inventory and were therefore not included in this analysis.

1.2.2 Temporal

The calculators estimate annual emissions associated with oil and gas exploration. Per the West-CARMMS scope of work, base year emissions are estimated for 2011 with annual emission forecasts to 2021.

2.0 CALCULATOR DEVELOPMENT

2.1 Calculator Inputs

The emission calculator for each well type allows for specification of the following inputs.

- Base year oil and gas activity (gas production, oil production, spud counts, active well counts)
- Well decline estimates
- Level of control by source category
- Gas composition
- Equipment configurations (e.g. drill rigs, fracing rigs)
- Gas venting activity (e.g. completions, blowdowns)

The inputs are implemented to estimate by source category emissions as described below. Appendices A, B, C, and D show the by source category inputs for each well type.

The midstream emission calculator includes estimates of base year 2011 gas plant and compressor station emissions taken from CDPHE APEN data. Base year midstream emissions are projected to future years based upon the gas production in each planning area. Appendix C5 shows base year 2011 midstream emissions by field office and facility as reported in APENS data.

2.2 Emission Calculations

Emission calculations for all emission-generating activities were developed based on typical emission inventory methodology. Methods used to estimate emissions from each source category are explained in Section 2.2.1. For each source category, emissions for the base year were estimated. Emissions were then forecasted to future years, accounting for activity growth and for applicable sources emissions controls.

The methodologies described here are used consistently in all four calculators by well type; however the input data of each calculator was selected to best reflect the operational characteristics of each well type (oil, gas, CBNG, and shale gas) and thus obtained from literature sources including the following Air Quality Technical Support Documents (AQTSD) from Colorado field office planning areas and BLM emission calculators listed below; shale gas calculator inputs were taken from a recent shale gas project (Bull Mountain, Zapert, 2013) in the Uncompahgre field office:

- White River AQTSD (URS, 2012a)
- Colorado River Valley AQTSD (URS, 2012b)
- Grand Junction AQTSD (ENVIRON, 2012a)
- Uncompahgre AQTSD (ENVIRON, 2012b)
- BLM Crude Oil Well Gas Emission Calculator (BLM, 2013a)
- BLM Coalbed Natural Gas Well Emission Calculator (BLM, 2013b)

Emissions are generated in three main phases of oil and gas systems:

- Emissions from Well Construction and Development
- Emissions from the Production Phase (occurring at-or-nearby the well pad)
- Emissions from Midstream Sources (Central Gas Compression and Processing)

The methodologies implemented to estimate base year and future year emissions from oil and gas sources are explained in this section.

2.2.1 Emissions from Well pad Construction and Development

Emissions from Well pad Construction and Development include those generated by equipment, vehicles and activities related to well pad construction, access roads construction, pipeline construction, wellbore drilling and well completions. Table 2-1 includes the emission sources identified for the well pad construction and development phase. Pollutant emissions are initially estimated on a per surrogate basis and later scaled with the projected surrogate estimate to obtain area-wide annual emissions from each source.

Table 2-1. Construction source categories and scaling surrogates.

Equipment Source Category	Emissions units per event	Scaling Surrogate
Well Pad, Access Road, and Pipeline Construction Equipment	tons/new pad	New pads per year
Well Pad, Access Road and Pipeline Construction Traffic	tons/new pad	New pads per year
Drilling Equipment and Completion Equipment	tons/spud	Spuds per year
Fracing Equipment	tons/spud	Spuds per year
Refracing Equipment	tons/well	Active wells per year
Drilling and Well Completion Traffic	tons/spud	Spuds per year
Rig Hauling and Rig Moving Traffic	tons/pad	New pads per year
Well Pad, Access Road and Pipeline Construction Wind Erosion	tons/new pad	New pads per year
Well Completion Venting	tons/spud	Spuds per year

2.2.1.1 Well Pad, Access Road, and Pipeline Construction Equipment

This category refers to emissions associated with off-road engines used during construction of well pads, access roads and pipelines and is also inclusive of well pad reclamation activity. Detailed data for each engine type such as horsepower rating, hours of operation, fuel type,

engine technology and load factors were derived from the literature. The EPA NONROAD2008a model (USEPA, 2009b) was used to compile emission factors for each equipment type. The N₂O emissions factor was obtained from the 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17 (API, 2009). Engines were classified in three types as activity data and emissions factors vary by utility: well pad construction equipment, access road construction equipment and pipeline construction equipment.

Emissions on a per event (new well pads) basis for an engine type for which data was provided were estimated according to Equation 1:

$$E_{engine\ k,i} = \frac{EF_i \times HP \times LF \times t_{event} \times n}{907,185} \quad \text{Equation (1)}$$

where:

E_{engine} are emissions of pollutant i from an engine type k [ton/pad]

EF_i is the emissions factor of pollutant i [g/hp-hr]

HP is the horsepower of the engine k [hp]

LF is the load factor of the engine k

t_{event} is the number of hours the engine is used [hr/pad]

$907,185$ is the mass unit conversion [g/ton]

n is the number of type- k engines

2.2.1.1.1 Area-Wide Annual Emissions from Source Category

Annual emissions from well pad construction equipment by pollutant were estimated from the sum of engine emissions from each of the construction engine types ($E_{engineTOTAL,i} = \sum E_{engine\ k,i}$) according to Equation 2:

$$E_{well\ pad\ equip,\ i} = E_{engineTOTAL,i} \times S_{well\ pad} \quad \text{Equation (2)}$$

where:

$E_{well\ pad\ equip}$ are annual emissions of pollutant i from well pad construction and development equipment [ton/yr]

$E_{engineTOTAL,i}$ is sum of all engine emissions per event [ton/pad]

$S_{well\ pad}$ is the scaling surrogate for well pad construction [new pads/yr]

2.2.1.1.2 Well Pad, Access Road and Pipeline Construction Traffic

This category refers to the exhaust emissions from light-duty and heavy-duty vehicle traffic during well pad, access road and pipeline construction. Emission factors were developed using the MOVES2010a model (USEPA, 2010). For each field office, by project year representative county emissions factors were developed. The emission factors were prepared for two vehicle classes, heavy duty trucks (source type combination short-haul truck) and pick-up trucks (source type light commercial truck). MOVES2010a emissions factors were modeled to include exhaust running, idle and start, brake wear, tire wear, and evaporative processes. The N₂O emission factor was obtained from 2012 Climate Registry Default Emission Factors (TCR, 2012).

The representative county for each field office and annual average per mile emission factors by county, year and vehicle type are summarized in Appendix C-6.

Emissions from two distinct fleet types were estimated in this source category dependent on the vehicle destination/use: (1) well pad and access road construction vehicles and (2) pipeline construction vehicles. Annual vehicle miles traveled (VMT) to well site were available for each vehicle class (light duty and heavy duty) within each fleet type (well pad and access road, and pipeline construction), thus exhaust emissions for each of four vehicle groups were calculated using the MOVES2010a emission factors on a grams per mile basis, as shown in Equation 3.

$$E_{traffic, i} = \frac{EF_i \times N_{trips} \times D}{907185} \quad \text{Equation (3)}$$

where:

$E_{traffic, i}$ is traffic exhaust emissions for pollutant i per well pad [ton/pad]

EF_i is the average emission factor of pollutant i [g/mile]

N_{trips} is the annual number of round trips per activity [trips/pad]

D is the round trip distance [miles/trip]

907185 is the mass conversion [g/ton]

2.2.1.2.1 Area-Wide Annual Emissions from Source Category

Annual emissions for well pad, pipeline and access road construction traffic by pollutant were propagated with the appropriate scaling surrogate according to Equation 4:

$$E_{well\ pad\ traffic, i} = E_{traffic, i} \times S_{well\ pad} \quad \text{Equation (4)}$$

where:

$E_{well\ pad\ traffic, i}$ is the annual exhaust emissions of pollutant i from well pad, pipeline and access road construction traffic [ton/yr]

$E_{traffic, i}$ are the emissions of pollutant i per new well pad [ton/wellpad]

$S_{well\ pad}$ is the scaling surrogate for well pad and access road construction traffic [new pads/yr]

2.2.1.3 Drilling, Completion and Hydraulic Fracturing Equipment

This section refers to emissions associated with off-road engines used during drilling and completion activities. Detailed data for each engine type per source category such as horsepower rating, hours of operation, fuel type, engine technology and load factors was derived from the literature. Emissions for four distinct engine groups were estimated: (1) drilling equipment, (2) completion equipment, (3) fracing equipment, and (4) refracing equipment. Emissions were estimated separately by engine type as inputs and surrogates (see Table 2-1) varied by type; however the same methodology delineated by Equations 5 and 6 was used in all calculations.

For drilling, completion and hydraulic fracturing equipment, the EPA Tier 2 Federal Diesel Engine Standard emission rates were applied for NO_x, VOC, CO, PM₁₀ and PM_{2.5} emissions. The

N₂O emissions factor was obtained from the 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17 (API, 2009). Emissions on a per event (spuds or active wells) basis for an engine type were estimated according to Equation 5:

$$E_{engine\ k,i} = \frac{EF_i \times HP \times LF \times t_{event} \times n}{907,185} \quad \text{Equation (5)}$$

where:

E_{engine} are exhaust emissions of pollutant i from an engine type k [ton/event]

EF_i is the emissions factor of pollutant i [g/hp-hr]

HP is the horsepower of the engine k [hp]

LF is the load factor of the engine k

t_{event} is the number of hours engine k is used [hr/event]

$907,185$ is the mass unit conversion [g/ton]

n is the number of type- k engines

2.2.1.3.1 Area-Wide Annual Emissions from Source Category

Annual equipment emissions by pollutant were estimated separately for each of the four engine groups and scaled with the appropriate scaling surrogate according to Equation 6:

$$E_{D\&C\ equipment,\ i} = E_{engine\ TOTAL,i} \times S_{event} \quad \text{Equation (6)}$$

where:

$E_{D\&C\ equipment,i}$ is annual emissions of pollutant i from completion/drilling equipment [ton/yr]

$E_{engine\ TOTAL,i}$ is sum of all engine emissions per event [ton/event]

S_{event} is the scaling surrogate for completion/drilling operations [event/yr] according to Table 2-1.

2.2.1.4 Drilling and Well Completion Traffic

This section refers to on-road emissions from light-duty and heavy-duty vehicle traffic during drilling and completion operations. Methodology to estimate traffic emissions from these source categories was similar to that of source category *Well Pad, Access Road and Pipeline Construction Traffic*. However, emissions for *Drilling Traffic* and *Completion Traffic* were calculated separately since activity inputs and surrogates varied by source category. Input data to estimate the annual vehicle miles traveled (VMT) per activity was derived from the literature for each vehicle class (light duty and heavy duty) within each fleet. Fleets were defined by the vehicle destination or utility, which vary by the type of oil and gas development (conventional and CBNG versus shale). These are shown in Table 2-2 below. Annual average emission factors from EPA's MOVES2010a model as described in Section 2.2.1.2 were applied.

Table 2-2. Vehicle fleets used during drilling and completion.

Vehicle Use/Destination	Vehicle Class		Fleet group ID
	Type	Class	
Drilling Traffic	Semi Trucks	Heavy Duty Truck	1
	Pickup Trucks	Light Duty Truck	2
Rig Move Drilling Traffic	Semi Trucks	Heavy Duty Truck	3
Rig Hauling	Semi Trucks	Heavy Duty Truck	4
Well Completion & Testing	Semi Trucks	Heavy Duty Truck	5
	Pickup Trucks	Light Duty Truck	6

Exhaust emissions for each of the fleet groups were calculated using the appropriate MOVES2010a emission factors on a grams per mile basis, as shown in Equation 7:

$$E_{traffic, i} = \frac{EF_i \times N_{trips} \times D}{907185} \quad \text{Equation (7)}$$

where:

$E_{traffic, i}$ is the traffic emissions for pollutant i per spud [tons/spud]

EF_i is the average emission factor of pollutant i [g/mile]

N_{trips} is the annual number of round trips per activity [trips/spud]

D is the round trip distance [miles/trip]

907185 is the mass unit conversion [g/ton]

Given that emissions from the vehicle fleets are based on the same surrogate (spuds), total emissions from drilling and completion traffic will be the sum of emissions per spud from each fleet (calculated with Equation 7), as shown in Equation 8:

$$E_{traffic,D\&C, i} = \sum_{fleet=1}^7 (E_{traffic, i})_{fleet} \quad \text{Equation (8)}$$

where

$E_{traffic,D\&C, i}$ is the total drilling and completions emissions of pollutant i per spud [ton/spud]

$E_{traffic, i}$ is the traffic emissions for pollutant i per spud for a vehicle fleet [tons/spud]

2.2.1.4.1 Area-Wide Annual Emissions from Source Category

Annual emissions for drilling/completion traffic by pollutant were propagated with the appropriate scaling surrogate (spuds per year) according to Equation 9:

$$E_{traffic, i} = E_{traffic,D\&C, i} \times S_{spud} \quad \text{Equation (9)}$$

where:

$E_{category traffic, i}$ are annual emissions of pollutant i from drilling/completion traffic [ton/yr]

$E_{traffic,D\&C, i}$ is the total drilling and completions emissions of pollutant i per spud [ton/spud]

S_{spud} is the scaling surrogate for drilling/completion traffic [spuds/yr]

2.2.1.5 Construction Equipment Fugitive Dust

Fugitive dust emissions from disturbed land by well pad construction and reclamation equipment were estimated based on AP-42 Chapter 13 Section 13.2.3 guidance for estimating emissions from Heavy Construction Operations (USEPA, 1995). A construction fugitive dust emission factor for total suspended particles (TSP) is available in the AP-42 guidance (1.2 tons-TSP/acre/month of activity).

Total suspended particle emissions from wellpad construction equipment on a per wellpad basis are estimated based on Equation 10:

$$E_{equip.dust,TSP} = EF \times A \times t \times \frac{(1-C)}{30} \quad \text{Equation (10)}$$

where:

$E_{equip,dust,TSP}$ is the TSP emissions from construction equipment fugitive dust [tons/wellpad]

A is the average number of acres disturbed per wellpad [acres/wellpad]

t is the number of construction days per wellpad [days]

C is the control efficiency

30 is the conversion factor for days/month

Conversion factors for TSP to particulate matter PM_{10} (EPA, 2006b) and from PM_{10} to $PM_{2.5}$ (Midwest Research Institute, 2006) were used to estimate other fugitive dust pollutant emissions (PM_{10} and $PM_{2.5}$). A control efficiency of 50% was assumed for well pad construction watering control.

2.2.1.5.1 Area-Wide Annual Emissions from Source Category

Annual emissions for construction equipment fugitive dust, by pollutant i , were propagated with the appropriate scaling surrogate (wellpads per year) according to Equation 11:

$$E_{equip,dust,i,TOTAL} = E_{equip.dust,i} \times S_{new pads} \quad \text{Equation (11)}$$

where:

$E_{equip,dust,i,TOTAL}$ is the annual dust emissions of pollutant i from construction equipment [ton/yr]

$E_{equip.dust,i}$ is the fugitive dust emissions of pollutant i from construction equipment per pad [tons/wellpad]

$S_{new pads}$ is the scaling surrogate for construction equipment fugitive dust [new pads/yr]

2.2.1.6 Fugitive Dust Emissions from Construction, Drilling and Completion Support Vehicles

Fugitive dust emissions from vehicle travel on unpaved roads were estimated based on the AP-42 technical guidance in Section 13.2.2.1 Unpaved Roads (USEPA, 2006a). Road dust emission factors for vehicles traveling on unpaved surfaces at industrial sites can be estimated with Equation 12.

$$EF_i = k \left(\frac{s}{12} \right)^a \left(\frac{W}{3} \right)^b \quad \text{Equation (12)}$$

where:

EF is the size-specific particulate emissions factor for pollutant i (lb/mile)

s is the surface material silt content (%)

W is the mean vehicle weight (tons)

k, a, b are empirical constants according to Table 2-3.

Table 2-3. Empirical constants by pollutant to estimate road dust emissions factor.

Parameter	PM ₁₀	PM _{2.5}
k	1.5	0.15
a	0.9	0.9
b	0.45	0.45

Because the emissions factor is a function of vehicle weight, individual emissions factor for heavy duty vehicles and light duty vehicles were derived with Equation 12. To account for natural mitigation of road dust emissions due to annual precipitation and from watering control, Equation 13 was applied:

$$EF_{mitigated} = EF_i \times \frac{365-P}{365} \times \frac{100-CE}{100} \quad \text{Equation (13)}$$

where:

$EF_{mitigated}$ is the annual average emission factor for uncontrolled conditions including natural mitigation [lb/mile]

EF_i is the size-specific emission factor [lb/mile]

P is number of precipitation days (>0.01" rainfall) at the site

CE is the control efficiency for watering in unpaved roads; $CE = 50\%$

Emissions were estimated for all types of vehicles involved in construction, drilling and completion activities. The vehicle groups were classified according to their vehicle class and utility, and literature data was collected to estimate annual vehicle miles traveled per activity (or event), which varied by vehicle groups and by the type of oil and gas development (conventional oil, conventional gas, CBNG, and shale). The vehicle fleets used in each type of development are shown in Table 2-4.

Table 2-4. Vehicles groups related to fugitive road dust emissions in well construction and development.

Vehicle group ID	Utility/destination	Vehicle Class	Event (surrogate)
1	Well Pad Access Road Construction	Heavy Duty Truck	New pads
2		Light Duty Truck	
3	Pipeline Construction	Heavy Duty Truck	
4		Light Duty Truck	

Vehicle group ID	Utility/destination	Vehicle Class	Event (surrogate)
5	Drilling Traffic	Heavy Duty Truck	Spuds
6		Light Duty Truck	
7	Rig Move Drilling Traffic	Heavy Duty Truck	New pads
8		Light Duty Truck	
9	Rig Hauling	Heavy Duty Truck	Spuds
10	Well Completion & Testing	Heavy Duty Truck	
11		Light Duty Truck	
12	Fuel Haul Truck	Heavy Duty Truck	Spuds

Fugitive dust road emissions were calculated using the mitigated emissions factor ($EF_{mitigated}$) from Equation 13, along with the vehicle miles traveled for each vehicle group as shown in Equation 14.

$$E_{traffic, i} = \frac{EF_{mitigated} \times N_{trips} \times D}{2000} \quad \text{Equation (14)}$$

where:

$E_{traffic, i}$ is the traffic fugitive dust emissions for pollutant i per event [ton/event]

$EF_{mitigated}$ is the average emission factor of pollutant i for fugitive dust emissions [lb/mile]

N_{trips} is the annual number of round trips per activity [trips/event]

D is the round trip distance [miles/trip]

2000 is the mass conversion [lb/ton]

2.2.1.6.1 Area-Wide Annual Emissions from Source Category

Annual emissions for road fugitive dust from construction/drilling/completion traffic were propagated with the appropriate scaling surrogate according to Equation 15:

$$E_{dust,traffic, i} = E_{traffic, i} \times S_{event} \quad \text{Equation (15)}$$

where:

$E_{dust,traffic, i}$ are annual emissions of pollutant i for road fugitive dust from construction/drilling/completion traffic [ton/yr]

$E_{traffic, i}$ are the emissions of pollutant i per event (spuds or new pads) [ton/event]

S_{event} is the scaling surrogate for the vehicle group [event/yr]

2.2.1.7 Construction Wind Erosion

Wind erosion dust emissions associated with well pad construction, and road, pipeline construction operations, and well pad reclamation activity were estimated based on AP-42 guidance for the estimation of emissions from industrial wind erosion (USEPA, 2006b). Wind erosion emissions per well pad were estimated based on Equation 16:

$$E_{dust,i} = \frac{P \times A \times r}{907,185} \quad \text{Equation (16)}$$

where:

$E_{dust,i}$ are dust emissions for pollutant i from construction wind erosion [ton/pad]
 P is the erosion potential [g/m^2]
 A is the well pad construction area [m^2/pad]
 r is the particle size multiplier for PM_{10} or $\text{PM}_{2.5}$
 $907,185$ is a mass unit conversion [g/ton]

The erosions potential is a function of the wind friction velocity, as shown in equation 17 and 18:

$$P = 58 \times (u^* - u_t)^2 + 25(u^* - u_t) \quad \text{Equation (17)}$$

where:

u^* is the friction velocity (m/s)
 u_t is the threshold friction velocity (m/s)

$$P = 0 \quad \text{for} \quad (u^* \leq u_t) \quad \text{Equation (18)}$$

Friction velocity estimates (u^*) were made by multiplying the average annual fastest wind speed by 0.053 per AP-42 guidance (USEPA, 2006b). Particle size multipliers of 0.5 and 0.075 were assumed for PM_{10} and $\text{PM}_{2.5}$ respectively per AP-42 guidance.

2.2.1.7.1 Area-Wide Annual Emissions from Source Category

The annual construction dust wind erosion emissions were scaled by multiplying per well pad emissions by the scaling surrogate (new pads) according to Equation 19:

$$E_{wind\ erosion\ total, i} = E_{dust, i} \times S_{well\ pad} \quad \text{Equation (19)}$$

where:

$E_{dust\ erosion\ total, i}$ are the annual emissions of pollutant i from construction dust wind erosion [ton/yr]
 $E_{dust, i}$ are the dust emissions of pollutant i per well pad [ton/pad]
 $S_{well\ pad}$ is the scaling surrogate for construction dust wind erosion [pad/yr]

2.2.1.8 Well Completion Venting

This section describes emissions from well completion venting. The calculation methodology for estimating venting emissions from a single completion event is shown below in Equation 20:

$$E_{completion,i} = \left[\frac{P \times Q_{completion}}{\frac{R}{MW_{gas}} \times T \times 3.5 \times 10^{-5}} \right] \times \frac{f_i}{907185} \times (1 - 0.95F_{flare} - F_{green}) \quad \text{Equation (20)}$$

where:

$E_{completion,i}$ is the uncontrolled emissions of pollutant i from a single completion event [ton/event]

P is atmospheric pressure [1 atm]

$Q_{completion}$ is the volume of gas generated per completion [MCF/event]

R is the universal gas constant [0.082 L-atm/mol-K]

MW_{gas} is the molecular weight of the gas [g/mol]

T is the atmospheric temperature [298 K]

f_i is the mass fraction of pollutant i in the completion venting gas

F_{green} is the fraction of completions that were controlled by green completion techniques

F_{flare} is the fraction of completions controlled by flare

0.95 is the control efficiency of the flare

2.2.1.8.1 Extrapolation to Area-Wide Annual Emissions

Annual emissions are obtained by scaling-up emissions per event by the number of spuds for a particular year. The total emissions from completion venting are estimated following Equation 21:

$$E_{completion,TOTAL,i} = E_{completion,i} \times S_{spuds} \quad \text{Equation (21)}$$

where:

$E_{completion,TOTAL}$ are the annual emissions for pollutant i from completion venting [tons/year]

$E_{completion,i}$ are the completion emissions from a single completion event [tons/event],
event=spuds

S_{spuds} is the scaling surrogate for completion venting in a particular year [spuds/year]

2.2.1.9 Well Completion Flaring

This section describes the methodology for estimating flaring emissions from completion venting as described in Equation 22. It was assumed the efficiency of the flare was 95 percent.

$$E_{flare,completion} = \left(\frac{EF_i \times Q_{completion} \times F_{flared} \times HV}{1000} \right) / 2000 \quad \text{Equation (22)}$$

where:

$E_{flare,completion}$ is the area-wide flaring emissions of pollutant i for well completions [ton/event]

EF_i is the flaring emissions factor for pollutant i [lb/MMBtu]

$Q_{completion}$ is the volume of gas generated per completion [MCF/event]

HV is the local heating value of the gas [BTU/SCF]

F_{flared} is the fraction of well completions with flares

2.2.1.9.1 Extrapolation to Area-Wide Annual Emissions

Annual area-wide flaring emissions for well completions are scaled-up using the total number of spuds per year as shown in Equation 23:

$$E_{heater, TOTAL, i} = E_{heater, i} \times S_{TOTAL} \quad \text{Equation (23)}$$

where:

$E_{heater, TOTAL}$ is the annual emissions from well completion flaring for pollutant i [[ton/yr]
 E_{heater} is the emissions from well completion flaring for pollutant i per event [ton/event]
 S_{TOTAL} is the total number of spuds for a particular year [spuds]. The number of well completions is assumed equal to the spuds count for the year.

2.2.2 Emissions from the Production Phase

Emissions from the Production phase include those generated by equipment, vehicles and activities related to oil and gas production at well sites after a well has been completed. Pollutant emissions are initially estimated on a per event basis and later scaled with the projected number of events per year (scaling surrogate) to obtain Area-wide annual emissions from each source.

2.2.2.1 Well Workovers Equipment

This category refers to emissions associated with off-road engines used during well workovers. Detailed data for a typical workover engine such as horsepower rating, hours of operation, fuel type, engine technology and load factor was derived from the literature. The EPA NONROAD2008a model (EPA, 2009b) was used to compile emission factors for ‘other oil field equipment’ representative of workover engines. The N₂O emissions factor was obtained from the 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17 (API, 2009).

Emissions on a per well basis for a workover engine were estimated according to Equation 24:

$$E_{engine, i} = f \times \frac{EF_i \times HP \times LF \times t \times n}{907,185} \quad \text{Equation (24)}$$

where:

E_{engine} are emissions of pollutant i from a workover engine [ton/well]
 EF_i is the emissions factor of pollutant i [g/hp-hr]
 HP is the horsepower of the engine [hp]
 LF is the load factor of the engine
 t is the number of hours of use per day [hr/day]
 $907,185$ is the mass unit conversion [g/ton]
 n is the number of operating days per well [days/well]
 f is the well workover frequency per year

2.2.2.1.1 Area-Wide Annual Emissions from Source Category

Annual emissions from well workover equipment by pollutant were estimated according to Equation 25:

$$E_{WO-equip, i} = E_{engine i} \times S_{wells} \quad \text{Equation (25)}$$

where:

- $E_{WO-equip, i}$ are annual emissions of pollutant i from workover equipment [ton/yr]
 $E_{engine, i}$ is emissions of pollutant i from workover equipment per well [ton/well]
 $S_{well pad}$ is the scaling surrogate for workovers [active wells/yr]

2.2.2.2 Production Traffic (Well workovers, Road Maintenance, Well Pad Reclamation and Production)

This section describes the estimation of exhaust emissions from light-duty and heavy-duty vehicle traffic used for Well Workovers, Maintenance, Well Pad Reclamation and Production. This excludes traffic from tank loading and compressor stations maintenance. Vehicle classes within the four source categories are shown in Table 2-5. Emissions from these vehicle fleets were first estimated on a per well basis and later on scaled to annual Area-wide emissions with the scaling surrogate, active wells per year.

Table 2-5. Vehicle fleets comprising production traffic.

Vehicle fleets ID	Utility (source category)	Vehicle Class	Event (surrogate)
1	Well Workover Commuting Vehicles	Light Duty Truck	Active Wells
2		Heavy Duty Truck	
3	Road Maintenance	Light Duty Truck	
4	Road and Well Pad Reclamation	Light Duty Truck	

Emission factors were developed using the MOVES2010a model as described in Section 2.2.1.2 above.

Exhaust emissions for the five vehicle groups were estimated as shown in Equation 26.

$$E_{fleet, traffic, i} = \frac{EF_i \times N_{trips} \times D}{907185} \quad \text{Equation (26)}$$

where:

- $E_{fleet, traffic, i}$ is the fleet's traffic emissions for pollutant i per well [tons/well]
 EF_i is the average emission factor of pollutant i [g/mile]
 N_{trips} is the annual number of round trips per activity [trips/well]
 D is the round trip distance [miles/trip]
 907185 is the mass unit conversion [g/ton]

2.2.2.2.1 *Area-Wide Annual Emissions from Source Category*

Annual emissions for each category (fleet) of production traffic were propagated with the appropriate scaling surrogate (active wells per year) according to Equation 27:

$$E_{fleet, TOTAL, i} = E_{fleet, traffic, i} \times S_{wells} \quad \text{Equation (27)}$$

where:

$E_{fleet,TOTAL,i}$ are annual emissions of pollutant i from a production fleet [ton/yr]

$E_{fleet,traffic,i}$ is the emissions of pollutant i per well for a production traffic fleet [ton/well]

S_{wells} is the scaling surrogate for the source category [active wells/yr]

2.2.2.3 Fugitive Dust Emissions from Production Traffic (Well Workovers, Road Maintenance, Well Pad Reclamation and Other Production)

Fugitive dust emissions from vehicle travel on unpaved roads were estimated based on the AP-42 technical guidance Section 13.2.2.1 Unpaved Roads (EPA, 2006a). Road dust emission factors for vehicles traveling on unpaved surfaces at industrial sites can be estimated with Equation 28.

$$EF_i = k \left(\frac{s}{12} \right)^a \left(\frac{W}{3} \right)^b \quad \text{Equation (28)}$$

Where:

EF is the size-specific particulate emissions factor for pollutant i (lb/mile)

s is the surface material silt content (%)

W is the mean vehicle weight (tons)

k, a, b are empirical constants according to Table 2-6.

Table 2-6. Empirical constants by pollutant to estimate road dust emissions factor.

Parameter	PM ₁₀	PM _{2.5}
k	1.5	0.15
a	0.9	0.9
b	0.45	0.45

Because the emissions factor is a function of vehicle weight, individual emissions factor for heavy duty vehicles and light duty vehicles were calculated with Equation 28. To account for natural mitigation of road dust emissions due to annual precipitation and from watering control, Equation 29 was applied:

$$EF_{mitigated} = EF_i \times \frac{365-P}{365} \times \frac{100-CE}{100} \quad \text{Equation (29)}$$

Where:

$EF_{mitigated}$ is the annual average emission factor for uncontrolled conditions including natural mitigation [lb/mile]

EF_i is the size-specific emission factor [lb/mile]

P is number of precipitation days (>0.01" rainfall) at the site

CE is the control efficiency for watering in unpaved roads

Vehicle fleets comprising production traffic are shown in Table 2-5. Fugitive dust emissions from these vehicle fleets were first estimated on a per well basis and later scaled to annual Area-wide emissions with the scaling surrogate, active wells per year.

Fugitive dust road emissions per well were calculated using the mitigated emissions factor ($EF_{mitigated}$) from Equation 29, along with the vehicle miles traveled for each vehicle group. This is shown in Equation 30

$$E_{fleet,traffic,i} = \frac{EF_{mitigated} \times N_{trips} \times D}{2000} \quad \text{Equation (30)}$$

where:

$E_{fleet,traffic,i}$ is the traffic fugitive dust emissions for pollutant i per well [ton/well]

$EF_{mitigated}$ is the average emission factor of pollutant i for fugitive dust emissions [lb/mile]

N_{trips} is the annual number of round trips per activity [trips/well]

D is the round trip distance [miles/trip]

2000 is the mass conversion [lb/ton]

2.2.2.3.1 Area-Wide Annual Emissions from Source Category

Annual fugitive dust emissions for each category (fleet) of Production traffic were propagated with the appropriate scaling surrogate (active wells per year) according to Equation 31:

$$E_{fleet,TOTAL,i} = E_{fleet,traffic,i} \times S_{wells} \quad \text{Equation (31)}$$

where:

$E_{fleet,TOTAL,i}$ are annual fugitive dust emissions of pollutant i from a production fleet [ton/yr]

$E_{fleet,traffic,i}$ is the fugitive dust emissions of pollutant i per well for a production traffic fleet [ton/well]

S_{wells} is the scaling surrogate for the source category [active wells/yr]

2.2.2.4 Blowdown venting

This section refers to the estimation of emissions from venting during well blowdowns. The calculation methodology for estimating emissions from a single blowdown event is shown below in Equation 32:

$$E_{blowdown,i} = \left(\frac{P \times (V_{vented})}{\left(\frac{R}{MW_{gas}} \right) \times T \times 3.5 \times 10^{-5}} \right) \times \frac{f_i}{907185} \quad \text{Equation (32)}$$

where:

$E_{blowdown,i}$ is the emissions of pollutant i from a single blowdown event [ton/event]

P is atmospheric pressure [1 atm]

V_{vented} is the volume of vented gas per blowdown (uncontrolled) [MCF/event]
 R is the universal gas constant [0.082 L-atm/mol-K]
 MW_{gas} is the molecular weight of the gas [g/mol]
 T is the atmospheric temperature [298 K]
 f_i is the mass fraction of pollutant i in the vented gas

2.2.2.4.1 Area-Wide Annual Emissions from Source Category

The total emissions from all annual blowdowns events occurring are estimated with Equation 33:

$$E_{blowdown, TOTAL} = E_{blowdown, i} \times N_{blowdown} \times S_{wells} \quad \text{Equation (33)}$$

where:

$E_{blowdown, TOTAL}$ are the total annual emissions from blowdowns [tons/yr]
 $E_{blowdown, i}$ are the blowdown emissions from a single blowdown event [tons/event]
 $N_{blowdown}$ is the frequency of blowdowns per well per year [events/yr-well]
 S_{wells} is the total number of active wells for a particular year [wells]

2.2.2.5 Well Recompletion Venting

This section describes emissions from well recompletion venting. The calculation methodology for estimating venting emissions from a single recompletion event is shown below in Equation 34:

$$E_{recompletion, i} = \left[\frac{P \times Q_{recompletion}}{\frac{R}{MW_{gas}} \times T \times 3.5 \times 10^{-5}} \right] \times \frac{f_i}{907185} \quad \text{Equation (34)}$$

where:

$E_{recompletion, i}$ is the uncontrolled emissions of pollutant i from a single recompletion event [ton/event]
 P is atmospheric pressure [1 atm]
 $Q_{recompletion}$ is the volume of gas generated per recompletion [MCF/event]
 R is the universal gas constant [0.082 L-atm/mol-K]
 MW_{gas} is the molecular weight of the gas [g/mol]
 T is the atmospheric temperature [298 K]
 f_i is the mass fraction of pollutant i in the recompletion venting gas

2.2.2.5.1 Extrapolation to Annual Area-Wide Emissions

Annual emissions are obtained by scaling-up emissions per event with the total number of recompletion events in a particular year. The total emissions from recompletion venting are estimated following Equation 35:

$$E_{recompletion, TOTAL, i} = E_{recompletion, i} \times f \times S_{well\ count} \quad \text{Equation (35)}$$

where:

$E_{completion, TOTAL}$ are the annual emissions for pollutant i from recompletion venting [tons/year]

$E_{completion, i}$ are the venting emissions from a single recompletion event [tons/event]

f is the frequency of recompletion events per well per year [events/yr-well]

$S_{well\ count}$ is the scaling surrogate for recompletion venting in a particular year [active wells]

2.2.2.6 Wellhead Fugitives

This source category refers to fugitive emissions or *leaks* from well equipment such as pump seals, valves, connectors, flanges, etc. Fugitive emissions were estimated for three main streams identified: gas service stream, liquids service stream and high oil stream. VOC, CO₂ and CH₄ emissions per stream were estimated using device-specific TOC emission factors for oil and gas production (USEPA, 1995b) and equipment counts. Input data was obtained from the literature on total device counts per well by type of equipment and by the type of service to which the equipment applies – gas, liquids and high oil.

Fugitive VOC emissions for an individual device in a given stream (gas, liquids, and high oil) were estimated according to Equation 36:

$$E_{fugitiveVOC, k} = EF_{TOC} \times N \times t_{annual} \times Y \quad \text{Equation (36)}$$

where:

$E_{fugitiveVOC, k}$ is the fugitive VOC emissions for a given device k [ton/yr-well]

EF_{TOC} is the emission factor of TOC [kg/hr/device]

N is the total number of devices type- k for a given stream per well [devices/well]

Y is the ratio of VOC to TOC in the vented gas

Total VOC fugitive emissions for a given stream are equal to the sum of all fugitive emissions from devices in that stream per Equation 37:

$$E_{fugitiveVOC, stream} = \sum E_{fugitiveVOC, k} \quad \text{Equation (37)}$$

where:

$E_{fugitiveVOC, stream}$ is the total fugitive VOC emissions in a given stream per well [ton/yr-well]

CO₂ and CH₄ fugitive emissions per stream were estimated according to Equations 38 and 39:

$$E_{fugitiveCH4, stream} = E_{fugitiveVOC, stream} \times \frac{\text{weight fraction}_{CH4}}{\text{weight fraction}_{VOC}} \quad \text{Equation (38)}$$

$$E_{fugitiveCO2, stream} = E_{fugitiveVOC, stream} \times \frac{\text{weight fraction}_{CO2}}{\text{weight fraction}_{VOC}} \quad \text{Equation (39)}$$

where:

$E_{fugitiveCO2, stream}$ is the total fugitive CO₂ emissions in a given stream per well [ton/yr-well]

$E_{fugitive\ CH_4, stream}$ is the total fugitive CH₄ emissions in a given stream per well [ton/yr-well]
Weight fractions per pollutant were based on gas compositions. For gas and well streams, sales gas composition was used. For condensate stream, fugitive-post flash compositions were used.

2.2.2.6.1 Area-Wide Annual Emissions from Source Category

Fugitive emissions were propagated annually according to Equation 40 using the scaling surrogate, active well counts:

$$E_{fugitive, i} = E_{fugitive\ i, stream} \times S_{well\ count} \quad \text{Equation (40)}$$

where:

$E_{fugitive, i}$ are the annual fugitive emissions for pollutant i in a given stream [ton/yr]
 $E_{fugitive\ i, stream}$ are fugitive emissions of pollutant i in a stream per well [ton/yr-well]
 $S_{well\ count}$ is the number of active wells for a particular year [active wells]

2.2.2.7 Pneumatic Devices

Emissions for pneumatic devices will vary by the bleed rate of the device. The methodology for estimating the emissions from a mix of pneumatic devices i (liquid level controllers, pressure controllers, etc.) for a single typical well is shown in Equation 41:

$$E_{pneumatic, j} = \frac{f_j}{907185} \left(\sum_i \dot{V}_i \times N_i \times t_{annual} \right) \times \frac{P}{\left(\left(\frac{R}{MW_{gas}} \right) \times T \times 3.5 \times 10^{-5} \right)} \quad \text{Equation (41)}$$

where:

$E_{pneumatic, j}$ is the total emissions of pollutant j from all pneumatic devices for a typical well [ton/year/well]
 \dot{V}_i is the volumetric bleed rate from device i [MCF/hr/device]
 N_i is the average number of devices i found in a well [devices/well]
 t_{annual} is the number of hours per year that devices were operating [8760 hr/yr]
 P is the atmospheric pressure [1 atm]
 R is the universal gas constant [0.082 L-atm/mol-K]
 MW_{gas} is the molecular weight of the gas [g/mol]
 T is the atmospheric temperature [298 K]
 f_j is the mass fraction of pollutant j in the vented gas

2.2.2.7.1 Extrapolation to Area-Wide Annual Emissions

Annual emissions from pneumatic devices were estimated according to Equation 42:

$$E_{pneumatic\ ,TOTAL\ ,j} = E_{pneumatic\ ,j} \times N_{well} \quad \text{Equation (42)}$$

where:

$E_{pneumatic,TOTAL,j}$ is the total annual emissions of pollutant j from pneumatic devices [ton/yr]

$E_{pneumatic,j}$ is the pneumatic device emissions of pollutant j for a single typical well [ton/yr/well]

N_{well} is the total number of active wells in the basin [wells]

2.2.2.8 Pneumatic Pumps

To estimate emissions from pneumatic pumps, literature data indicating the average rate of gas consumption per gallon of chemical injected and the annual chemical throughput for a single pump was applied. Emissions per well from pneumatic pumps were estimated as shown in Equation 43:

$$E_{pump,i} = \frac{N_{CIP} \times V_{vented,gas} \times t_{pump} \times MW_i \times R \times Y_i}{2000} \quad \text{Equation (43)}$$

where:

$E_{pump,i}$ is the pneumatic pump emissions for pollutant i per well [ton/yr-well]

$V_{vented,TOTAL}$ is the average gas venting rate per pump [SCF/pump/hr]

N_{CIP} is the number of gas-actuated pneumatic pumps per well [pump/well]

t_{pump} is the annual hours of operation of a pump [hrs/yr]

MW_i is the molecular weight of pollutant i [lb/lb-mol]

R is the universal gas constant [lb-mol/391.9scf]

Y_i is the molar fraction of pollutant i in pneumatic pump vented gas

2000 is the mass unit conversion [lb/ton]

2.2.2.8.1 Area-Wide Annual Emissions from Source Category

To estimate area-wide annual emissions from pneumatic pumps the scaling surrogate, active wells, was used according to Equation 44

$$E_{pneumaticpumps,i} = E_{pump,i} \times S_{well\ count} \quad \text{Equation (44)}$$

where:

$E_{pneumaticpumps,i}$ are the annual emissions for pollutant i from pneumatic pumps [ton/yr]

$E_{pump,i}$ is the emissions from all pneumatic pumps per well [ton/yr-well]

$S_{well\ count}$ is the number of active wells for a particular year [wells]

2.2.2.9 Water Injection Pumps

This category refers to exhaust emissions associated with diesel combustion in water injection pump engines. Detailed data for each engine type such as horsepower rating, hours of operation, fuel type, engine technology and load factors was derived from the literature. The EPA NONROAD2008a model (USEPA, 2009b) was used to compile emission factors. The N_2O emissions factor was obtained from the 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17 (API, 2009).

Emissions on a per well basis for a water injection pump were estimated according to Equation 45:

$$E_{engine,i} = \frac{EF_i \times HP \times LF \times t_{event} \times n}{907,185} \quad \text{Equation (45)}$$

where:

E_{engine} are per-well emissions of pollutant i from water injection pumps [ton/well]

EF_i is the emissions factor of pollutant i [g/hp-hr]

HP is the horsepower of the pump [hp]

LF is the load factor of the pump

t_{event} is the number of hours the engine is used annually [hrs/unit]

$907,185$ is the mass unit conversion [g/ton]

n is the number of water injection pumps per well [units/well]

2.2.2.9.1 Area-Wide Annual Emissions from Source Category

Annual emissions from water injection pumps for pollutant i were estimated according to Equation 46:

$$E_{water\ pumps, i} = E_{engine, i} \times S_{well} \quad \text{Equation (46)}$$

where:

$E_{well\ pad\ equip}$ are annual emissions of pollutant i from water injection pumps [ton/yr]

$E_{engine, i}$ is engine emissions per well [ton/well]

S_{well} is the scaling surrogate for water injection pumps [active wells/yr]

2.2.2.10 Miscellaneous Engines

This category refers to exhaust emissions associated with miscellaneous engines at well sites. Detailed data for miscellaneous engines such as horsepower rating, hours of operation, fuel type, engine technology and load factors was derived from the literature. The EPA NONROAD2008a model (USEPA, 2009b) was used to compile emission factors. The N_2O emissions factor was obtained from the 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17 (API, 2009).

Emissions on a per well basis for miscellaneous engines were estimated according to Equation 47:

$$E_{engine,i} = \frac{EF_i \times HP \times LF \times t_{event} \times n}{907,185} \times f \quad \text{Equation (47)}$$

where:

E_{engine} are per-well emissions of pollutant i from miscellaneous engines [ton/well]

EF_i is the emissions factor of pollutant i [g/hp-hr]

HP is the horsepower of the pump [hp]

LF is the load factor of the pump

t_{event} is the number of hours the engine is used [hrs/unit]

f is the fraction of wells served by a miscellaneous engine
 $907,185$ is the mass unit conversion [g/ton]
 n is the number of engines per well [units/well]

2.2.2.10.1 Area-Wide Annual Emissions from Source Category

Annual emissions from miscellaneous engines for pollutant i were estimated according to Equation 48:

$$E_{water\ pumps, i} = E_{engine, i} \times S_{well} \quad \text{Equation (48)}$$

where:

$E_{well\ pad\ equip}$ are annual emissions of pollutant i from miscellaneous engines [ton/yr]
 $E_{engine, i}$ is engine emissions per well [ton/well]
 S_{well} is the scaling surrogate for miscellaneous engines [active wells/yr]

2.2.2.11 Compressor Station Maintenance Traffic Exhaust

This section describes the estimation of exhaust emissions from light-duty vehicles (pickup trucks) used for compressor maintenance at compressor stations. Emission factors were developed using the MOVES2010a model (USEPA, 2010) as described in Section 2.2.1.2. The total vehicle miles travelled annually from maintenance visits to a single compressor station were obtained from the literature.

Exhaust emissions for this fleet were estimated as shown in Equation 49.

$$E_{fleet, traffic, i} = \frac{EF_i \times VMT_{CS}}{907185} \quad \text{Equation (49)}$$

where:

$E_{fleet, traffic, i}$ is the fleet's traffic emissions for pollutant i per well [tons/station]
 EF_i is the average emission factor for light duty vehicles of pollutant i [g/mile]
 VMT_{CS} is the annual miles travelled for maintenance compressor station [miles/station]
 907185 is the mass unit conversion [g/ton]

2.2.2.11.1 Area-Wide Annual Emissions from Source Category

Annual emissions for the compressor maintenance fleet were propagated with the scaling surrogate "total count of active compressor stations" according to Equation 50:

$$E_{fleet, TOTAL, i} = E_{fleet, traffic, i} \times S_{CS} \quad \text{Equation (50)}$$

where:

$E_{fleet, TOTAL, i}$ are annual emissions of pollutant i from compressor station maintenance traffic [ton/yr]
 $E_{fleet, traffic, i}$ is the emissions of pollutant i per station for the fleet [ton/station]
 S_{CS} is the scaling surrogate for the source category [number of active compressor stations per year]

2.2.2.12 Fugitive Dust Emissions from Compressor Station Maintenance Traffic

Road dust emission factors for light duty vehicles traveling on unpaved surfaces to and from compressor stations were estimated with the same methodology as in Section 2.2.1.2.6 using Equations 28 and 29. Fugitive dust road emissions per station (visited) were calculated using the mitigated emissions factor ($EF_{mitigated}$) from Equation 29, along with the annual vehicle miles traveled per compressor station. This is shown in Equation 51.

$$E_{fleet,traffic, i} = \frac{EF_{mitigated} \times VMT}{2000} \quad \text{Equation (51)}$$

where:

$E_{fleet,traffic, i}$ is the traffic fugitive dust emissions for pollutant i per station [ton/station]

$EF_{mitigated}$ is the average emission factor of pollutant i for fugitive dust emissions [lb/mile]

VMT is the annual miles travelled for maintenance compressor station [miles/station]

2000 is the mass conversion [lb/ton]

2.2.2.12.1 Area-Wide Annual Emissions from Source Category

Annual fugitive dust emissions for compressor station maintenance traffic were propagated with the “total number of compressor stations” according to Equation 52:

$$E_{fleet,TOTAL,i} = E_{fleet,traffic, i} \times S_{CS} \quad \text{Equation (52)}$$

where:

$E_{fleet,TOTAL, i}$ are annual fugitive dust emissions of pollutant i from compressor station maintenance traffic [ton/yr]

$E_{fleet,traffic, i}$ is the emissions of pollutant i per station for the fleet [ton/station]

S_{CS} is the scaling surrogate for the source category [number of active compressor stations per year]

2.2.2.13 Condensate Tanks Flashing

Condensate tank emissions were calculated differently for conventional oil and gas developments and for shale gas developments.

An uncontrolled VOC emissions factor applicable to Garfield, Mesa, Rio Blanco, and Moffat Counties (CDPHE, 2011) was used to estimate emissions for condensate tanks in conventional gas, shale gas and coalbed natural gas developments on a per barrel basis. The published emissions factor was 10 lbs VOC/bbl [0.005 tons/bbl]; for planning areas outside of those counties the emission factor of 11.3 lbs VOC/bbl [0.008 tons/bbl] can be used (CDPHE, 2011). For conventional oil developments, the emissions factor of 1.6 lbs VOC/bbl was used based on BLM (2013). The VOC emissions factor was multiplied by the annual condensate production from each type of well to propagate VOC emissions to the Planning Area level for each year.

Similar to the methodology for conventional oil and gas sources, CO₂ and CH₄ total emissions were then calculated using the weight fraction ratios from local flash gas composition analyses using Equations 53 and 54.

$$E_{tanks,CH_4} = E_{tanks,VOC} \times \frac{weight\ fraction_{CH_4}}{weight\ fraction_{VOC}} \quad \text{Equation (53)}$$

$$E_{tanks,CO_2} = E_{tanks,VOC} \times \frac{weight\ fraction_{CO_2}}{weight\ fraction_{VOC}} \quad \text{Equation (54)}$$

where:

$E_{tanks,VOC}$ is the total annual condensate tanks emissions from APENS database [tons/yr]

E_{tanks,CO_2} is the total condensate tank CO₂ emissions [tons/yr]

E_{tanks,CH_4} is the total condensate CH₄ emissions [tons/yr]

Weight fractions of each pollutant in flash gas

2.2.2.14 Loading Emissions from Condensate or Oil Tanks

This section describes emissions from truck loading of condensate or crude oil from tanks. The loading loss rate is estimated following Equation 55:

$$L = 12.46 \times \left(\frac{S \times V \times M}{T} \right) \quad \text{Equation (55)}$$

where:

L is the loading loss rate [lb/1000gal]

S is the saturation factor taken from AP-42 default values based on operating mode. The operating mode for loading assumed was submerged loading: dedicated normal service.

V is the true vapor pressure of the liquid loaded [psia]

M is the molecular weight of the vapor [lb/lb-mole]

T is the temperature of the bulk liquid [°R], $T=540$ R

VOC tank loading emissions are then estimated by Equation 56:

$$E_{loading, VOC} = L \times Y_{voc} \times \frac{42}{2000} \quad \text{Equation (56)}$$

where:

$E_{loading}$ are the VOC tank loading emissions [ton/bbl]

L is the loading loss rate [lb/1000gal]

Y_{VOC} is the weight fraction of VOC in the vapor in the liquid loaded

42 is a unit conversion [gal/bbl]

2000 is a unit conversion [lbs/ton]

CO₂ and CH₄ emissions are calculated based on Equations 57-58:

$$E_{loading,CH_4} = E_{loading,VOC} \times \frac{weight\ fraction_{CH_4}}{weight\ fraction_{VOC}} \quad \text{Equation (57)}$$

$$E_{loading,CO_2} = E_{loading,VOC} \times \frac{weight\ fraction_{CO_2}}{weight\ fraction_{VOC}} \quad \text{Equation (58)}$$

where:

$E_{loading,CO_2}$ is the total loading CO₂ emissions per barrel of liquid [ton/bbl]

$E_{loading,CH_4}$ is the total loading CH₄ emissions per barrel of liquid [ton/bbl]

Weight fractions of each pollutant in the vapor losses from the liquid loaded

2.2.2.14.1 Area-Wide Annual Emissions from Source Category

Annual emissions per pollutant *i* from condensate loading were scaled by annual condensate production per Equation 59:

$$E_{tank\ loadout,\ i} = E_{loading,\ i} \times S_{bbl\ condensate} \quad \text{Equation (59)}$$

where:

$E_{tank\ loadout,\ i}$ is the total condensate loading emissions for pollutant *i* from tank load-out [ton/yr]

$E_{loading,\ i}$ is the condensate loading emissions for pollutant *i* from per barrel [ton/bbl]

$S_{bbl\ condensate}$ is the total annual of barrels condensate [bbl/yr]

2.2.2.15 Condensate, Crude Oil and Produced Water Hauling Traffic Exhaust

This section describes the estimation of exhaust emissions from heavy-duty vehicles (haul trucks) used for produced condensate hauling from the well site. Emission factors were developed using the MOVES2010a model (EPA, 2010) as described in Section 2.2.1.2. The total round trip distance for each hauling trip was derived from the literature. A hauling volume of per truck of 200 barrels of condensate or crude oil, hence the number of round trips per barrel was estimated (1/200).

Exhaust emissions for condensate and crude oil hauling fleet were estimated as shown in Equation 60a.

$$E_{fleet,traffic,\ i} = \frac{EF_i \times N_{trips} \times D}{907185} \quad \text{Equation (60a)}$$

where:

$E_{fleet,traffic,\ i}$ is the hauling traffic exhaust emissions for pollutant *i* per barrel [ton/bbl]

EF_i is the average emission factor of pollutant *i* for heavy duty vehicles [g/mile]

N_{trips} is the annual number of round trips per barrel [trips/bbl]. $N=1/200$

D is the round trip distance [miles/trip]

907185 is the mass conversion [g/ton]

2.2.2.15.1 Area-Wide Annual Emissions from Condensate or Crude Oil Hauling

Annual emissions for the condensate and crude oil hauling fleet were propagated with the annual condensate or crude oil production according to Equation 61a:

$$E_{fleet,TOTAL,i} = E_{fleet,traffic,, i} \times S_{bbl,condensate} \quad \text{Equation (61a)}$$

where:

$E_{fleet,TOTAL,i}$ are annual emissions of pollutant i from condensate hauling traffic [ton/yr]
 $E_{fleet,traffic,, i}$ is the emissions of pollutant i per barrel for the hauling fleet [ton/bbl]
 $S_{bbl,condensate}$ is the scaling surrogate for the source category [barrels of condensate produced per year]

2.2.2.15.2 Produced water hauling exhaust emissions

Produced water refers to the water produced with the gas once the well has been completed and is under operation. This water is typically hauled from the well site storage tanks with water trucks or sent via pipeline to injection wells. Annual produced water rates will vary by the type of well. It was assumed that the annual rate of water production for conventional oil, conventional gas and shale gas wells was 18,250 bbl/well (URS, 2012a); this value can be updated for a given area based on Colorado Oil and Gas Conservation Commission water production data. It was assumed that produced water truck capacity is 130 bbl and that 50 percent of the water is hauled out.

The annual water production per CBNG well was assumed to be 97,900 bbl/well (BLM, 2012); this value can be updated for a given area based on Colorado Oil and Gas Conservation Commission water production data.

Exhaust emissions for produced water hauling fleet were estimated as shown in Equation 60b:

$$E_{fleet,traffic,, i} = \frac{EF_i \times N_{trips} \times D}{907185} \quad \text{Equation (60b)}$$

where:

$E_{fleet,traffic,, i}$ is the produced water hauling exhaust emissions for pollutant i per well [ton/well]
 EF_i is the average emission factor of pollutant i for heavy duty vehicles [g/mile]
 N_{trips} is the annual number of round trips per well [trips/well]
 D is the round trip distance [miles/trip]
 907185 is the mass conversion [g/ton]

2.2.2.15.2.1 Area-Wide Annual Emissions from Produced Water Hauling

Annual emissions for the produced water hauling fleet were propagated to the planning area according to Equation 61b:

$$E_{fleet,TOTAL,i} = E_{fleet,traffic,, i} \times S_{active wells} \quad \text{Equation (61b)}$$

where:

$E_{fleet,TOTAL,i}$ are annual emissions of pollutant i from produced water hauling traffic [ton/yr]
 $E_{fleet,traffic,, i}$ is the emissions of pollutant i per well for the hauling fleet [ton/well]
 $S_{active wells}$ is the scaling surrogate for the source category, active wells per year [wells/yr]

2.2.2.15.3 Fugitive Dust Emissions from Condensate and Produced Water Hauling Traffic

Road dust emission factors for heavy duty vehicles traveling on unpaved surfaces for condensate hauling and produced water hauling were estimated with the same methodology as in Section 2.2.1.2.6 using Equations 28 and 29. Because the number of trips for both of these activities is based on different surrogates - per barrel for condensate hauling and per well for produced water hauling - as shown in Section 2.2.1.2.15, fugitive dust road emissions of each fleet were calculated using the mitigated emissions factor ($EF_{mitigated}$) from Equation 29. This is shown in Equation 62.

$$E_{fleet,traffic,i} = \frac{EF_{mitigated} \times D \times N_{trips}}{2000} \quad \text{Equation (62)}$$

where:

$E_{fleet,traffic,i}$ is the traffic fugitive dust emissions for pollutant i per (1) barrel of condensate [ton/bbl] for condensate hauling or (2) well [ton/well] for produced water hauling

$EF_{mitigated}$ is the average emission factor of pollutant i for fugitive dust emissions [lb/mile]

N_{trips} is the annual number of round trips per (1) barrel of condensate hauled [trips/bbl] for condensate hauling or (2) well [trips/well] for produced water hauling

D is the round trip distance per hauling trip [miles/trip]

2000 is the mass conversion [lb/ton]

2.2.2.15.3.1 Area-Wide Annual Emissions from Condensate and Produced Water Hauling Traffic
Annual fugitive dust emissions for condensate hauling were propagated with the annual condensate production according to Equation 63:

$$E_{fleet,TOTAL,i} = E_{fleet,traffic,i} \times S_{bbl,condensate \text{ or } active \text{ wells}} \quad \text{Equation (63)}$$

where:

$E_{fleet,TOTAL,i}$ are annual fugitive dust emissions of pollutant i from condensate hauling traffic [ton/yr]

$E_{fleet,traffic,i}$ is the dust emissions of pollutant i per barrel for the hauling fleet [ton/surrogate]

$S_{bbl,condensate \text{ or } active \text{ wells}}$ is the scaling surrogate for the source category: (1) [barrels of condensate produced per year] for condensate hauling or (2) [active wells per year] for produced water hauling

2.2.2.16 Heaters

This section describes the methodology for estimating emissions from heaters and reboilers. Heater emissions are a function of the properties of the local produced gas used as a fuel. Emissions factors for external combustion of natural gas were obtained from AP-42 Section 1.4 Natural Gas Combustion (USEPA, 1995a). Emissions per well from heaters and reboilers can be estimated individually using Equation 64.

$$E_{heater,i} = N_{heaters} \times \frac{EF_i \times Q_{heater} \times t_{annual}}{(HV_{local} \times 2000)} \quad \text{Equation (64)}$$

where:

$E_{heater,i}$ is the per well emissions for pollutant from a given heater [ton/well-yr]

EF_i is the heater emission factor for a given pollutant i [lb/MM SCF]

Q_{heater} is the heater MMBTU/hr rating [MMBTU_{rated}/hr]

HV_{local} is the local natural gas heating value [BTU_{local}/SCF]

t_{annual} is the annual hours of operation [hr/yr]

$N_{heaters}$ is the number of heaters per well

2.2.2.16.1 Area-Wide Annual Emissions from heaters

Annual emissions for heaters and reboilers are estimated with Equation 65 using the scaling surrogate active wells.

$$E_{heater,TOTAL,i} = E_{heater,i} \times W_{TOTAL} \quad \text{Equation (65)}$$

where:

$E_{heater,TOTAL}$ is the total emissions of pollutant i for a given heater type in the Project [ton/yr]

E_{heater} is the per well annual emissions from a given heater type for pollutant i [ton/well-yr]

W_{TOTAL} is the total number of wells for a particular year [wells]

2.2.2.17 Dehydrator Emissions

This section describes the methodology to estimate emissions from dehydrator still vents. Uncontrolled emission factors per unit of gas production for emissions of VOC, CH₄ and CO₂ were derived from the literature for the various well types. Total emissions were propagated using the gas production by well type, assuming 100 percent of the gas undergoes well site dehydration. This was done applying Equation 66.

$$E_{dehyTOTAL,i,j} = EF_{dehy,i} \times S_{gas\ production,j} \quad \text{Equation (66)}$$

where:

$E_{dehy,TOTAL,i,j}$ are the total area-wide emissions from dehydrators still vents for pollutant i in year j [tons/yr]

$EF_{dehy,i}$ is the dehydrator still vent emissions rate [tons/MCF]

$S_{gas\ production}$ is the annual gas production in year j [MCF/yr]

2.2.3 Midstream sources

Midstream sources include gathering and treating emissions associated with facilities such as compressor stations and gas plants. Midstream emissions are taken from the 2011 APEN (Air Pollutant Emission Notice) emissions database provided by CDPHE (CDPHE, 2013). CDPHE

provided APEN emissions for all oil and gas related emission sources covered by the following SCC and SIC codes:

- All of the SCCs 202002*, 310*, 404003* (where * indicates all sub-SCCs for the SCC)
- And only those with the following SICs: 13*, 492*, 4612

BLM field office planning area designation was assigned according to the latitude and longitude of each source. The APEN oil and gas emissions database includes both well site and midstream sources. Midstream sources were identified for inclusion in the calculator based on the facility name and the suite of equipment included at a given facility. Appendix C-2 includes a table of emissions by facility for each field office area.

Emissions were available in the APEN emissions database for the pollutants VOCs, CO, NO_x, PM₁₀ and SO₂ in tons per year. Emissions for CH₄ and CO₂ were calculated using the vented gas speciation according to Equations 67 and 68 for the following sources.

- Glycol Dehydrator
- Natural Gas Processing Facilities, Gas Sweetening: Amine Process
- Condensate Tanks
- Natural Gas Processing Facilities, Flanges and Connections

$$E_{source,CH_4} = E_{tanks,VOC} \times \frac{weight\ fraction_{CH_4}}{weight\ fraction_{VOC}} \quad \text{Equation (67)}$$

$$E_{source,CO_2} = E_{tanks,VOC} \times \frac{weight\ fraction_{CO_2}}{weight\ fraction_{VOC}} \quad \text{Equation (68)}$$

where:

$E_{source,VOC}$ is the total annual emissions from APENS database *a source* [tons/yr]

E_{source,CO_2} is the total CO₂ emissions from *a source* [tons/yr]

E_{source,CH_4} is the total CH₄ emissions from *a source* [tons/yr]

Weight fractions of each pollutant in the vented gas

For combustion sources such as compressor engines, process heaters and flares, emissions for CH₄, N₂O and CO₂ were estimated using the ratios of each greenhouse gas to NO_x of emissions factors from AP-42.

Emissions in future years were estimated by multiplying 2011 emissions by the ratio of gas production in a given future year to gas production in 2011.

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APPENDIX C-1

Conventional Gas Well Calculator Inputs by Source Category

Note: Yellow highlights indicate that inputs were obtained from the Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012. All inputs taken from other sources are noted.

Gas Analysis & Venting		Speciated Sales Gas Analysis	
Gas Component		Mole Fraction	
		(%)	
Methane C1		81.012	
Ethane C2		4.334	
Nitrogen		6.718	
Water		0.000	
Carbon Dioxide		5.380	
Nitrous Oxide		0.000	
Hydrogen Sulfide		0.000	
Propane C3		1.437	
i-Butane i-C4		0.288	
n-Butane n-C4		0.329	
i-Pentane iC5		0.154	
n-Pentane nC5		0.104	
Hexanes C6		0.111	
Heptanes C7		0.037	
Octanes+		0.017	
Benzene		0.004	
Ethylbenzene		0.000	
n-Hexane n-C6		0.068	
Toluene		0.003	
2,2,4-Trimethylpentane		0.001	
Xylenes		0.002	

Cn_HEq_Exh Construction/Drilling/Completion Equipment

Construction Equipment

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/Well Pad	Equipment Category	HP Range
Well Pad	Construction Equipment	250	4	42	10	13	Other Construction Equipment	300
Well Pad Access Road	Construction Equipment	250	4	42	10	10	Other Construction Equipment	300
Pipeline	Construction Equipment	250	2	42	10	2	Other Construction Equipment	300

Construction Site	Equipment Type	2011 Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Well Pad	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Well Pad Access Road	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Pipeline	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00

Source: EPA NONROADS 2008a
 ^aN2O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Drilling

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range for Efs
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	2469	2	40	24	17	2270010010	Tier 2	>1200

Construction Site	Equipment Type	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N2O ^a
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Source: EPA Federal Tier Standards

^aN2O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Completion/Fracing

Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range
Completion Equipment	1230	1	40	7	1	2270010010	Tier 2	>1200
Fracing Equipment	12000	1	85	24	1	2270010010	Tier 2	>1200
Refracing Equipment	1500	4	97	1	3	2270010010	Tier 2	>1200

Grand Junction Field Office Air Quality Technical Support Document, ENVIRON, 2012

Data updated from White River Air Quality Technical Support Document, URS, 2012 (Fracing Equipment), and from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012 (Completion)

Equipment Type	Capacity (hp)	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Completion Equipment	1230	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Fracing Equipment	12000	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Refracing Equipment	1500	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002

Source: EPA Federal Tier Standards
^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Fracing frequency per spud	1
Refracing Frequency per Year per Well	0.05

Cn_CV_Exh Construction Traffic Exhaust

Well Pad and Access Road Construction Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well Pad/ Year
	Type	Class		
Well Pad and Access Road Construction Traffic	Semi Trucks	HDDV	4	80
	Pickup Trucks	LDDT	4	30
Pipeline Construction	Semi Trucks	HDDV	5	16
	Pickup Trucks	LDDT	5	18

Drilling/Completion/Fracing Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/activity/ Year
	Type	Class		
Drilling Traffic	Semi Trucks	HDDV	4	136
	Pickup Trucks	LDDT	5	136
Rig Hauling	Semi Trucks	HDDV	5	1
Rig Move Drilling Traffic	Semi Trucks	HDDV	5	90
	Pickup Trucks	LDDT	5	42
Well Completion & Testing	Semi Trucks	HDDV	5	84
	Pickup Trucks	LDDT	5	74

Ops_Well WO Workovers

Construction Equipment

Activity	Equipment Type	Capacity (hp)	# of Operating Hours/Day	# of Operating Days/Well	Load Factor	Well Workover Frequency per Year	NONROAD SCC
Well Workover	Workover Equipment	638	9	6	43	0.08	2270010010

Tier Level	HP Range for Efs	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Tier 2	600-750	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Traffic

Activity	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well/Year
	Type	Class		
Well Workover	WO Rig	HDDV	4	4
	Haul Truck	HDDV	4	12
	Pickup Truck	LDDT	4	20

blowdown		Blowdown Venting	
Type	Control Efficiency (%)	Volume of gas vented per blowdown Uncontrolled (MCF)	Frequency of Blowdown per well per year
Blowdown	0%	0.75	3.0

Data updated from White River Air Quality Technical Support Document, URS, 2012

well completion		Completion Venting
Type	Total volume of gas during completion (mcf)	
All completions	1,000	

Data updated from White River Air Quality Technical Support Document, URS, 2012

Recompletion		Recompletion Venting	
Type	Control Efficiency (%)	Volume of gas vented per well per recompletion Uncontrolled (MCF)	No. of recompletion per well per year
Recompletion	0%	1000	1%

Data updated from White River Air Quality Technical Support Document, URS, 2012

Compressor_Venting		Compressor Venting		
Type	Control Efficiency (%)	Volume of gas vented per start-up or shutdown Uncontrolled (MCF)	Frequency of Start-up per well per year	Frequency of Shutdown per well per year
Compressor Shutdown	0%	10	1	1

Wellhead Fugitives		Wellhead Fugitive Devices, Pneumatic Devices, and Pneumatic Pumps		
Fugitive Devices				
component	Ave. # in Gas Service	Ave. # in Liquid service	Ave. # in High Oil service	Ave. # in Water/Oil Service
valves	49	14	0	3
pump seals	2	1	0	0
others	46	0	0	0
connectors	0	0	0	0
flanges	13	8	0	1
open-ended lines	6	2	0	0

Pneumatic Pumps

Type	Gallons/yr/pump	SCF/Gallon	Number of Pump
Pneumatic Pumps	91	118	1

Pneumatic Devices

Device	Number of Devices / well	Lo-Bleed Rate (cfh)
Liquid level controller	2	6
Pressure controller	1	6
Valve controllers	2.0	6
Liquid level controller	0.1	6

Data updated from Colorado River Valley Air Quality Technical Support Document, URS, 2012

WaterInjection_
Pumps_Exh Water Injection Pumps

Type	Capacity (hp)	# of Units per well	Avg. Load Factor (%)	# of Operating Hours	Equipment Category	2011 Emission Factors (g/hp-hr)								
						VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Water Injection Pumps	347	0.06	47	2920	Pumps	0.13	0.59	2.14	0.10	0.10	0.00	227.95	0.00	0.00

Source: EPA NONROADS 2008a

^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Misc_Engines_Exh Miscellaneous Engines

Construction Site	Capacity (hp)	# of Units per Well	Fraction of wells to be served by Miscellaneous engine	Avg. Load Factor (%)	# of Operating Hours/Well	Equipment Category
Misc. Engines	118	1	1	50	4380	Misc. Engines

HP Range	2011 Emission Factors (g/hp-hr)								
	VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
175	0.12	0.41	1.59	0.10	0.10	0.00	227.98	0.00	0.00

Source: EPA NONROADS 2008a

^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Condensate Tanks & Traffic	Condensate Tanks
Type	Base Year Assumptions
Condensate	1. All Condensate Throughput Sent Tanks
	2. Average Condensate Truck Haulout of 200 bbl/load
Produced Water	3. All Water Throughput Sent Tanks
	4. Average Water Truck Haulout of 100 bbl/load
	5. Based on COGCC data from 2008 to 2011, assumed that about 16 times as much produced water from active wells relative to condensate

Uncontrolled VOC Emission Factors for Condensate Tanks

Applicable to Garfield, Mesa, Rio Blanco,
Moffat Counties*

10

lb/bbl

**The uncontrolled VOC emissions factor from Oil and Gas Exploration and Regulation Requirement Fact Sheet, Colorado Department of Public Health and Environment, Air Pollution Control Division, January, 2009.*

<http://www.cdphe.state.co.us/ap/sbap/SBAPoigastankguidance.pdf>

Flash Gas Weight Fractions

CO2 Fraction in Flash Gas	%wt	2
CH4 Fraction in Flash Gas	%wt	9
VOC Fraction in Flash Gas	%wt	58
VOC Molecular weight in Flash gas	lb/lb-mol	36

Condensate Truck Load-out

True vapor pressure of liquid loaded, pounds per square inch absolute (psia)	5.2
Mode of Operation	submerged loading: dedicated normal service

Produced Water and Condensate Truck Traffic

Construction Site Destination	Vehicle		Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/BBL OR Round Trips/Year/well
	Type	Class			
Produced Condensate Hauling	Haul Truck (200 bbl)	HDDV	15	4	0.005
Water Hauling	Haul Truck (130 bbl)	HDDV	35	20	70.19

Based on 50% of the water production being hauled. BLM Coalbed Methane Emissions Calculator. Received from BLM March 2012

Ops_RoadMaint Maintenance Traffic

Activity	Vehicle		Total Miles Traveled Per Well	Avg. Vehicle Speed (mph)
	Type	Class		
Road Maintenance	Pickup Truck	LDDV	18	15

Compressor_Engines

Compressor Engines

Type of Compressors / Pumps	Rate (Hp)	# Units per Well	Annual Compression (Hp)	Operating Hours/Year
Wellhead Compressor Engines	45	0.1	4	6,778
Lateral Compressor Engines	212	0.02	5	8,760

comp_main_
Traffic

Compressor Station Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Compressor Station
Compressor Maintenance	Pickup Truck	13	855

Reclaim-
RdsWells

Well Pad Reclamation

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Well
Road and Well Pad Reclamation	Pickup Truck	13	1,110

Others Traffic

Other Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/Year/well
Fuel Hauling	HDDV	15	7	0.6

Heaters and Flaring

Heaters

Wellsite Heaters	Heater Rating (MMBtu/hr)	Fraction of the year heating	hr/yr	No.of Units per Well
Heaters	0.83	0.57	4964	1
Reboilers	0.67	0.53	4599	1

Ops Dehy		Dehydrators	
Uncontrolled VOC Emissions (tons/mscf)	Uncontrolled CH4 Emissions (tons/mscf)	Uncontrolled CO2 Emissions (tons/mscf)	
2.51E-06	4.03E-06	3.15E-07	
Data updated from White River Air Quality Technical Support Document, URS, 2012			

APPENDIX C-2

Shale Gas Well Calculator Inputs by Source Category

Note: Yellow highlights indicate that inputs were obtained from the Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012. All inputs except those from the Bull Mountain Emission Inventory are noted.

Green highlights indicate that inputs were obtained from the data from Bull Mountain Emission Inventory Aug, 2013

Gas Analysis & Venting		Speciated Sales Gas Analysis	
Gas Component		Mole Fraction	
		(%)	
	Methane C1		90.150
	Ethane C2		1.960
	Nitrogen		0.160
	Water		0.000
	Carbon Dioxide		6.660
	Nitrous Oxide		0.000
	Hydrogen Sulfide		0.000
	Propane C3		0.520
	i-Butane i-C4		0.120
	n-Butane n-C4		0.100
	i-Pentane iC5		0.060
	n-Pentane nC5		0.030
	Hexanes+ C6+		0.128
	Heptanes C7		0.000
	Octanes+		0.000
	Benzene		0.036
	Ethylbenzene		0.002
	n-Hexane n-C6		0.000
	Toluene		0.047
	2,2,4-Trimethylpentane		0.000
	Xylenes		0.017
	Helium		0.010
	O2		0.000

*The full gas composition did not include BTEX and n-hexane components. These were included by adding separately provided BTEX and n-hexane mole fractions to the composition above and subtracting the corresponding mole fractions from the hexanes+ component.

Cn_HEq_Exh Construction/Drilling/Completion Equipment

Construction Equipment

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/Well Pad**	HP Range
Well Pad	Haul Truck	250	3	40	8	13	300
	Trackhoe	250	1	40	8	13	300
	Dozer	250	2	40	8	13	300
	Grader	250	1	40	8	13	300
	Compactor	250	1	40	8	13	300
	Water Truck	250	1	40	8	13	300
Well Pad Access Road	Dozer	250	2	40	8	10	300
	Grader	250	1	40	8	10	300
	Trackhoe	250	1	40	8	10	300
	Haul Truck	250	3	40	8	10	300
Pipeline	Dozer	250	1	40	10	10	300
	Grader	250	1	40	10	10	300
	Trackhoe	250	1	40	10	10	300
	Bending Mach	250	1	40	10	10	300
	Sideboom	250	1	40	10	10	300
	Utility Tractor	250	1	40	10	10	300

**Includes pad reclamation associated activity

Construction Site	Equipment Type	2011 Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Well Pad	For all Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Well Pad Access Road	For all Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Pipeline	For all Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Source: EPA NONROADS 2008a										
^a N2O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.										

Drilling

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range for Efs
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	1200	1	40	24	35	2270010010	Tier 2	>1200

Construction Site	Equipment Type	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N2O
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002
Source: EPA Federal Tier Standards										
aN2O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.										

Completion/Fracing

Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range
Completion Equipment	1230	1	40	7	1	2270010010	Tier 2	>1200
Fracing Equipment	12000	1	85	24	1	2270010010	Tier 2	>1200
Refracing Equipment	1500	4	97	1	3	2270010010	Tier 2	>1200

Grand Junction Field Office Air Quality Technical Support Document, ENVIRON, 2012

Data updated from White River Air Quality Technical Support Document, URS, 2012 (Fracing Equipment), and from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012 (Completion)

Equipment Type	Capacity (hp)	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Completion Equipment	1230	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Fracing Equipment	12000	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Refracing Equipment	1500	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Source: EPA Federal Tier Standards										
^a N ₂ O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.										

Fracing frequency per spud	1
Refracing Frequency per Year per Well	0.25

Cn_CV_Exh Construction Traffic Exhaust

Well Pad and Access Road Construction Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well Pad/ Year
	Type	Class		
Well Pad and Access Road Construction Traffic	Semi Trucks	HDDV	16	164
	Pickup Trucks	LDDT	16	40
Pipeline Construction	Semi Trucks	HDDV	16	35
	Pickup Trucks	LDDT	16	48

Drilling/Completion/Fracing Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/activity/Year
	Type	Class		
Drilling Traffic	Semi Trucks	HDDV	16	917
	Pickup Trucks	LDDT	16	274
Rig Hauling	Semi Trucks	HDDV	16	1
Rig Move Drilling Traffic	Semi Trucks	HDDV	16	90
	Pickup Trucks	LDDT	16	42
Well Completion & Testing	Semi Trucks	HDDV	16	84
	Pickup Trucks	LDDT	16	74

Cn_HEq_FDust

Construction Traffic Dust

Area Disturbed for Oil Wells	Avg. Disturbed Acres per wellpad	Construction Days
Well Pad	3.75	15
Well Pad Access Road and Pipeline Construction	1.8	8

Road and Pipeline Construction, (Pipeline Percentage of Acreage)

6%

Ops_Well WO

Workovers

Construction Equipment

Activity	Equipment Type	Capacity (hp)	# of Operating Hours/Day	# of Operating Days/Well	Load Factor	Well Workover Frequency per Year	NONROAD SCC
Well Workover	Workover Equipment	500	10	7	43	0.5	2270010010

Tier Level	HP Range for Efs	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Tier 2	600-750	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Traffic

Activity	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well/Year
	Type	Class		
Well Workover	WO Rig	HDDV	4.1	0.6
	Haul Truck	HDDV	4.1	1.3
	Pickup Truck	LDDT	4.1	6.4

blowdown				Blowdown Venting			
Type		Control Efficiency (%)		Volume of gas vented per blowdown Uncontrolled (MCF)		Frequency of Blowdown per well per year	
Blowdown		0%		0.81		3.4	

Data updated from White River Air Quality Technical Support Document, URS, 2012

well completion		Completion Venting
Type	Total volume of gas during completion (mcf)	
All completions	1,000	

Recompletion		Recompletion Venting	
Type	Control Efficiency (%)	Volume of gas vented per well per recompletion Uncontrolled (MCF)	No. of recompletion per well per year
Recompletion	0%	30	50%

Compressor_Venting		Compressor Venting		
Type	Control Efficiency (%)	Volume of gas vented per start-up or shutdown Uncontrolled (MCF)	Frequency of Start-up per well per year	Frequency of Shutdown per well per year
Compressor Shutdown	0%	10	1	1

Wellhead Fugitives		Wellhead Fugitive Devices, Pneumatic Devices, and Pneumatic Pumps		
Fugitive Devices				
component	Ave. # in Gas Service	Ave. # in Liquid service	Ave. # in High Oil service	Ave. # in Water/Oil Service
valves	49	14	0	3
pump seals	2	1	0	0
others	46	0	0	0
connectors	0	0	0	0
flanges	13	8	0	1
open-ended lines	6	2	0	0

Pneumatic Pumps

Type	Gallons/yr/pump	SCF/Gallon	Number of Pump
Pneumatic Pumps	91	118	1

Pneumatic Devices

Device	Number of Devices / well	Lo-Bleed Rate (cfh)
Liquid level controller	2	6
Pressure controller	1	6
Valve controllers	2.0	6
Liquid level controller	0.1	6

Data updated from Colorado River Valley Air Quality Technical Support Document, URS, 2012

WaterInjection_
Pumps_Exh Water Injection Pumps

Type	Capacity (hp)	# of Units per well	Avg. Load Factor (%)	# of Operating Hours	Equipment Category	2011 Emission Factors (g/hp-hr)								
						VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Water Injection Pumps	347	0.09	47	2920	Pumps	0.13	0.59	2.14	0.10	0.10	0.00	227.95	0.00	0.00

Source: EPA NONROADS 2008a

^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Miscellaneous Engines						
Misc. Engines_Exh						
Construction Site	Capacity (hp)	# of Units per Well	Fraction of wells to be served by Miscellaneous engine	Avg. Load Factor (%)	# of Operating Hours/Well	Equipment Category
Misc. Engines (wellsite water pumps)	19	1	1	47%	8760	Misc. Engines

HP Range	2011 Emission Factors (g/hp-hr)							
	VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	N ₂ O ^a
25	0.27	1.68	8.16	0.04	0.04	0.00	557.28	0.01

Source: Emission factors for NO_x and VOC from EPA Nonroad Spark-Ignition Engines 19 kW and Below - Exhaust Emission Standards, Phase 2, Class II Engine. Emission factors for CO, PM₁₀ and PM_{2.5} and HAPs from AP-42, Volume I, Fifth Edition, Table 3.2-1.

Emission factors for CO₂, CH₄, and N₂O from Tables C-1 and C-2 of 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule.

Condensate Tanks & Traffic	Condensate Tanks
Type	Base Year Assumptions
Condensate	1. All Condensate Throughput Sent Tanks
	2. Average Condensate Truck Haulout of 200 bbl/load
Produced Water	3. All Water Throughput Sent Tanks
	4. Average Water Truck Haulout of 100 bbl/load
	5. Based on COGCC data from 2008 to 2011, assumed that about 16 times as much produced water from active wells relative to condensate

Uncontrolled VOC Emission Factors for Condensate Tanks

Applicable to Garfield, Mesa, Rio Blanco,
Moffat Counties*

10

lb/bbl

**The uncontrolled VOC emissions factor from Oil and Gas Exploration and Regulation Requirement Fact Sheet, Colorado Department of Public Health and Environment, Air Pollution Control Division, January, 2009.*

<http://www.cdphe.state.co.us/ap/sbap/SBAPoilagastankguidance.pdf>

Flash Gas Weight Fractions

CO2 Fraction in Flash Gas	%wt	2
CH4 Fraction in Flash Gas	%wt	9
VOC Fraction in Flash Gas	%wt	58
VOC Molecular weight in Flash gas	lb/lb-mol	36

Condensate Truck Load-out

True vapor pressure of liquid loaded, pounds per square inch absolute (psia)	5.2
Mode of Operation	submerged loading: dedicated normal service

Produced Water and Condensate Truck Traffic

Construction Site Destination	Vehicle		Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/BBL OR Round Trips/Year/well
	Type	Class			
Produced Condensate Hauling	Haul Truck (200 bbl)	HDDV	15	4	0.005
Water Hauling	Haul Truck (130 bbl)	HDDV	15	4	70.19

Based on 50% of the water production being hauled. BLM Coalbed Methane Emissions Calculator. Received from BLM March 2012

Ops_RoadMaint Maintenance Traffic

Activity	Vehicle		Total Miles Traveled Per Well	Avg. Vehicle Speed (mph)
	Type	Class		
Road Maintenance	Pickup Truck	LDDV	18	15

Compressor_Engines

Compressor Engines

Type of Compressors / Pumps	Rate (Hp)	# Units per Well	Annual Compression (Hp)	Operating Hours/Year
Wellhead Compressor Engines	45	0.1	4	6,778
Lateral Compressor Engines	212	0.02	5	8,760

comp_main_
Traffic

Compressor Station Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Compressor Station
Compressor Maintenance	Pickup Truck	13	107

Reclaim-
RdsWells

Well Pad Reclamation

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Well
Road and Well Pad Reclamation	Pickup Truck	15	416

Others Traffic

Other Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/Year/well
Fuel Hauling	HDDV	15	7	7

Heaters and Flaring

Heaters

Wellsite Heaters	Heater Rating (MMBtu/hr)	Fraction of the year heating	hr/yr	No.of Units per Well
Heaters	0.23	0.17	1460	3
Reboilers	0.25	0.50	4380	1

The Bull Mountain Emission Inventory estimated emissions from one separator heater with 0.125 mmbtu/hr heater rating, 4380 hours /year and 4 tank heaters with 0.25 mmbtu/hr heater rating and 730 hours/year. For this project, weighted average of separator heater and tank heaters data were used to estimate heater emissions.

Ops Dehy

Dehydrators

Uncontrolled VOC Emissions (tons/mscf)	Uncontrolled CH4 Emissions (tons/mscf)	Uncontrolled CO2 Emissions (tons/mscf)
1.72E-06	2.24E-06	2.91E-06

APPENDIX C-3

Coalbed Natural Gas Well Calculator Inputs by Source Category

Note: Yellow highlights indicate that inputs were obtained from the BLM Coalbed Methane Emissions Calculator. Received from BLM March 2012. All inputs taken from other sources are noted.

Gas Analysis & Venting		Speciated Sales Gas Analysis	
Gas Component		Mole Fraction	
		(%)	
Methane C1		97.913	
Ethane C2		0.000	
Nitrogen		1.173	
Water		0.000	
Carbon Dioxide		0.851	
Nitrous Oxide		0.000	
Hydrogen Sulfide		0.000	
Propane C3		0.063	
i-Butane i-C4		0.000	
n-Butane n-C4		0.000	
i-Pentane iC5		0.000	
n-Pentane nC5		0.000	
Hexanes C6		0.000	
Heptanes C7		0.000	
Octanes+		0.000	
Benzene		0.000	
Ethylbenzene		0.000	
n-Hexane n-C6		0.000	
Toluene		0.000	
2,2,4-Trimethylpentane		0.000	
Xylenes		0.000	

Cn_HEq_Exh Construction/Drilling/Completion Equipment

Construction Equipment

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/Well Pad	Equipment Category	HP Range
Well Pad	Construction Equipment	200	2	80	12	3	Other Construction Equipment	300
Well Pad Access Road	Construction Equipment	200	1	80	4	1	Other Construction Equipment	300
Pipeline	Construction Equipment	200	2	80	10	2	Other Construction Equipment	300

Construction Site	Equipment Type	2011 Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Well Pad	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Well Pad Access Road	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Pipeline	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00

Source: EPA NONROADS 2008a
^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Drilling

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range for Efs
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	400	3	77	24	3	2270010010	Tier 2	300-600

Construction Site	Equipment Type	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Source: EPA Federal Tier Standards
^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Completion/Fracing

Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range
Completion Equipment	400	1	50	10	5	2270010010	Tier 2	300-600
Fracing Equipment	-	-	-	-	-	-	-	-
Refracing Equipment	-	-	-	-	-	-	-	-

Equipment Type	Capacity (hp)	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Completion Equipment	400	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Fracing Equipment	-	-	-	-	-	-	-	-	-	-
Refracing Equipment	-	-	-	-	-	-	-	-	-	-
Source: EPA Federal Tier Standards										
^a N ₂ O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.										

Fracing frequency per spud	-
Refracing Frequency per Year per Well	-

Cn_CV_Exh Construction Traffic Exhaust

Well Pad and Access Road Construction Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well Pad/ Year
	Type	Class		
Well Pad and Access Road Construction Traffic	Semi Trucks	HDDV	20	3
	Pickup Trucks	LDDT	20	3
Pipeline Construction	Semi Trucks	HDDV	20	8
	Pickup Trucks	LDDT	20	8

Drilling/Completion/Fracing Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/activity/ Year
	Type	Class		
Drilling Traffic	Semi Trucks	HDDV	20	2
	Pickup Trucks	LDDT	20	20
Rig Hauling	Semi Trucks	HDDV	20	12
Rig Move Drilling Traffic	Semi Trucks	HDDV	20	1
	Pickup Trucks	LDDT	20	16
Well Completion & Testing	Semi Trucks	HDDV	20	36
	Pickup Trucks	LDDT	20	12

Cn_HEq_FDust Construction Traffic Dust

Area Disturbed for Oil Wells	Avg. Disturbed Acres per wellpad	Construction Days
Well Pad	6.00	2.50
Well Pad Access Road and Pipeline Construction	4.9	2.17

Road and Pipeline Construction, (Pipeline Percentage of Acreage)	6%
------------------------------------------------------------------	----

Data from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012

Ops_Well WO Workovers

Construction Equipment

Activity	Equipment Type	Capacity (hp)	# of Operating Hours/Day	# of Operating Days/Well	Load Factor	Well Workover Frequency per Year	NONROAD SCC
Well Workover	Workover Equipment	400	10	2	43	0.08	2270010010

Data from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012

Tier Level	HP Range for Efs	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Tier 2	600-750	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Traffic

Activity	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well/Year
	Type	Class		
Well Workover	WO Rig	HDDV	20	1
	Haul Truck	HDDV	20	1
	Pickup Truck	LDDT	20	2

blowdown Blowdown Venting

Type	Control Efficiency (%)	Volume of gas vented per blowdown Uncontrolled (MCF)	Frequency of Blowdown per well per year
Blowdown	0%	200	2.0

Data updated from White River Air Quality Technical Support Document, URS, 2012

well completion Completion Venting

Type	Total volume of gas during completion (mcf)
All completions	1,000

Data updated from White River Air Quality Technical Support Document, URS, 2012

Recompletion		Recompletion Venting	
Type	Control Efficiency (%)	Volume of gas vented per well per recompletion Uncontrolled (MCF)	No. of recompletion per well per year
Recompletion	0%	1000	1%

Data updated from White River Air Quality Technical Support Document, URS, 2012

Compressor_Venting		Compressor Venting		
Type	Control Efficiency (%)	Volume of gas vented per start-up or shutdown Uncontrolled (MCF)	Frequency of Start-up per well per year	Frequency of Shutdown per well per year
Compressor Shutdown	0%	10	1	1

Data from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012

Wellhead Fugitives		Wellhead Fugitive Devices, Pneumatic Devices, and Pneumatic Pumps		
Fugitive Devices				
component	Ave. # in Gas Service	Ave. # in Liquid service	Ave. # in High Oil service	Ave. # in Water/Oil Service
valves	49	14	0	3
pump seals	2	1	0	0
others	46	0	0	0
connectors	0	0	0	0
flanges	13	8	0	1
open-ended lines	6	2	0	0

Pneumatic Pumps

Type	Gallons/yr/pump	SCF/Gallon	Number of Pump
Pneumatic Pumps	-	-	-

Pneumatic Devices

Device	Number of Devices / well	Lo-Bleed Rate (cfh)
Liquid level controller	5	6
Transducer	5	6

 WaterInjection_
Pumps_Exh Water Injection Pumps

Type	Capacity (hp)	# of Units per well	Avg. Load Factor (%)	# of Operating Hours	Equipment Category	2011 Emission Factors (g/hp-hr)								
						NOxa	PM10b	SO2b	COa	VOCa	PM2.5b	CO2c	CH4c	N2Oc
Water Injection Pumps	34	1	47	8760	Pumps	2.14	0.10	0.0045	0.59	0.13	0.10	227.95	0.002	0.002

a Source: assume compressors will comply with NSPS 40 CFR part 60 subpart JJJJ (same rates as Colorado Regulation 7)

b Source: EPA, AP-42 Section 3.2 Natural Gas Fired Reciprocating Engines

c EPA Mandatory GHG Reporting, Part 98, Subpart C, Tables C-1 and C-2.

Condensate Tanks & Traffic	Condensate Tanks
Type	Base Year Assumptions
Condensate	1. All Condensate Throughput Sent Tanks
	2. Average Condensate Truck Haulout of 200 bbl/load
Produced Water	3. All Water Throughput Sent Tanks
	4. Average Water Truck Haulout of 100 bbl/load
	5. Based on COGCC data from 2008 to 2011, assumed that about 16 times as much produced water from active wells relative to condensate

Uncontrolled VOC Emission Factors for Condensate Tanks

Applicable to Garfield, Mesa, Rio Blanco,
Moffat Counties*

10

lb/bbl

**The uncontrolled VOC emissions factor from Oil and Gas Exploration and Regulation Requirement Fact Sheet, Colorado Department of Public Health and Environment, Air Pollution Control Division, January, 2009.*

<http://www.cdphe.state.co.us/ap/sbap/SBAPoiltankguidance.pdf>

Flash Gas Weight Fractions

CO2 Fraction in Flash Gas	%wt	2
CH4 Fraction in Flash Gas	%wt	9
VOC Fraction in Flash Gas	%wt	58
VOC Molecular weight in Flash gas	lb/lb-mol	36

Condensate Truck Load-out

True vapor pressure of liquid loaded, pounds per square inch absolute (psia)	5.2
Mode of Operation	submerged loading: dedicated normal service

Produced Water and Condensate Truck Traffic

Construction Site Destination	Vehicle		Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/BBL OR Round Trips/Year/well
	Type	Class			
Produced Condensate Hauling	Haul Truck (200 bbl)	HDDV	30	20	0.0
Water Hauling	Haul Truck (130 bbl)	HDDV	35	20	70

Assumed 50% of the water production is hauled.

Ops_RoadMaint Maintenance Traffic

Activity	Vehicle		Total Miles Traveled Per Well	Avg. Vehicle Speed (mph)
	Type	Class		
Road Maintenance	Pickup Truck	LDDV	1	15

comp_main_
Traffic Compressor Station Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Compressor Station
Compressor Maintenance	Pickup Truck	35	2,920

Reclaim-
RdsWells Well Pad Reclamation

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Well
Road and Well Pad Reclamation	Pickup Truck	30	28

Others Traffic Other Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/Year/well
Fuel Hauling	HDDV	15	14	1.0

Heaters and Flaring

Heaters

Wellsite Heaters	Heater Rating (MMBtu/hr)	Fraction of the year heating	hr/yr	No.of Units per Well
Heaters	0.50	0.30	8760	1
Reboilers	3.00	0.30	8760	0.002

Data from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012

Ops Dehy

Dehydrators

Uncontrolled VOC Emissions (tons/mscf)	Uncontrolled CH4 Emissions (tons/mscf)	Uncontrolled CO2 Emissions (tons/mscf)
1.26E-07	1.60E-05	0.00E+00

APPENDIX C-4

Conventional Oil Well Calculator Inputs by Source Category

Note: Yellow highlights indicate that inputs were obtained from the Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012. All inputs taken from other sources are noted.

Gas Analysis & Venting		Speciated Sales Gas Analysis	
Gas Component		Mole Fraction	
		(%)	
Methane C1		81.012	
Ethane C2		4.334	
Nitrogen		6.718	
Water		0.000	
Carbon Dioxide		5.380	
Nitrous Oxide		0.000	
Hydrogen Sulfide		0.000	
Propane C3		1.437	
i-Butane i-C4		0.288	
n-Butane n-C4		0.329	
i-Pentane iC5		0.154	
n-Pentane nC5		0.104	
Hexanes C6		0.111	
Heptanes C7		0.037	
Octanes+		0.017	
Benzene		0.004	
Ethylbenzene		0.000	
n-Hexane n-C6		0.068	
Toluene		0.003	
2,2,4-Trimethylpentane		0.001	
Xylenes		0.002	

Cn_HEq_Exh Construction/Drilling/Completion Equipment

Construction Equipment

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/Well Pad	Equipment Category	HP Range
Well Pad	Construction Equipment	250	4	42	10	13	Other Construction Equipment	300
Well Pad Access Road	Construction Equipment	250	4	42	10	10	Other Construction Equipment	300
Pipeline	Construction Equipment	250	2	42	10	2	Other Construction Equipment	300

Construction Site	Equipment Type	2011 Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Well Pad	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Well Pad Access Road	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00
Pipeline	Construction Equipment	0.18	0.78	2.32	0.15	0.15	0.01	316.19	0.00	0.00

Source: EPA NONROADS 2008a
 ^aN2O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Drilling

Construction Site	Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range for Efs
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	2469	2	40	24	17	2270010010	Tier 2	>1200

Construction Site	Equipment Type	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N2O ^a
Rig-up, Drilling, and Rig-down	Drilling Equipment - Avg	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Source: EPA Federal Tier Standards
^aN2O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Completion/Fracing

Equipment Type	Capacity (hp)	# of Units	Avg. Load Factor (%)	# of Operating Hours/Day	# of Operating Days/activity	NONROAD SCC	Tier Level	HP Range
Completion Equipment	1230	1	40	7	1	2270010010	Tier 2	>1200
Fracing Equipment	12000	1	85	24	1	2270010010	Tier 2	>1200
Refracing Equipment	1500	4	97	1	3	2270010010	Tier 2	>1200

Grand Junction Field Office Air Quality Technical Support Document, ENVIRON, 2012

Data updated from White River Air Quality Technical Support Document, URS, 2012 (Fracing Equipment), and from Uncompahgre Field Office Air Quality Technical Support Document, ENVIRON, 2012 (Completion)

Equipment Type	Capacity (hp)	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Completion Equipment	1230	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Fracing Equipment	12000	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002
Refracing Equipment	1500	0.26	2.61	4.53	0.15	0.15	0.11	523	0.004	0.002

Source: EPA Federal Tier Standards
^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Fracing frequency per spud	1
Refracing Frequency per Year per Well	0.05

Cn_CV_Exh Construction Traffic Exhaust

Well Pad and Access Road Construction Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well Pad/ Year
	Type	Class		
Well Pad and Access Road Construction Traffic	Semi Trucks	HDDV	4	80
	Pickup Trucks	LDDT	4	30
Pipeline Construction	Semi Trucks	HDDV	5	16
	Pickup Trucks	LDDT	5	18

Drilling/Completion/Fracing Traffic

Construction Site Destination	Vehicle		Round Trip Distance (miles)	# of Round Trips/activity/ Year
	Type	Class		
Drilling Traffic	Semi Trucks	HDDV	4	136
	Pickup Trucks	LDDT	5	136
Rig Hauling	Semi Trucks	HDDV	5	1
Rig Move Drilling Traffic	Semi Trucks	HDDV	5	90
	Pickup Trucks	LDDT	5	42
Well Completion & Testing	Semi Trucks	HDDV	5	84
	Pickup Trucks	LDDT	5	74

Cn_HEq_FDust Construction Traffic Dust

Area Disturbed for Oil Wells	Avg. Disturbed Acres per wellpad	Construction Days
Well Pad	4.88	13
Well Pad Access Road and Pipeline Construction	9	10

Road and Pipeline Construction, (Pipeline Percentage of Acreage)	6%
------------------------------------------------------------------	----

Ops_Well WO Workovers

Construction Equipment

Activity	Equipment Type	Capacity (hp)	# of Operating Hours/Day	# of Operating Days/Well	Load Factor	Well Workover Frequency per Year	NONROAD SCC
Well Workover	Workover Equipment	638	9	6	43	0.08	2270010010

Tier Level	HP Range for Efs	Tier Emission Factors (g/hp-hr)								
		VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Tier 2	600-750	0.26	2.61	4.53	0.15	0.15	0.11	530	0.004	0.002

Traffic

Activity	Vehicle		Round Trip Distance (miles)	# of Round Trips/Well/Year
	Type	Class		
Well Workover	WO Rig	HDDV	4	4
	Haul Truck	HDDV	4	12
	Pickup Truck	LDDT	4	20

blowdown

Blowdown Venting

Type	Control Efficiency (%)	Volume of gas vented per blowdown Uncontrolled (MCF)	Frequency of Blowdown per well per year
Blowdown	0%	0.75	3.0

Data updated from White River Air Quality Technical Support Document, URS, 2012

well completion

Completion Venting

Type	Total volume of gas during completion (mcf)
All completions	1,000

Data updated from White River Air Quality Technical Support Document, URS, 2012

Recompletion		Recompletion Venting	
Type	Control Efficiency (%)	Volume of gas vented per well per recompletion Uncontrolled (MCF)	No. of recompletion per well per year
Recompletion	0%	1000	1%

Data updated from White River Air Quality Technical Support Document, URS, 2012

Compressor_Venting		Compressor Venting		
Type	Control Efficiency (%)	Volume of gas vented per start-up or shutdown Uncontrolled (MCF)	Frequency of Start-up per well per year	Frequency of Shutdown per well per year
Compressor Shutdown	0%	10	1	1

Wellhead Fugitives		Wellhead Fugitive Devices, Pneumatic Devices, and Pneumatic Pumps		
Fugitive Devices				
component	Ave. # in Gas Service	Ave. # in Liquid service	Ave. # in High Oil service	Ave. # in Water/Oil Service
valves	49	14	0	3
pump seals	2	1	0	0
others	46	0	0	0
connectors	0	0	0	0
flanges	13	8	0	1
open-ended lines	6	2	0	0

Pneumatic Pumps

Type	Gallons/yr/pump	SCF/Gallon	Number of Pump
Pneumatic Pumps	91	118	1

Pneumatic Devices

Device	Number of Devices / well	Lo-Bleed Rate (cfh)
Liquid level controller	2	6
Pressure controller	1	6

Valve controllers	2.0	6
Liquid level controller	0.1	6

Data updated from Colorado River Valley Air Quality Technical Support Document, URS, 2012

WaterInjection_ Pumps_Exh Water Injection Pumps

Type	Capacity (hp)	# of Units per well	Avg. Load Factor (%)	# of Operating Hours	Equipment Category	2011 Emission Factors (g/hp-hr)								
						VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
Water Injection Pumps	347	0.06	47	2920	Pumps	0.13	0.59	2.14	0.10	0.10	0.00	227.95	0.00	0.00

Source: EPA NONROADS 2008a

^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Misc_Engines_Exh Miscellaneous Engines

Construction Site	Capacity (hp)	# of Units per Well	Fraction of wells to be served by Miscellaneous engine	Avg. Load Factor (%)	# of Operating Hours/Well	Equipment Category
Misc. Engines	118	1	1	50	4380	Misc. Engines

HP Range	2011 Emission Factors (g/hp-hr)								
	VOC	CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	CO ₂	CH ₄	N ₂ O ^a
175	0.12	0.41	1.59	0.10	0.10	0.00	227.98	0.00	0.00

Source: EPA NONROADS 2008a

^aN₂O factor source: 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17. 130,500 Btu/gallon, 2545 Btu/hp-hr.

Condensate Tanks & Traffic	Condensate Tanks
Type	Base Year Assumptions
Condensate	1. All Condensate Throughput Sent Tanks
	2. Average Condensate Truck Haulout of 200 bbl/load
Produced Water	3. All Water Throughput Sent Tanks
	4. Average Water Truck Haulout of 100 bbl/load
	5. Based on COGCC data from 2008 to 2011, assumed that about 16 times as much produced water from active wells relative to condensate

Uncontrolled VOC Emission Factors for Condensate Tanks

Applicable to Garfield, Mesa, Rio Blanco,
Moffat Counties*

1.6

lb/bbl

*The uncontrolled VOC emissions factor from the BLM crude oil emission calculator

Flash Gas Weight Fractions

CO2 Fraction in Flash Gas	%wt	2
CH4 Fraction in Flash Gas	%wt	9
VOC Fraction in Flash Gas	%wt	58
VOC Molecular weight in Flash gas	lb/lb-mol	36

Condensate Truck Load-out

True vapor pressure of liquid loaded, pounds per square inch absolute (psia)	5.2
Mode of Operation	submerged loading: dedicated normal service

Produced Water and Condensate Truck Traffic

Construction Site Destination	Vehicle		Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/BBL OR Round Trips/Year/well
	Type	Class			

Produced Condensate Hauling	Haul Truck (200 bbl)	HDDV	15	4	0.005
Water Hauling	Haul Truck (130 bbl)	HDDV	35	20	70.19

Based on 50% of the water production being hauled. BLM Coalbed Methane Emissions Calculator. Received from BLM March 2012

Ops_RoadMaint Maintenance Traffic

Activity	Vehicle		Total Miles Traveled Per Well	Avg. Vehicle Speed (mph)
	Type	Class		
Road Maintenance	Pickup Truck	LDDV	18	15

Compressor_Engines Compressor Engines

Type of Compressors / Pumps	Rate (Hp)	# Units per Well	Annual Compression (Hp)	Operating Hours/Year
Wellhead Compressor Engines	45	0.1	4	6,778
Lateral Compressor Engines	212	0.02	5	8,760

comp_main_ Traffic Compressor Station Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Compressor Station
Compressor Maintenance	Pickup Truck	13	855

Reclaim-
RdsWells

Well Pad Reclamation

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Total Miles Traveled per Well
Road and Well Pad Reclamation	Pickup Truck	13	1,110

Others Traffic

Other Traffic

Activity	Vehicle Type	Avg. Vehicle Speed (mph)	Round Trip Distance (miles)	# of Round Trips/Year/well
Fuel Hauling	HDDV	15	7	0.6

Heaters and Flaring

Heaters

Wellsite Heaters	Heater Rating (MMBtu/hr)	Fraction of the year heating	hr/yr	No.of Units per Well
Heaters	0.83	0.57	4964	1
Reboilers	0.67	0.53	4599	1

Ops Dehy

Dehydrators

Uncontrolled VOC Emissions (tons/mscf)	Uncontrolled CH4 Emissions (tons/mscf)	Uncontrolled CO2 Emissions (tons/mscf)
2.51E-06	4.03E-06	3.15E-07

Data updated from White River Air Quality Technical Support Document, URS, 2012

APPENDIX C-5

Midstream Emissions by Field Office and Facility

Field Office	County	Facility Name	2011 Emissions (tons/year)					
			NOx	VOC	CO	PM10	PM2.5	SO2
Grand Junction	Garfield	BARGATH LLC - CRAWFORD TRAIL	208.02	71.50	80.14	6.262	6.262	0.430
Grand Junction	Garfield	CHEVRON USA INC - PICEANCE BASIN CENTRAL	91.80	58.22	52.00	1.938	1.938	0.174
Grand Junction	Garfield	ENCANA (WEST) - HAY CANYON	0.00	23.74	0.00	0.000	0.000	0.000
Grand Junction	Garfield	NATIONAL FUEL CORP. - BAXTER FACILITY	18.50	2.90	4.40	0.081	0.081	0.005
Grand Junction	Garfield	OXY USA WTP LP - CONN CREEK GAS	132.80	35.28	19.13	0.010	0.010	1.760
Grand Junction	Garfield	PUBLIC SERVICE CO BAXTER STATION	58.04	7.56	67.23	0.230	0.230	0.028
Grand Junction	Garfield	SOURCEGAS DBA ROCKY MTN -DEBEQUE C S	28.48	7.97	65.49	0.591	0.591	0.013
Grand Junction	Garfield	TRANSCOLORADO GAS - CONN CREEK	2.10	0.32	0.28	0.040	0.040	0.000
Grand Junction	Garfield	WPX ENERGY RKY MTN, LLC - TRAIL RIDGE CS	31.70	8.00	5.85	0.073	0.073	0.004
Grand Junction	Mesa	ASPEN OPERATING, LLC - SINK CREEK C.S.	49.15	2.81	2.72	0.052	0.000	0.003
Grand Junction	Mesa	AXIA ENERGY - TAYLOR COMPRESSOR STATION	32.75	54.32	72.48	0.000	0.000	0.000
Grand Junction	Mesa	BADGER MIDSTREAM SERVICES - BADGER WGP	50.02	31.39	54.43	1.074	1.074	0.075
Grand Junction	Mesa	BLACK HILLS MIDSTREAM - HORSESHOE CANYON	35.30	66.14	26.50	0.570	0.570	0.035
Grand Junction	Mesa	COLLBRAN VALLEY GAS - ANDERSON GULCH	127.63	68.11	60.97	4.369	4.366	0.120
Grand Junction	Mesa	COLLBRAN VALLEY GAS GATHERING- CVG #2	192.66	112.89	49.33	0.000	0.000	0.000
Grand Junction	Mesa	COLORADO FUEL MANUFACTURERS, INC.	33.20	87.51	21.75	0.975	0.975	1.077
Grand Junction	Mesa	DELTA PETROLEUM CORP - MVS CS AND HCPWRF	4.70	61.90	22.10	0.000	0.000	0.000
Grand Junction	Mesa	ENCANA - PLATEAU CREEK	19.74	11.24	12.78	0.800	0.800	0.008
Grand Junction	Mesa	ETC CANYON PIPELINE - BAR X C.S.	12.20	20.48	14.20	0.376	0.376	0.023
Grand Junction	Mesa	ETC CANYON PIPELINE - PREMIER BAR X	73.32	7.82	5.09	1.340	1.340	0.020
Grand Junction	Mesa	ETC CANYON PIPELINE -PREMIER DEBEQUE	76.04	43.37	55.85	0.998	0.998	0.060
Grand Junction	Mesa	FRAM OPERATING - REEDER MESA CS	74.46	48.70	100.70	0.011	0.011	0.081
Grand Junction	Mesa	NATL FUEL CORP	22.07	7.55	8.85	0.307	0.307	0.015
Grand Junction	Mesa	OXY USA - BRUSH CREEK COMPRESSOR	86.20	61.31	57.57	0.443	0.443	0.027

Field Office	County	Facility Name	2011 Emissions (tons/year)					
			NOx	VOC	CO	PM10	PM2.5	SO2
		STATION						
Grand Junction	Mesa	OXY USA INC. - East Plateau CS	77.67	32.42	48.93	1.772	1.772	0.106
Grand Junction	Mesa	PICEANCE ENERGY - BRUTON C.S.	12.13	11.03	17.19	0.640	0.640	0.000
Grand Junction	Mesa	PICEANCE ENERGY LLC - HAWXHURST RANCH	8.64	23.32	17.26	0.000	0.000	0.000
Grand Junction	Mesa	PUBLIC SERVICE CO ASBURY STATION	26.78	10.67	43.32	0.110	0.110	0.007
Grand Junction	Mesa	PUBLIC SERVICE CO HUNTER CANYON STA	16.37	0.62	1.99	0.200	0.200	0.003
Grand Junction	Mesa	SOURCEGAS DBA ROCKY MTN NG - COLLBRAN	22.82	12.50	19.72	0.460	0.260	0.010
Grand Junction	Mesa	TRANSCOLORADO GAS TR CO - WHITEWATER CS	12.37	5.73	4.65	0.360	0.360	0.020
Kremmling	Grand	PUBLIC SERVICE CO WILLIAMS FORK STATION	12.40	0.40	0.75	0.006	0.006	0.001
Little Snake	Moffat	AGAVE ENERGY - BIL HOL GULCH TREATING	8.58	32.79	17.16	0.040	0.040	0.000
Little Snake	Moffat	ARGALI EXPLORATION COMPANY	45.59	0.98	3.27	0.080	0.080	0.005
Little Snake	Moffat	CUSTOM ENERGY CONSTRUCTION INC BUCK PEAK	4.73	3.47	1.92	0.008	0.008	0.001
Little Snake	Moffat	J W OPERATING CO - GREAT DIVIDE C.S.	10.80	7.79	4.84	0.000	0.000	0.000
Little Snake	Moffat	J-W OPERATING COMPANY -SAND HILLS	28.40	13.25	2.10	0.000	0.000	0.000
Little Snake	Moffat	MERIT ENERGY - SANDWASH C.S.	19.34	7.96	12.90	0.000	0.000	0.000
Little Snake	Moffat	MERRION OIL & GAS - BLUE GRAVEL	34.41	0.11	35.37	0.070	0.070	0.000
Little Snake	Moffat	OVERLAND PASS - MIDPOINT STATION	0.00	8.60	0.00	0.000	0.000	0.000
Little Snake	Moffat	QEP FIELD SERVICES - EAST HIAWATHA CS	58.72	31.42	51.98	0.602	0.592	0.036
Little Snake	Moffat	QEP FIELD SERVICES - LION C.S.	14.30	7.63	14.30	0.475	0.475	0.029
Little Snake	Moffat	QEP FIELD SERVICES - W HIAWATHA C. S.	32.76	31.87	15.09	0.380	0.380	0.000
Little Snake	Moffat	QUESTAR - SKULL CREEK DEW POINT PLANT	56.46	87.10	41.61	0.364	0.359	0.022
Little Snake	Moffat	QUESTAR PIPELINE CO STATE LINE COMP STA	13.41	0.10	1.69	0.320	0.320	0.012
Little Snake	Moffat	QUESTAR PIPELINE PWFC SOUTHSIDE 2/MUSSER	38.54	2.15	1.91	0.070	0.070	0.004
Little Snake	Moffat	ROCKIES EXPRESS PIPELINE - BIG HOLE CS	12.60	4.01	9.96	0.690	0.690	1.290
Little Snake	Moffat	SAMSON RESOURCES - SHELL CREEK GAS COND	31.29	1.03	12.70	0.227	0.170	0.003

Field Office	County	Facility Name	2011 Emissions (tons/year)					
			NOx	VOC	CO	PM10	PM2.5	SO2
Little Snake	Moffat	WYOMING INTERSTATE - SNAKE RIVER C.S.	64.97	7.58	77.43	4.489	4.489	2.177
Little Snake	Rio Blanco	CHEVRON USA - WILSON CREEK GAS PLT	4.94	90.10	10.32	0.008	0.007	1.000
Tres Rios	Archuleta	PUBLIC SERVICE CO - PAGOSA SPRINGS STA	0.10	0.03	0.10	0.000	0.000	0.000
Tres Rios	Dolores	MID-AMERICA PIPELINE CO DOVE CR STA	28.22	2.46	34.37	0.460	0.460	0.010
Tres Rios	Dolores	QEP ENERGY CO - SPARGO NO 2	36.60	0.30	32.70	0.049	0.049	0.003
Tres Rios	Dolores	TRANSCOLORADO GAS TRANS - DOLORES C.S.	17.49	17.58	10.71	0.580	0.580	0.030
Tres Rios	Dolores	WILLIAMS FIELD SERV- JOHNSON AC #1 FACIL	21.20	30.90	13.48	0.413	0.413	0.025
Tres Rios	La Plata	BP AMERICA - PINON COMPRESSOR FACILITY	85.00	24.40	79.60	1.460	1.460	0.088
Tres Rios	Montezuma	KINDER MORGAN CO2 CO. -YELLOW JACKET H10	9.00	2.13	1.96	0.422	0.162	17.000
Tres Rios	Montezuma	MID-AMERICA PIPELINE CO DOLORES STA	25.27	2.20	30.77	0.460	0.460	0.010
Tres Rios	Montezuma	NORTHWEST PIPELINE CORP PLEASANT VIEW	94.73	0.51	7.52	1.142	1.142	1.535
Tres Rios	Montezuma	TRANSCOLORADO GAS TRANS - MANCOS CS	5.97	1.50	2.88	0.150	0.150	0.000
Tres Rios	Montezuma	WILLIAMS FIELD SERVICES- KOSKIE-BRUMLEY	19.41	21.95	6.47	0.443	0.443	0.027
Tres Rios	San Miguel	PATARA MIDSTREAM - ANDY'S MESA	117.46	68.20	43.64	1.963	1.963	0.118
Tres Rios	San Miguel	PATARA MIDSTREAM - HAMILTON CREEK CS	50.86	24.21	27.75	0.426	0.415	0.036
Tres Rios	San Miguel	PATARA OIL & GAS - DOUBLE EAGLE PLANT	57.03	10.35	18.44	0.081	0.081	0.005
Uncompahgre	Gunnison	GUNNISON ENERGY-RAGGED MOUNTAIN C.S.	64.44	55.32	135.60	0.689	0.687	0.053
Uncompahgre	Montrose	TRANSCOLORADO GAS - OLATHE C.S.	12.37	0.51	12.37	0.320	0.320	0.150
Uncompahgre	Montrose	TRANSCOLORADO GAS TRANS - REDVALE CS	17.23	9.42	5.78	0.680	0.680	0.030
Uncompahgre	San Miguel	ROCKY MOUNTAIN NATURAL GAS - NORWOOD C.S	12.20	7.30	25.20	0.213	0.213	0.013
CRV (in Roan Plt.)	Garfield	BARGATH - RABBIT BRUSH C.S.	177.82	64.32	35.31	5.53	5.53	0.30
CRV (in Roan Plt.)	Garfield	BARGATH LLC - ANVIL POINTS CS	131.00	52.60	40.00	2.77	2.77	0.17
CRV (in Roan Plt.)	Garfield	BARGATH LLC - CLOUGH CS	100.80	82.90	40.80	1.98	1.98	0.12
CRV (in Roan Plt.)	Garfield	BARGATH LLC - COTTONWOOD POINT CS	132.60	86.40	132.60	2.27	2.27	0.14
CRV (in Roan Plt.)	Garfield	BARGATH LLC - HAYBARN	54.80	20.30	33.92	2.12	2.12	0.09
CRV (in Roan Plt.)	Garfield	BARGATH LLC - HAYES GULCH	115.80	58.05	34.20	2.35	2.35	0.14

Field Office	County	Facility Name	2011 Emissions (tons/year)					
			NOx	VOC	CO	PM10	PM2.5	SO2
CRV (in Roan Plt.)	Garfield	BARGATH LLC - HEATH CS	220.13	83.88	64.88	4.51	4.51	0.28
CRV (in Roan Plt.)	Garfield	BARGATH LLC - PARACHUTE	299.21	146.32	161.67	9.68	9.68	0.39
CRV (in Roan Plt.)	Garfield	BARGATH LLC - RIFLE STATION	2.80	33.90	2.40	0.00	0.00	0.00
CRV (in Roan Plt.)	Garfield	BARGATH LLC - RILEY CS	115.80	62.40	34.05	2.35	2.35	0.14
CRV (in Roan Plt.)	Garfield	BARGATH LLC - ROAN CLIFFS GAS PLANT	94.60	47.60	66.70	1.80	1.80	0.10
CRV (in Roan Plt.)	Garfield	BARGATH LLC - RULISON CS	116.72	63.71	34.91	0.00	0.00	0.00
CRV (in Roan Plt.)	Garfield	BARGATH LLC - SHARRARD CS	131.84	60.94	64.95	2.98	2.98	0.16
CRV (in Roan Plt.)	Garfield	BARGATH LLC - WEBSTER HILL	172.95	82.59	61.67	5.29	5.29	0.29
CRV (in Roan Plt.)	Garfield	BARGATH LLC - WHEELER GULCH CS	96.50	49.20	28.50	1.90	1.90	0.07
CRV (in Roan Plt.)	Garfield	BARGATH, LLC - WASATCH COMPRESSOR YARD	86.00	82.19	35.60	1.56	1.56	0.09
CRV (in Roan Plt.)	Garfield	ENCANA - RIFLE BOOSTER STATION	43.52	41.73	48.75	1.33	1.32	0.00
CRV (in Roan Plt.)	Garfield	ENCANA (WEST) - MIDDLE FORK C.S.	0.00	422.07	20.10	0.00	0.00	0.00
CRV (in Roan Plt.)	Garfield	ETC CANYON PIPELINE - RIFLE C.S.	238.88	92.78	137.93	4.73	4.73	0.26
CRV (in Roan Plt.)	Garfield	HALLIBURTON ENERGY SVCS	2.66	0.21	0.57	0.18	0.18	0.18
CRV (in Roan Plt.)	Garfield	PUBLIC SERVICE CO - RIFLE GAS PLANT	16.99	18.29	3.33	0.55	0.55	0.01
CRV (in Roan Plt.)	Garfield	WILLIAMS PRODUCTION RMT CO - WEBSTER CS	10.46	2.10	10.46	0.00	0.00	0.00
CRV (in Roan Plt.)	Garfield	WILLIAMS RMT CO - DOE COMPRESSOR STATION	33.10	12.90	3.70	0.09	0.09	0.01
CRV (not in Roan Plt.)	Garfield	ANTERO RES - CASTLE SPRINGS CENTRAL	18.30	6.11	18.30	0.25	0.25	0.02
CRV (not in Roan Plt.)	Garfield	ANTERO RESOURCES - HUNTER MESA COMP STAT	26.14	38.03	31.97	0.00	0.00	0.00
CRV (not in Roan Plt.)	Garfield	BARGATH LLC - CALLAHAN C.S.	102.00	64.45	34.20	2.35	2.35	0.14
CRV (not in Roan Plt.)	Garfield	BARGATH LLC - GRAND VALLEY	94.61	68.70	92.70	1.48	1.41	0.56
CRV (not in Roan Plt.)	Garfield	BARGATH LLC - HOOVER EXPRESS	132.00	71.69	39.00	2.70	2.28	0.18
CRV (not in Roan Plt.)	Garfield	BARGATH LLC - JANGLES	68.00	43.55	22.80	1.55	1.55	0.09
CRV (not in Roan Plt.)	Garfield	BARGATH LLC - STARKEY GULCH CS	132.00	50.95	39.00	2.69	2.69	0.16
CRV (not in Roan Plt.)	Garfield	BARGATH LLC - UNA COMPRESSOR STATION	155.05	65.53	51.83	3.60	3.18	0.45

Field Office	County	Facility Name	2011 Emissions (tons/year)					
			NOx	VOC	CO	PM10	PM2.5	SO2
CRV (not in Roan Plt.)	Garfield	BARGATH, LLC - HYRUP PROD FACILITY	237.62	124.37	82.05	5.77	5.69	0.92
CRV (not in Roan Plt.)	Garfield	BILL BARRETT - BAILEY COMPRESSOR STATION	166.37	193.20	69.30	7.77	7.77	0.44
CRV (not in Roan Plt.)	Garfield	BILL BARRETT CORP - MAMM CREEK CS	292.06	78.37	227.95	15.53	4.44	0.71
CRV (not in Roan Plt.)	Garfield	ENCANA OIL & GAS - HIGH MESA COMP STATIO	99.45	262.57	16.69	1.99	1.99	0.12
CRV (not in Roan Plt.)	Garfield	ENTERPRISE PRODUCTS OP- JACKRABBIT CS	194.08	141.91	134.34	0.01	0.01	0.00
CRV (not in Roan Plt.)	Garfield	ETC CANYON PIPELINE - HOLMES MESA CS	123.73	101.83	82.67	0.00	0.00	0.00
CRV (not in Roan Plt.)	Garfield	ETC CANYON PIPELINE - WALLACE CREEK CS	0.00	18.00	0.00	0.00	0.00	0.00
CRV (not in Roan Plt.)	Garfield	GRAND RIVER GATH - EAST MAMM CREEK CS	138.21	162.64	80.27	3.86	3.86	0.23
CRV (not in Roan Plt.)	Garfield	GRAND RIVER GATHERING - HUNTER MESA CS	148.32	181.24	87.43	0.00	0.00	0.00
CRV (not in Roan Plt.)	Garfield	GRAND RIVER GATHERING - ORCHARD CS	63.20	34.61	20.90	1.07	1.07	0.06
CRV (not in Roan Plt.)	Garfield	GRAND RIVER GATHERING - PUMBA CS	98.35	122.76	140.49	3.56	3.56	0.21
CRV (not in Roan Plt.)	Garfield	NOBLE ENERGY - RULISON STATION	38.84	4.01	14.68	0.84	0.84	0.05
CRV (not in Roan Plt.)	Garfield	PETROLEUM DEVELOPMENT - GARDEN GULCH	26.20	42.03	39.14	1.49	1.49	0.09
CRV (not in Roan Plt.)	Mesa	OXY USA - ALKALI CREEK C.S.	71.56	64.13	56.49	0.04	0.04	0.00
CRV (not in Roan Plt.)	Mesa	SG INTERESTS I - DIVIDE CREEK TREATMENT	39.91	24.14	33.43	1.48	1.48	0.11
White River Valley	Garfield	HUNTER RIDGE - CDP K22 496	29.57	31.78	56.86	0.00	0.00	0.00
White River Valley	Garfield	HUNTER RIDGE ENERGY - STORY GULCH C.S.	155.07	236.41	96.81	0.00	0.00	0.01
White River Valley	Rio Blanco	BARGATH LLC - BLACK SULPHUR CREEK	31.90	0.35	52.20	0.13	0.13	0.01
White River Valley	Rio Blanco	BARGATH LLC - GREASEWOOD CS	96.28	45.82	28.38	1.96	1.96	0.12
White River Valley	Rio Blanco	BARGATH LLC - RYAN GULCH GAS	192.00	127.15	27.30	5.64	5.64	0.34
White River Valley	Rio Blanco	BARGATH LLC - SAGEBRUSH GAS PROCESSING	157.28	44.81	117.04	3.46	3.04	0.20
White River Valley	Rio Blanco	CCES PICEANCE - BUCKSKIN MESA CFS-2	84.70	30.80	21.80	2.70	2.40	0.00
White River Valley	Rio Blanco	ENCANA OIL - EAST DRAGON TRAIL CS	34.66	22.93	41.55	0.53	0.53	0.03
White River Valley	Rio Blanco	ENCANA OIL & GAS - DRAGON TRAIL	431.04	99.33	174.57	13.91	13.89	0.23
White River Valley	Rio Blanco	ENCANA OIL & GAS - PARK CANYON WEST	48.83	40.99	31.73	0.43	0.43	0.03
White River Valley	Rio Blanco	ENCANA OIL & GAS (USA) INC - BULL FORK	39.53	56.80	12.12	0.00	0.00	0.00
White River Valley	Rio Blanco	ENCANA OIL & GAS (USA), INC. - CR 109 CS	2.81	1.03	2.53	0.04	0.04	0.00

Field Office	County	Facility Name	2011 Emissions (tons/year)					
			NOx	VOC	CO	PM10	PM2.5	SO2
White River Valley	Rio Blanco	ENCANA OIL & GAS (USA), INC. - HORSE DRA	10.23	5.93	5.73	0.22	0.22	0.01
White River Valley	Rio Blanco	ENCANA OIL & GAS (USA), INC.- W DRAGON T	60.19	37.96	48.30	0.54	0.54	0.03
White River Valley	Rio Blanco	ENCANA OIL & GAS (USA), INC-W DOUGLAS CR	32.20	97.11	32.20	3.34	3.34	0.07
White River Valley	Rio Blanco	ENTERPRISE GAS PROC - MEEKER GAS PLANT	138.73	317.66	254.06	26.40	26.40	205.27
White River Valley	Rio Blanco	ENTERPRISE GAS-PICEANCE DEV. PROJECT	93.18	208.64	112.70	4.54	4.54	21.83
White River Valley	Rio Blanco	ETC CANYON PIPELINE - N. DOUGLAS CREEK	72.17	54.12	83.19	1.82	0.45	0.10
White River Valley	Rio Blanco	ETC CANYON PIPELINE- CATHEDRAL C.S.	10.77	0.63	1.04	0.02	0.02	0.00
White River Valley	Rio Blanco	ETC CANYON PIPELINE-FOUNDATION CREEK	73.05	69.47	49.87	0.58	0.58	0.03
White River Valley	Rio Blanco	KINDER MORGAN TREATING - MEEKER PLANT	44.96	26.30	43.77	1.56	1.40	0.13
White River Valley	Rio Blanco	NORTHWEST PIPELINE CORP RANGELY STA	382.05	11.61	53.51	2.67	2.67	0.04
White River Valley	Rio Blanco	PICEANCE BASIN GAS GATH - FLETCHER PLANT	45.56	60.67	75.59	1.15	1.15	0.07
White River Valley	Rio Blanco	PUBLIC SERVICE CO GREASEWOOD STATION	24.41	0.17	21.51	0.05	0.05	0.00
White River Valley	Rio Blanco	QUESTAR PIPELINE CO - GREASEWOOD GULCH	51.56	22.50	9.20	2.32	2.32	0.13
White River Valley	Rio Blanco	ROCKY MOUNTAIN NAT GAS - PICEANCE	28.29	31.86	36.01	0.92	0.29	0.02
White River Valley	Rio Blanco	SOUTH-TEX - BASS YELLOW CREEK	14.59	54.91	12.26	0.00	0.00	0.00
White River Valley	Rio Blanco	WEST TEXAS - PICEANCE CREEK GP	61.67	52.39	52.63	1.04	1.03	0.06
White River Valley	Rio Blanco	WHITING OIL & GAS CORP-BOIES RANCH	32.04	37.48	23.06	1.47	1.47	0.09
White River Valley	Rio Blanco	WHITING OIL & GAS -JIMMY GULCH STATION	23.28	19.25	10.03	0.52	0.52	0.03
White River Valley	Rio Blanco	WILLIAMS FIELD - WILLOW CREEK GAS PLANT	199.84	109.89	218.90	37.61	36.90	71.75
White River Valley	Rio Blanco	XTO ENERGY, INC. - PICEANCE CREEK	89.96	91.71	90.02	7.12	6.79	7.85
White River Valley	Mesa	PIONEER NATURAL RES - CSP-3	24.40	5.50	23.09	0.42	0.42	0.02
Canyon Of The Ancients Nm	Montezuma	KINDER MORGAN CO2 CO. -HOVENWEEP CENTRAL	8.60	2.13	1.96	0.422	0.325	16.844

APPENDIX C-6

EPA MOVES Emissions Factor by Field Office, County, and Year

Table F1. Field Office to Representative County On-road Emission Factor Cross-reference.

Field Office	County
Colorado River Valley	Garfield County
Kremmling Field Office	Grand County
Tres Rios Field Office	La Plata County
Grand Junction Field Office	Mesa County
Little Snake Field Office	Moffat County
Uncompahgre Field Office	Montrose County
White River Field Offices	Rio Blanco County

Table F2. On-road Light Duty and Heavy Duty Truck Emission Factors by Representative County and by Project Year.

County	Year	Vehicle Type	Emission Rates (grams/mile)								
			VOC	CO	NOx	PM10	PM2.5	SO2	CO2	CH4	N2O
Garfield County	2011	Light Duty	1.02	12.80	1.49	0.05	0.03	0.01	491	0.05	0.03
Garfield County	2011	Heavy Duty	0.71	3.94	14.41	1.09	0.93	0.02	2403	0.03	0.00
Grand County	2011	Light Duty	1.04	13.58	1.50	0.06	0.04	0.01	495	0.06	0.03
Grand County	2011	Heavy Duty	0.73	4.04	14.69	1.09	0.93	0.02	2404	0.04	0.00
La Plata County	2011	Light Duty	0.99	12.58	1.48	0.05	0.03	0.01	490	0.05	0.03
La Plata County	2011	Heavy Duty	0.72	4.07	14.57	1.09	0.93	0.02	2404	0.04	0.00
Mesa County	2011	Light Duty	0.98	11.99	1.45	0.05	0.02	0.01	488	0.05	0.03
Mesa County	2011	Heavy Duty	0.71	3.99	14.28	1.09	0.93	0.02	2403	0.03	0.00
Moffat County	2011	Light Duty	1.00	12.78	1.47	0.05	0.03	0.01	492	0.05	0.03
Moffat County	2011	Heavy Duty	0.73	4.06	14.54	1.09	0.93	0.02	2404	0.04	0.00
Montrose County	2011	Light Duty	0.97	12.22	1.46	0.05	0.03	0.01	489	0.05	0.03
Montrose County	2011	Heavy Duty	0.72	4.07	14.44	1.09	0.93	0.02	2404	0.04	0.00
Rio Blanco County	2011	Light Duty	1.00	12.68	1.47	0.05	0.03	0.01	491	0.05	0.03
Rio Blanco County	2011	Heavy Duty	0.72	4.03	14.51	1.09	0.93	0.02	2404	0.04	0.00
Garfield County	2012	Light Duty	0.95	12.06	1.39	0.05	0.03	0.01	485	0.05	0.03
Garfield County	2012	Heavy Duty	0.64	3.54	12.74	0.98	0.83	0.02	2402	0.04	0.00
Grand County	2012	Light Duty	0.97	12.83	1.40	0.06	0.03	0.01	489	0.06	0.03
Grand County	2012	Heavy Duty	0.65	3.63	13.00	0.98	0.83	0.02	2404	0.04	0.00
La Plata County	2012	Light Duty	0.92	11.86	1.38	0.05	0.03	0.01	484	0.05	0.03
La Plata County	2012	Heavy Duty	0.65	3.65	12.89	0.98	0.83	0.02	2404	0.04	0.00
Mesa County	2012	Light Duty	0.91	11.28	1.35	0.05	0.02	0.01	481	0.04	0.03
Mesa County	2012	Heavy Duty	0.64	3.58	12.63	0.98	0.83	0.02	2403	0.04	0.00
Moffat County	2012	Light Duty	0.93	12.05	1.37	0.05	0.03	0.01	485	0.05	0.034

County	Year	Vehicle Type	Emission Rates (grams/mile)								
			VOC	CO	NOx	PM10	PM2.5	SO2	CO2	CH4	N2O
Moffat County	2012	Heavy Duty	0.65	3.65	12.86	0.98	0.83	0.02	2404	0.04	0.003
Montrose County	2012	Light Duty	0.91	11.51	1.36	0.05	0.03	0.01	482	0.05	0.033
Montrose County	2012	Heavy Duty	0.65	3.66	12.77	0.98	0.83	0.02	2404	0.04	0.003
Rio Blanco County	2012	Light Duty	0.93	11.95	1.37	0.05	0.03	0.01	484	0.05	0.033
Rio Blanco County	2012	Heavy Duty	0.64	3.62	12.84	0.98	0.83	0.02	2404	0.04	0.004
Garfield County	2013	Light Duty	0.89	11.40	1.29	0.05	0.03	0.01	477	0.05	0.033
Garfield County	2013	Heavy Duty	0.56	3.15	11.19	0.87	0.72	0.02	2402	0.05	0.003
Grand County	2013	Light Duty	0.91	12.18	1.30	0.06	0.03	0.01	481	0.05	0.032
Grand County	2013	Heavy Duty	0.57	3.24	11.41	0.87	0.72	0.02	2404	0.05	0.004
La Plata County	2013	Light Duty	0.86	11.22	1.28	0.05	0.03	0.01	476	0.05	0.033
La Plata County	2013	Heavy Duty	0.57	3.26	11.32	0.87	0.72	0.02	2404	0.05	0.004
Mesa County	2013	Light Duty	0.85	10.66	1.26	0.05	0.02	0.01	473	0.04	0.033
Mesa County	2013	Heavy Duty	0.56	3.19	11.09	0.87	0.72	0.02	2403	0.05	0.003
Moffat County	2013	Light Duty	0.87	11.41	1.27	0.05	0.03	0.01	477	0.05	0.032
Moffat County	2013	Heavy Duty	0.57	3.25	11.30	0.87	0.72	0.02	2404	0.05	0.003
Montrose County	2013	Light Duty	0.84	10.88	1.26	0.05	0.03	0.01	474	0.04	0.030
Montrose County	2013	Heavy Duty	0.57	3.27	11.22	0.87	0.72	0.02	2404	0.05	0.003
Rio Blanco County	2013	Light Duty	0.87	11.31	1.27	0.05	0.03	0.01	477	0.05	0.030
Rio Blanco County	2013	Heavy Duty	0.57	3.23	11.27	0.87	0.72	0.02	2404	0.05	0.004
Garfield County	2014	Light Duty	0.83	10.78	1.19	0.05	0.03	0.01	468	0.05	0.031
Garfield County	2014	Heavy Duty	0.49	2.78	9.83	0.78	0.63	0.02	2402	0.05	0.003
Grand County	2014	Light Duty	0.85	11.55	1.20	0.06	0.03	0.01	472	0.05	0.030
Grand County	2014	Heavy Duty	0.50	2.86	10.03	0.78	0.63	0.02	2404	0.06	0.004
La Plata County	2014	Light Duty	0.80	10.61	1.18	0.05	0.03	0.01	468	0.04	0.030
La Plata County	2014	Heavy Duty	0.50	2.89	9.95	0.78	0.63	0.02	2404	0.06	0.004
Mesa County	2014	Light Duty	0.79	10.06	1.16	0.05	0.02	0.01	465	0.04	0.030
Mesa County	2014	Heavy Duty	0.49	2.82	9.75	0.78	0.63	0.02	2403	0.05	0.003
Moffat County	2014	Light Duty	0.81	10.80	1.18	0.05	0.03	0.01	469	0.05	0.029
Moffat County	2014	Heavy Duty	0.50	2.88	9.93	0.78	0.63	0.02	2404	0.06	0.003
Montrose County	2014	Light Duty	0.79	10.28	1.17	0.05	0.02	0.01	466	0.04	0.028
Montrose County	2014	Heavy Duty	0.50	2.89	9.86	0.78	0.63	0.02	2404	0.05	0.003
Rio Blanco County	2014	Light Duty	0.81	10.70	1.18	0.05	0.03	0.01	468	0.05	0.028
Rio Blanco County	2014	Heavy Duty	0.50	2.86	9.91	0.78	0.63	0.02	2404	0.05	0.004
Garfield County	2015	Light Duty	0.77	10.17	1.10	0.05	0.03	0.01	460	0.04	0.028
Garfield County	2015	Heavy Duty	0.43	2.44	8.61	0.69	0.55	0.02	2402	0.06	0.003
Grand County	2015	Light Duty	0.79	10.95	1.11	0.06	0.03	0.01	463	0.05	0.027
Grand County	2015	Heavy Duty	0.44	2.53	8.79	0.69	0.55	0.02	2404	0.06	0.004
La Plata County	2015	Light Duty	0.75	10.02	1.09	0.05	0.03	0.01	459	0.04	0.027

County	Year	Vehicle Type	Emission Rates (grams/mile)								
			VOC	CO	NOx	PM10	PM2.5	SO2	CO2	CH4	N2O
La Plata County	2015	Heavy Duty	0.44	2.55	8.72	0.69	0.55	0.02	2404	0.06	0.004
Mesa County	2015	Light Duty	0.74	9.49	1.07	0.05	0.02	0.01	456	0.04	0.027
Mesa County	2015	Heavy Duty	0.43	2.48	8.54	0.69	0.55	0.02	2403	0.06	0.003
Moffat County	2015	Light Duty	0.76	10.21	1.09	0.05	0.03	0.01	460	0.04	0.026
Moffat County	2015	Heavy Duty	0.44	2.54	8.70	0.69	0.55	0.02	2404	0.06	0.003
Montrose County	2015	Light Duty	0.74	9.70	1.07	0.05	0.02	0.01	457	0.04	0.025
Montrose County	2015	Heavy Duty	0.44	2.55	8.64	0.69	0.55	0.02	2404	0.06	0.003
Rio Blanco County	2015	Light Duty	0.76	10.11	1.08	0.05	0.03	0.01	459	0.04	0.025
Rio Blanco County	2015	Heavy Duty	0.44	2.52	8.68	0.69	0.55	0.02	2404	0.06	0.004
Garfield County	2016	Light Duty	0.71	9.52	1.01	0.05	0.02	0.01	450	0.04	0.026
Garfield County	2016	Heavy Duty	0.37	2.14	7.54	0.62	0.47	0.02	2402	0.06	0.003
Grand County	2016	Light Duty	0.73	10.29	1.02	0.06	0.03	0.01	453	0.05	0.025
Grand County	2016	Heavy Duty	0.38	2.22	7.70	0.62	0.47	0.02	2404	0.06	0.003
La Plata County	2016	Light Duty	0.69	9.38	1.00	0.05	0.03	0.01	449	0.04	0.025
La Plata County	2016	Heavy Duty	0.38	2.24	7.63	0.62	0.47	0.02	2404	0.06	0.004
Mesa County	2016	Light Duty	0.68	8.86	0.98	0.05	0.02	0.01	446	0.04	0.025
Mesa County	2016	Heavy Duty	0.37	2.18	7.47	0.62	0.47	0.02	2403	0.06	0.003
Moffat County	2016	Light Duty	0.70	9.57	1.00	0.05	0.03	0.01	450	0.04	0.024
Moffat County	2016	Heavy Duty	0.38	2.24	7.62	0.62	0.47	0.02	2404	0.06	0.003
Montrose County	2016	Light Duty	0.68	9.08	0.99	0.05	0.02	0.01	448	0.04	0.023
Montrose County	2016	Heavy Duty	0.38	2.25	7.56	0.62	0.47	0.02	2404	0.06	0.003
Rio Blanco County	2016	Light Duty	0.70	9.47	1.00	0.05	0.03	0.01	450	0.04	0.023
Rio Blanco County	2016	Heavy Duty	0.38	2.21	7.60	0.62	0.47	0.02	2404	0.06	0.004
Garfield County	2017	Light Duty	0.67	9.10	0.93	0.05	0.02	0.01	441	0.04	0.024
Garfield County	2017	Heavy Duty	0.32	1.87	6.58	0.55	0.41	0.02	2402	0.06	0.003
Grand County	2017	Light Duty	0.68	9.87	0.94	0.06	0.03	0.01	444	0.04	0.023
Grand County	2017	Heavy Duty	0.33	1.96	6.72	0.55	0.41	0.02	2404	0.06	0.003
La Plata County	2017	Light Duty	0.64	8.97	0.92	0.05	0.03	0.01	440	0.04	0.023
La Plata County	2017	Heavy Duty	0.33	1.98	6.67	0.55	0.41	0.02	2404	0.06	0.004
Mesa County	2017	Light Duty	0.64	8.46	0.90	0.04	0.02	0.01	437	0.04	0.023
Mesa County	2017	Heavy Duty	0.32	1.92	6.52	0.55	0.41	0.02	2403	0.06	0.003
Moffat County	2017	Light Duty	0.65	9.16	0.92	0.05	0.03	0.01	441	0.04	0.022
Moffat County	2017	Heavy Duty	0.33	1.97	6.65	0.55	0.41	0.02	2404	0.06	0.003
Montrose County	2017	Light Duty	0.63	8.67	0.91	0.05	0.02	0.01	438	0.04	0.021
Montrose County	2017	Heavy Duty	0.33	1.98	6.60	0.55	0.41	0.02	2404	0.06	0.003
Rio Blanco County	2017	Light Duty	0.65	9.06	0.92	0.05	0.03	0.01	440	0.04	0.021
Rio Blanco County	2017	Heavy Duty	0.33	1.95	6.64	0.55	0.41	0.02	2403	0.06	0.003
Garfield County	2018	Light Duty	0.62	8.72	0.86	0.05	0.02	0.01	432	0.04	0.022

County	Year	Vehicle Type	Emission Rates (grams/mile)								
			VOC	CO	NOx	PM10	PM2.5	SO2	CO2	CH4	N2O
Garfield County	2018	Heavy Duty	0.28	1.64	5.75	0.49	0.35	0.02	2402	0.06	0.003
Grand County	2018	Light Duty	0.64	9.49	0.87	0.05	0.03	0.01	436	0.04	0.021
Grand County	2018	Heavy Duty	0.28	1.72	5.88	0.49	0.35	0.02	2404	0.07	0.003
La Plata County	2018	Light Duty	0.60	8.60	0.85	0.05	0.02	0.01	431	0.04	0.021
La Plata County	2018	Heavy Duty	0.28	1.74	5.83	0.49	0.35	0.02	2404	0.07	0.004
Mesa County	2018	Light Duty	0.60	8.09	0.83	0.04	0.02	0.01	429	0.04	0.021
Mesa County	2018	Heavy Duty	0.28	1.68	5.70	0.49	0.35	0.02	2403	0.06	0.003
Moffat County	2018	Light Duty	0.61	8.79	0.85	0.05	0.03	0.01	432	0.04	0.021
Moffat County	2018	Heavy Duty	0.28	1.73	5.82	0.49	0.35	0.02	2404	0.07	0.003
Montrose County	2018	Light Duty	0.59	8.30	0.84	0.05	0.02	0.01	430	0.04	0.020
Montrose County	2018	Heavy Duty	0.28	1.74	5.77	0.49	0.35	0.02	2404	0.07	0.003
Rio Blanco County	2018	Light Duty	0.61	8.69	0.85	0.05	0.03	0.01	432	0.04	0.020
Rio Blanco County	2018	Heavy Duty	0.28	1.71	5.80	0.49	0.35	0.02	2403	0.07	0.003
Garfield County	2019	Light Duty	0.58	8.37	0.79	0.05	0.02	0.01	424	0.04	0.020
Garfield County	2019	Heavy Duty	0.24	1.43	5.04	0.44	0.30	0.02	2402	0.06	0.003
Grand County	2019	Light Duty	0.59	9.14	0.80	0.05	0.03	0.01	427	0.04	0.019
Grand County	2019	Heavy Duty	0.24	1.51	5.15	0.44	0.30	0.02	2404	0.07	0.003
La Plata County	2019	Light Duty	0.56	8.26	0.78	0.05	0.02	0.01	423	0.04	0.020
La Plata County	2019	Heavy Duty	0.24	1.53	5.11	0.44	0.30	0.02	2404	0.07	0.004
Mesa County	2019	Light Duty	0.56	7.76	0.77	0.04	0.02	0.01	421	0.03	0.020
Mesa County	2019	Heavy Duty	0.24	1.47	5.00	0.44	0.30	0.02	2403	0.07	0.003
Moffat County	2019	Light Duty	0.57	8.45	0.78	0.05	0.03	0.01	424	0.04	0.019
Moffat County	2019	Heavy Duty	0.24	1.52	5.10	0.44	0.30	0.02	2404	0.07	0.003
Montrose County	2019	Light Duty	0.56	7.97	0.77	0.05	0.02	0.01	422	0.03	0.018
Montrose County	2019	Heavy Duty	0.24	1.53	5.06	0.44	0.30	0.02	2404	0.07	0.003
Rio Blanco County	2019	Light Duty	0.57	8.35	0.78	0.05	0.03	0.01	424	0.04	0.018
Rio Blanco County	2019	Heavy Duty	0.24	1.50	5.09	0.44	0.30	0.02	2403	0.07	0.003
Garfield County	2020	Light Duty	0.55	8.06	0.73	0.05	0.02	0.01	416	0.04	0.018
Garfield County	2020	Heavy Duty	0.20	1.26	4.43	0.40	0.26	0.02	2402	0.07	0.003
Grand County	2020	Light Duty	0.56	8.84	0.74	0.05	0.03	0.01	420	0.04	0.018
Grand County	2020	Heavy Duty	0.21	1.34	4.54	0.40	0.26	0.02	2403	0.07	0.003
La Plata County	2020	Light Duty	0.53	7.96	0.73	0.05	0.02	0.01	416	0.04	0.018
La Plata County	2020	Heavy Duty	0.21	1.36	4.50	0.40	0.26	0.02	2404	0.07	0.003
Mesa County	2020	Light Duty	0.53	7.47	0.71	0.04	0.02	0.01	413	0.03	0.018
Mesa County	2020	Heavy Duty	0.20	1.30	4.40	0.40	0.26	0.02	2403	0.07	0.003
Moffat County	2020	Light Duty	0.54	8.15	0.73	0.05	0.03	0.01	417	0.04	0.018
Moffat County	2020	Heavy Duty	0.21	1.35	4.49	0.40	0.26	0.02	2404	0.07	0.003
Montrose County	2020	Light Duty	0.52	7.67	0.72	0.05	0.02	0.01	414	0.03	0.017

County	Year	Vehicle Type	Emission Rates (grams/mile)								
			VOC	CO	NOx	PM10	PM2.5	SO2	CO2	CH4	N2O
Montrose County	2020	Heavy Duty	0.21	1.36	4.46	0.40	0.26	0.02	2404	0.07	0.003
Rio Blanco County	2020	Light Duty	0.54	8.05	0.72	0.05	0.03	0.01	416	0.04	0.017
Rio Blanco County	2020	Heavy Duty	0.21	1.33	4.48	0.40	0.26	0.02	2403	0.07	0.003
Garfield County	2021	Light Duty	0.52	7.80	0.68	0.05	0.02	0.01	409	0.04	0.017
Garfield County	2021	Heavy Duty	0.17	1.12	3.94	0.36	0.23	0.02	2402	0.07	0.003
Grand County	2021	Light Duty	0.53	8.57	0.69	0.05	0.03	0.01	413	0.04	0.017
Grand County	2021	Heavy Duty	0.18	1.19	4.04	0.36	0.23	0.02	2403	0.07	0.003
La Plata County	2021	Light Duty	0.50	7.70	0.67	0.05	0.02	0.01	409	0.03	0.017
La Plata County	2021	Heavy Duty	0.18	1.21	4.00	0.36	0.23	0.02	2404	0.07	0.003
Mesa County	2021	Light Duty	0.50	7.22	0.66	0.04	0.02	0.01	406	0.03	0.017
Mesa County	2021	Heavy Duty	0.18	1.16	3.91	0.36	0.23	0.02	2403	0.07	0.003
Moffat County	2021	Light Duty	0.51	7.89	0.67	0.05	0.03	0.01	410	0.03	0.016
Moffat County	2021	Heavy Duty	0.18	1.21	3.99	0.36	0.23	0.02	2404	0.07	0.003
Montrose County	2021	Light Duty	0.49	7.42	0.66	0.05	0.02	0.01	407	0.03	0.016
Montrose County	2021	Heavy Duty	0.18	1.21	3.96	0.36	0.23	0.02	2404	0.07	0.003
Rio Blanco County	2021	Light Duty	0.51	7.79	0.67	0.05	0.02	0.01	409	0.03	0.016
Rio Blanco County	2021	Heavy Duty	0.18	1.19	3.98	0.36	0.23	0.02	2403	0.07	0.003

APPENDIX D

**CARMMS Technical Memorandum
Draft CARMMS Coal and Uranium/Vanadium Mining Emissions
June 21, 2013**

June 21, 2013

MEMORANDUM

To: Chad Meister and Forrest Cook, BLM Colorado State Office
From: John Grant ENVIRON, Jim Zapert Carter Lake Consulting, Ralph Morris ENVIRON
Subject: Draft CARMMS Coal and Uranium/Vanadium Mining Emissions

INTRODUCTION

The purpose of this document is to explain the sources of emissions and methodology used to compile Western Colorado coal and uranium/vanadium mining emissions. Emissions from coal and uranium/vanadium mines under federal jurisdiction have been developed for the Western Colorado Air Resource Management Modeling Study (West-CARMMS). The primary sources used to compile these emissions are Environmental Assessments and Environmental Impact Statements developed for individual mines as well as 2011 reported emissions from Colorado Department of Public Health (CDPHE) Air Pollutant Emission Notices (APENs).

These mining emissions will be used in baseline and future-year emissions inventories as estimates of coal and uranium mining emissions under Task 2 for the Western Colorado Bureau of Land Management (BLM) planning areas (see Figure 1-1).

Emissions were not estimated for mines not under federal jurisdiction; emissions from these mines in the West-CARMMS will be taken from existing inventory estimates. To avoid double counting in air quality modeling, emissions were not estimated for on-road or off-road mobile sources.

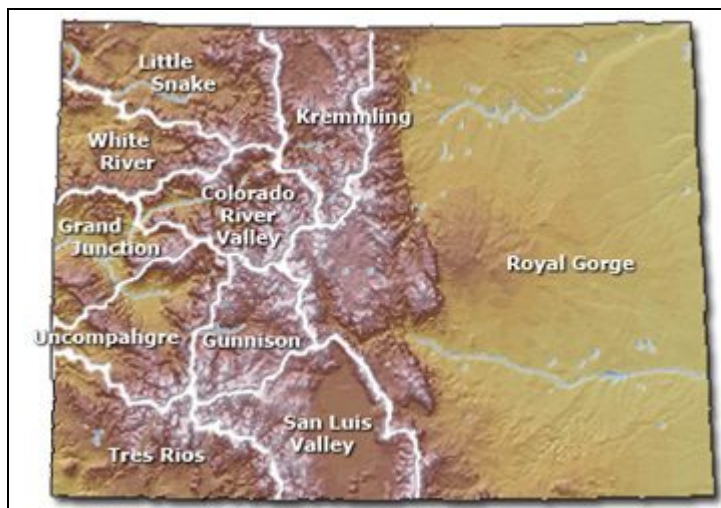


Figure 1-1. Colorado Field Office Planning Areas.

Pollutants

The emissions include estimates of criteria air pollutants (CAPs), greenhouse gases (GHGs), and hazardous air pollutants (HAPs) as follows:

- Criteria Pollutants
 - Carbon monoxide (CO)
 - Nitrogen oxides (NO_x)
 - Particulate matter less than or equal to 10 microns in diameter (PM₁₀)
 - Particulate matter less than or equal to 2.5 microns in diameter (PM_{2.5})
 - Sulfur dioxide (SO₂)
 - Volatile Organic Compounds (VOCs)
- Greenhouse Gases
 - Carbon dioxide (CO₂)
 - Methane (CH₄)
 - Nitrous oxide (N₂O)
- Hazardous Air Pollutants (HAPs)

While lead (pb) is a criteria pollutant, emissions of lead in the BLM western Colorado planning areas are expected to be extremely low and are therefore not included in this analysis.

HAP emissions were estimated for each emissions source.

Anthropogenic greenhouse gas emission inventories typically include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and fluorinated gases. Fluorinated gases are not expected to be emitted in appreciable quantities by any category considered in this emission inventory and were therefore not included in this analysis.

Temporal

The calculators estimate annual emissions associated coal and uranium/vanadium mining. Per the West-CARMMS scope of work, base year emissions are estimated for 2011 with annual emission forecasts to 2021.

EMISSIONS ESTIMATION

Coal Mining

Annual base year emissions from coal mining were estimated for the coal mines in Western Colorado under federal jurisdiction. As mentioned above, the mining emission estimates are not inclusive of mobile sources to avoid double counting with the mobile sources emissions in the air quality modeling inventory. Additionally, lacking any data upon which to base emission estimates, we have not accounted for potential growth in Kremmling Field Office surface coal mining in Jackson County where the U.S. Geological Survey (USGS) has defined the McCallum area as a known recoverable coal resource area. Table 1 provides a listing of the Western Colorado mines under BLM jurisdiction and the sources upon which emissions were estimated for those mines. Appendix D-1 provides emission estimates by year and mine.

Table 1. Coal mine emissions estimation methodology.

Mine Name (Field Office)	Emission Estimation Methodology
Book Cliffs Area (Grand Junction)	<p>Base Year 2011: Non-operational, zero emissions.</p> <p>Future Years 2012-2021: Per the Grand Junction Field Office Draft Regional Management Plant Air Quality Technical Support document (ENVIRON, 2012a), the Book Cliffs area is assumed to have three additional new mines with estimated annual production of 2,000,000 tons/year in the future. Mines are assumed to come online in 2017, 2019, and 2021. Emissions for each mine are assumed to be similar to the Red Cliff Mine Environmental Impact Statement estimates (BLM, 2009) with a scalar of 25% to account for smaller production.</p>
McClane (Grand Junction)	<p>Base Year 2011: Non-operational, zero emissions.</p> <p>Future Years 2012-2021: Per the Grand Junction Field Office Draft Regional Management Plant Air Quality Technical Support document (ENVIRON, 2012a), the McClane mine is assumed operational from 2015 to 2021. Emissions are assumed to be at pre-December 2010 levels (BLM, 2012a).</p>
Oak Mesa Area (Uncompahgre)	<p>Base Year 2011: CDPHE APEN emissions (CDPHE, 2013).</p> <p>Future Years 2012-2021: Assume emissions are at levels estimated in the following Environmental Assessment documents: Bowie #2 (BLM, 2012c), West Elk (BLM, 2012d), and Elk Creek (BLM, 2012f) and that emissions remain constant in the 2012-2021 period. The Uncompahgre Coal Resource and Development Potential Report (BLM, 2010), indicated that Somerset Coal Field production is likely to remain stable at recent levels into the future (ENVIRON, 2012b).</p>
King (Tres Rios)	<p>Base Year 2011: CDPHE APEN emissions (CDPHE, 2013).</p> <p>Future Years 2012-2021: Assume emissions at permitted levels in future years (CDPHE, 2011).</p>
Foidel (Kremmling)	<p>Base Year 2011, Future Year 2012: CDPHE APEN emissions (CDPHE, 2013).</p> <p>Future Years 2013-2021: Assume emissions are at levels estimated in the draft Environment Assessment (BLM 2013a).</p>
Deserado (White River)	<p>Base Year 2011: CDPHE APEN emissions (CDPHE, 2013).</p> <p>Future Years 2012-2021: Assume emissions are at levels estimated in the draft Environment Assessment (BLM 2013b).</p>
Trapper (Little Snake)	<p>Base Year 2011: CDPHE APEN emissions (CDPHE, 2013).</p> <p>Future Years 2012-2021: Assume emissions remain constant at CDPHE 2011 APEN levels.</p>
Colowyo (Little Snake)	<p>Base Year 2011: CDPHE APEN emissions (CDPHE, 2013).</p> <p>Future Years 2012-2021: Assume emissions remain constant at CDPHE 2011 APEN levels.</p>
Sage Creek (Little Snake)	<p>Base Year 2011: Non-operational, zero emissions.</p> <p>Future Years 2012-2021: Assume mining begins in 2013 with constant emissions to 2021 at levels estimated in the draft Environment Assessment (BLM 2013c).</p>

Uranium/Vanadium Mining

Annual emissions from uranium/vanadium mining were estimated according to the number of mines constructed and producing in a given year combined with estimates of emissions per mine from discrete emission producing activities: wind erosion, fugitive dust, and stationary engines. Activity inputs such as the equipment operation, tons of material processed, and disturbed area were taken primarily from the Whirlwind Mine EA (BLM, 2008). The estimated number of future uranium mines in operation in the Grand Junction Field Office and Uncompahgre Field Office were taken from ENVIRON (2012a) and ENVIRON (2012b) and are shown in Table 2. Emissions results are presented in Appendix D-2.

Table 2. Schedule of uranium/vanadium mines in production.

Year	Uranium Mining Facilities, GJFO (source: ENVIRON, 2012a)	Uranium Mining Facilities, UFO (source: ENVIRON, 2012b)
2011-2012	0	0
2013	1	1
2014	3	3
2015	5	5
2016	7	7
2017	9	9
2018	10	10
2019	11	11
2020	12	12
2021	13	13
2022	14	14
2023	15	15
2024	16	16
2025	17	17
2026	18	18
2027	19	19
2028	20	20
2029	20	20
2030	20	20

Wind Erosion

Wind erosion dust emissions were estimated based on AP-42 guidance for the estimation of emissions from industrial wind erosion (USEPA, 2006b) based on Equation 1:

$$E_{dust,i} = \frac{k \times P \times M \times N}{907,185} \quad \text{Equation (1)}$$

where:

$E_{dust,i}$ are dust emissions for pollutant i from construction wind erosion [ton/mine]

k is the particle size multiplies [0.5 for PM_{10} and 0.075 from $PM_{2.5}$]

P is the erosion potential [g/m^2]

M is the number of disturbed acres [m^2 /pad]

N is the number of disturbances

907,185 is a mass unit conversion [g/ton]

The erosions potential is a function of the wind friction velocity, as shown in Equation 2 and 3:

$$P = 58 \times (u^* - u_t)^2 + 25(u^* - u_t) \quad \text{Equation (2)}$$

where:

u^* is the friction velocity (m/s)

u_t is the threshold friction velocity (m/s)

$$P = 0 \quad \text{for} \quad (u^* \leq u_t) \quad \text{Equation (3)}$$

Friction velocity estimates (u^*) were made by multiplying the average annual fastest wind speed from Uncompahgre, Colorado from 1947 to 1979 by 0.053 per AP-42 guidance (USEPA, 2006b).

Fugitive Dust

Fugitive dust emissions from ventilation and surface facilities were taken from Whirlwind Mine Environmental Assessment (BLM, 2008) permit not-to-exceed values.

Stationary Engines

This category refers to emissions associated with stationary internal combustion engines used in uranium mining. Emission estimates for NO_x were taken from the Whirlwind Mine Environmental Assessment permit not-to-exceed values (BLM, 2008). Emission estimates were not available in the Whirlwind Mine Environmental Assessment (BLM, 2008) for other pollutants. Emissions of other pollutants were estimated based on the EPA NONROAD2008a model (USEPA, 2009b) except for N₂O which was estimated based on the 2009 API O&G GHG Methodologies Compendium, Tables 4-13 and 4-17 (API, 2009).

Emissions on per piece of equipment were estimated according to Equation 74:

$$E_{engine,i} = \frac{EF_i \times HP \times LF \times t_{event} \times n}{907,185} \quad \text{Equation (4)}$$

where:

E_{engine} are emissions of pollutant i [ton/equipment]

EF_i is the emissions factor of pollutant i [g/hp-hr]

HP is the horsepower [hp]

LF is the load factor

t_{event} is the number of hours the engine is used [hr/pad]

907,185 is the mass unit conversion [g/ton]

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APPENDIX D-1

Coal Mining Emissions

Table A1. 2011 to 2021 Coal Mine Emissions for mines in Western Colorado under federal jurisdiction (tons/year).

Year	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/year)
Book Cliffs (Grand Junction Field Office)												
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0
2017	1	3	20	6	2	0	2,616	21,278	0	0	449,496	407,891
2018	1	3	20	6	2	0	2,616	21,278	0	0	449,496	407,891
2019	2	5	40	12	4	0	5,231	42,556	0	0	898,992	815,783
2020	2	5	40	12	4	0	5,231	42,556	0	0	898,992	815,783
2021	3	8	60	18	5	0	7,847	63,833	0	0	1,348,489	1,223,674
McClane (Grand Junction Field Office)												
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757
2016	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757
2017	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757
2018	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757
2019	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757
2020	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757
2021	0	0	0	13	0.3	0	0	3,818	0	0	80,178	72,757

Year	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/year)
Oak Mesa Area (Uncompahgre Field Office)												
2011	2	15	14	291	81	0.2	44,671	80,619	0.8	0.2	1,737,918	1,577,058
2012	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2013	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2014	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2015	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2016	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2017	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2018	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2019	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2020	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
2021	13	41	55	513	190	0.8	53,176	140,290	0.9	1.3	2,999,549	2,721,914
King (Tres Rios Field Office)												
2011	0	0	0	15	14	0	0	0	0	0	0	0
2012	0	0	0	25	24	0	0	0	0	0	0	0
2013	0	0	0	25	24	0	0	0	0	0	0	0
2014	0	0	0	25	24	0	0	0	0	0	0	0
2015	0	0	0	25	24	0	0	0	0	0	0	0
2016	0	0	0	25	24	0	0	0	0	0	0	0
2017	0	0	0	25	24	0	0	0	0	0	0	0
2018	0	0	0	25	24	0	0	0	0	0	0	0
2019	0	0	0	25	24	0	0	0	0	0	0	0
2020	0	0	0	25	24	0	0	0	0	0	0	0
2021	0	0	0	25	24	0	0	0	0	0	0	0

Year	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/year)
Foidel (Kremmling Field Office)												
2011	0	1	4	259	54	0	*	*	*	0	*	*
2012	0	1	4	259	54	0	*	*	*	0	*	*
2013	5	6	11	161	33	0	36,878	1,257	0	0	63,298	57,439
2014	5	6	11	161	33	0	36,878	1,257	0	0	63,298	57,439
2015	5	6	11	161	33	0	36,878	1,257	0	0	63,298	57,439
2016	5	6	11	161	33	0	36,878	1,257	0	0	63,298	57,439
2017	5	6	11	161	33	0	36,878	1,257	0	0	63,298	57,439
2018	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
Deserado (White River Field Office)												
2011	0	0	0	119	13	0	*	*	*	0	*	*
2012	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2013	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2014	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2015	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2016	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2017	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2018	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2019	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2020	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383
2021	5	6	11	126	15	0	29,498	923	0	0	48,910	44,383

Year	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/year)
Trapper (Little Snake Field Office)												
2011	0	452	115	852	251	0	*	*	*	0	*	*
2012	0	452	115	852	251	0	*	*	*	0	*	*
2013	0	452	115	852	251	0	*	*	*	0	*	*
2014	0	452	115	852	251	0	*	*	*	0	*	*
2015	0	452	115	852	251	0	*	*	*	0	*	*
2016	0	452	115	852	251	0	*	*	*	0	*	*
2017	0	452	115	852	251	0	*	*	*	0	*	*
2018	0	452	115	852	251	0	*	*	*	0	*	*
2019	0	452	115	852	251	0	*	*	*	0	*	*
2020	0	452	115	852	251	0	*	*	*	0	*	*
2021	0	452	115	852	251	0	*	*	*	0	*	*
Colowyo (Little Snake Field Office)												
2011	0	0	0	1,700	252	0	*	*	*	0	*	*
2012	0	0	0	1,700	252	0	*	*	*	0	*	*
2013	0	0	0	1,700	252	0	*	*	*	0	*	*
2014	0	0	0	1,700	252	0	*	*	*	0	*	*
2015	0	0	0	1,700	252	0	*	*	*	0	*	*
2016	0	0	0	1,700	252	0	*	*	*	0	*	*
2017	0	0	0	1,700	252	0	*	*	*	0	*	*
2018	0	0	0	1,700	252	0	*	*	*	0	*	*
2019	0	0	0	1,700	252	0	*	*	*	0	*	*
2020	0	0	0	1,700	252	0	*	*	*	0	*	*
2021	0	0	0	1,700	252	0	*	*	*	0	*	*

Year	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/year)
Sage Creek (Little Snake Field Office)												
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2014	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2015	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2016	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2017	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2018	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2019	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2020	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480
2021	4	3	4	112	15	0	4,178	298	0	0	10,447	9,480

* Greenhouse gas emissions not available for all years for the Trapper and Colowyo mines, in 2011 for the Deserado mine, and in 2011 and 2012 for the Foidel mine.

APPENDIX D-2

Uranium/Vanadium Mining Emissions

Table B1. Grand Junction Field Office Uranium/Vanadium Mine Emissions (tons/year).

Year	Mines	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/ year)
2011	0	0	0	0	0	0	0.0	0	0.0	0.0	0.0	0	0
2012	0	0	0	0	0	0	0.0	0	0.0	0.0	0.0	0	0
2013	1	1	4	12	14	13	0.2	1,077	0.0	0.0	0.1	1,080	980
2014	3	3	13	37	42	39	0.7	3,231	0.0	0.0	0.3	3,240	2,940
2015	5	5	22	62	69	66	1.2	5,386	0.1	0.0	0.5	5,401	4,901
2016	7	7	31	86	97	92	1.6	7,540	0.1	0.1	0.7	7,561	6,861
2017	9	9	40	111	125	118	2.1	9,694	0.1	0.1	0.9	9,721	8,821
2018	10	10	44	123	139	131	2.3	10,771	0.2	0.1	1.0	10,801	9,801
2019	11	11	49	135	153	145	2.6	11,848	0.2	0.1	1.1	11,881	10,782
2020	12	12	53	148	167	158	2.8	12,925	0.2	0.1	1.2	12,961	11,762
2021	13	13	57	160	181	171	3.0	14,003	0.2	0.1	1.3	14,041	12,742
2022	14	14	62	172	194	184	3.3	15,080	0.2	0.1	1.4	15,122	13,722
2023	15	15	66	185	208	197	3.5	16,157	0.2	0.1	1.5	16,202	14,702
2024	16	16	71	197	222	210	3.7	17,234	0.2	0.1	1.6	17,282	15,682
2025	17	17	75	209	236	223	4.0	18,311	0.3	0.1	1.7	18,362	16,662
2026	18	18	79	221	250	236	4.2	19,388	0.3	0.2	1.8	19,442	17,642
2027	19	19	84	234	264	250	4.5	20,465	0.3	0.2	1.9	20,522	18,623
2028	20	20	88	246	278	263	4.7	21,542	0.3	0.2	2.0	21,602	19,603
2029	20	20	88	246	278	263	4.7	21,542	0.3	0.2	2.0	21,602	19,603
2030	20	20	88	246	278	263	4.7	21,542	0.3	0.2	2.0	21,602	19,603

Table B2. Uncompahgre Field Office Uranium/Vanadium Mine Emissions (tons/year).

Year	Mines	VOC (short tons/year)	CO (short tons/year)	NOx (short tons/year)	PM10 (short tons/year)	PM2.5 (short tons/year)	SO2 (short tons/year)	CO2 (short tons/year)	CH4 (short tons/year)	N2O (short tons/year)	HAPs (short tons/year)	CO2eq (short tons/year)	CO2eq (metric tonnes/ year)
2011	0	0	0	0	0	0	0.0	0	0.0	0.0	0.0	0	0
2012	0	0	0	0	0	0	0.0	0	0.0	0.0	0.0	0	0
2013	1	1	4	12	14	13	0.2	1,077	0.0	0.0	0.1	1,080	980
2014	3	3	13	37	42	39	0.7	3,231	0.0	0.0	0.3	3,240	2,940
2015	5	5	22	62	69	66	1.2	5,386	0.1	0.0	0.5	5,401	4,901
2016	7	7	31	86	97	92	1.6	7,540	0.1	0.1	0.7	7,561	6,861
2017	9	9	40	111	125	118	2.1	9,694	0.1	0.1	0.9	9,721	8,821
2018	10	10	44	123	139	131	2.3	10,771	0.2	0.1	1.0	10,801	9,801
2019	11	11	49	135	153	145	2.6	11,848	0.2	0.1	1.1	11,881	10,782
2020	12	12	53	148	167	158	2.8	12,925	0.2	0.1	1.2	12,961	11,762
2021	13	13	57	160	181	171	3.0	14,003	0.2	0.1	1.3	14,041	12,742
2022	14	14	62	172	194	184	3.3	15,080	0.2	0.1	1.4	15,122	13,722
2023	15	15	66	185	208	197	3.5	16,157	0.2	0.1	1.5	16,202	14,702
2024	16	16	71	197	222	210	3.7	17,234	0.2	0.1	1.6	17,282	15,682
2025	17	17	75	209	236	223	4.0	18,311	0.3	0.1	1.7	18,362	16,662
2026	18	18	79	221	250	236	4.2	19,388	0.3	0.2	1.8	19,442	17,642
2027	19	19	84	234	264	250	4.5	20,465	0.3	0.2	1.9	20,522	18,623
2028	20	20	88	246	278	263	4.7	21,542	0.3	0.2	2.0	21,602	19,603
2029	20	20	88	246	278	263	4.7	21,542	0.3	0.2	2.0	21,602	19,603
2030	20	20	88	246	278	263	4.7	21,542	0.3	0.2	2.0	21,602	19,603

Exhibit 5

THE POTENTIAL GREENHOUSE GAS EMISSIONS OF U.S. FEDERAL FOSSIL FUELS



The Potential Greenhouse Gas Emissions of U.S. Federal Fossil Fuels

August 2015

*Prepared for
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Friends of the Earth*

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The Potential Greenhouse Gas Emissions of U.S. Federal Fossil Fuels

I. Executive Summary

This report was undertaken to facilitate a better understanding of the consequences of future federal fossil fuel leasing and extraction in the context of domestic and global efforts to avoid dangerous climate change. We estimate the potential greenhouse gas (GHG) emissions from developing the remaining fossil fuels in the United States (U.S.), including the emissions from developing publicly owned, unleased federal fossil fuels that constitute 450 billion tons of CO₂e.

We report the volume of these fossil fuels, including that of leased and unleased federal fossil fuels located beneath federal and non-federal lands and the outer continental shelf. These resource appraisals are used to estimate the life-cycle GHG emissions associated with developing crude oil, coal, natural gas, tar sands, and oil shale—including emissions from extraction, processing, transportation, and combustion or other end uses. We express potential emissions in gigatons (“Gt”) (one gigaton equals one billion tons) of carbon dioxide equivalent (CO₂e), and discuss them below in the context of global emissions limits and nation-specific emissions quotas.

Major findings are that:

- The potential GHG emissions of federal fossil fuels (leased and unleased) are 349 to 492 Gt CO₂e, representing 46% to 50% of potential emissions from all remaining U.S. fossil fuels. Federal fossil fuels that have not yet been leased for development contain up to 450 Gt CO₂e.
- Unleased federal fossil fuels comprise 91% of the potential GHG emissions of all federal fossil fuels. The potential GHG emissions of unleased federal fossil fuel resources range from 319-450 Gt CO₂e. Leased federal fossil fuels represent from 30-43 Gt CO₂e.
- The potential emissions from unleased federal fossil fuels are incompatible with any U.S. share of global carbon limits that would keep emissions below scientifically advised levels.

Potential GHG Emissions from U.S. Federal Fossil Fuels

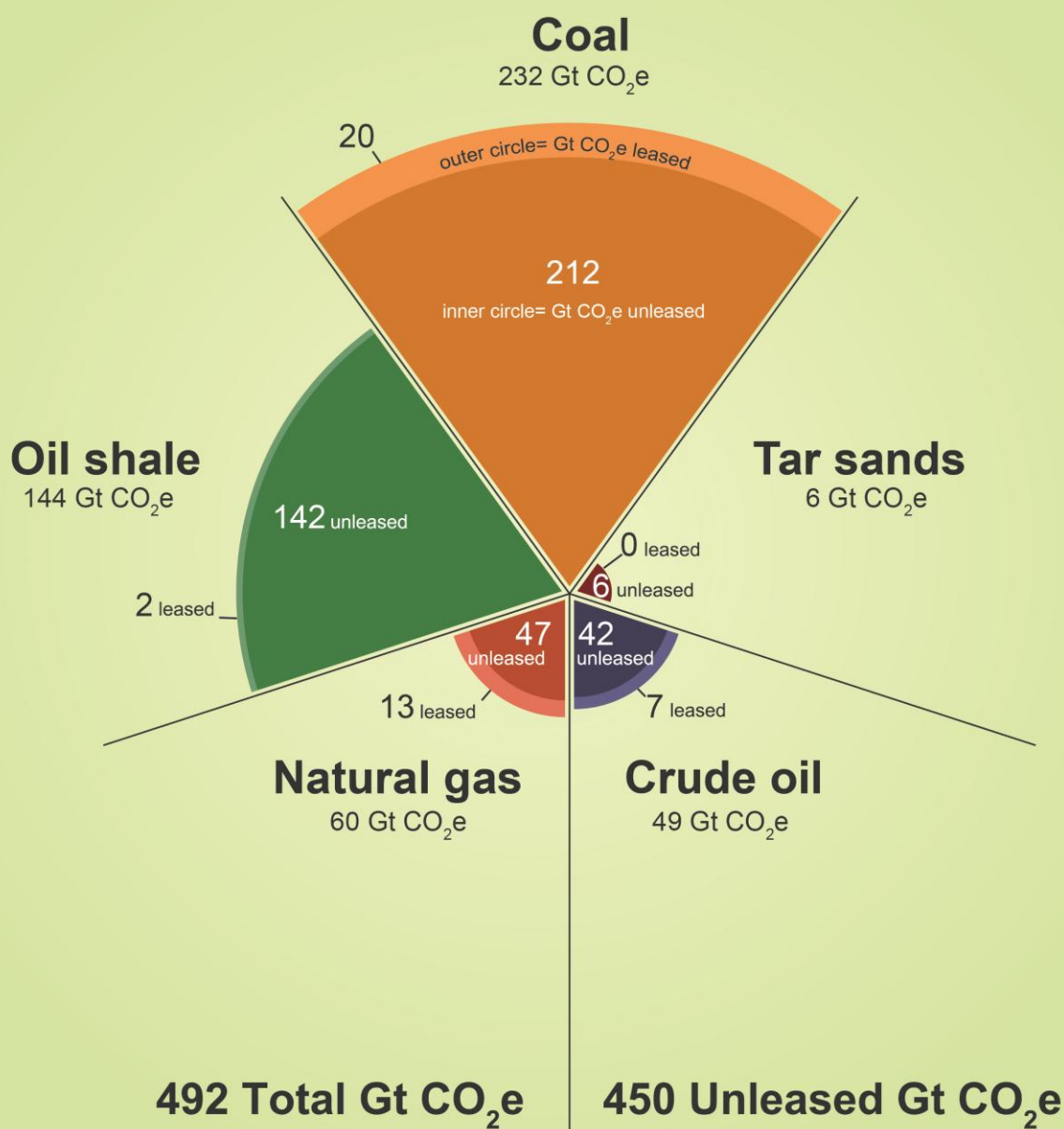


Figure 1. Potential emissions of leased and unleased federal fossil fuels.

Our results indicate that a cessation of new federal fossil fuel leasing could keep up to 450 Gt CO₂e from the global pool of potential future GHG emissions. (Figure 1.) This is equivalent to 13 times global carbon emissions in 2014 or annual emissions from

118,000 coal-fired power plants. This has a significant potential for GHG emissions savings that is best understood in the context of global limits and national emissions quotas.

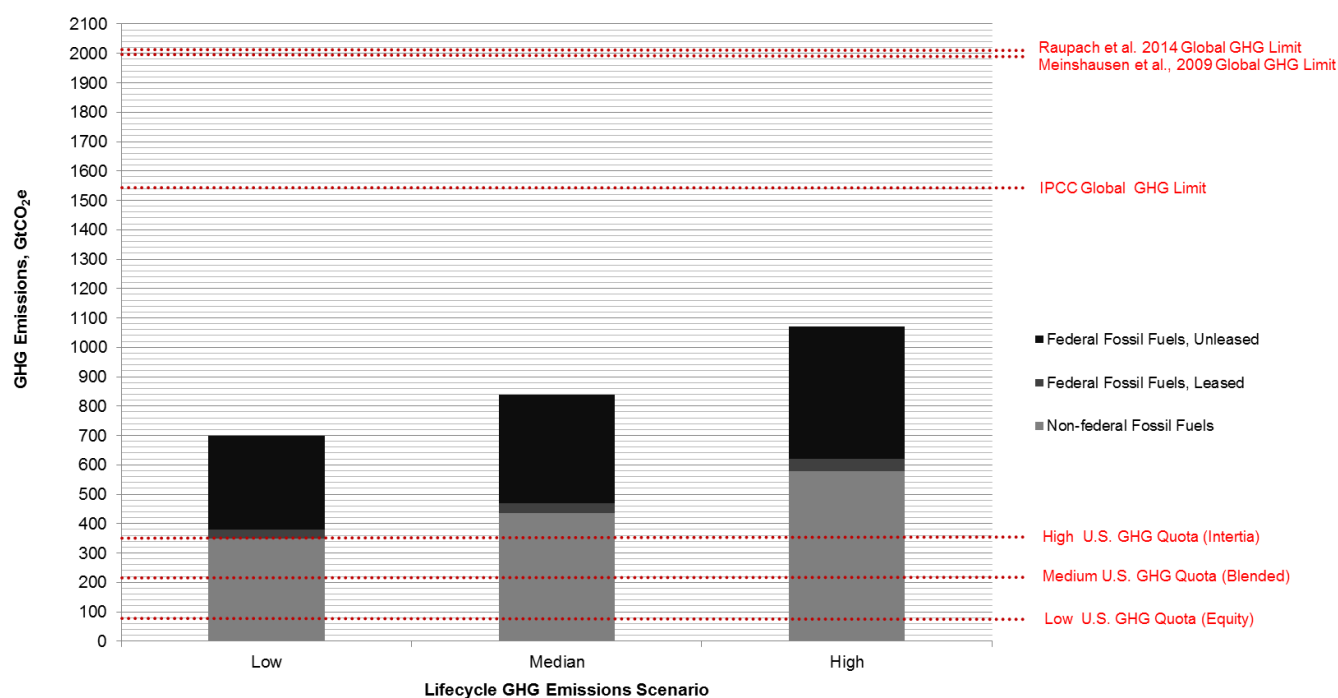
Carbon emission quotas are the maximum amount of greenhouse gases humanity can emit while still preserving a given chance of limiting average global temperature rise to a level that will not be catastrophic. The Intergovernmental Panel on Climate Change has recommended efforts to ensure that temperature increases remain below 2°C by century's end, a level at which dramatic adverse climate impacts are still expected to occur. Nation-specific emissions quotas are the amount of greenhouse gas emissions that an individual country can emitⁱ.

Studies that have apportioned global emissions quotas among the world's countries indicate that the U.S. share of the global emissions is limited, with varying estimates depending on the equity principles used. For example, Raupach et al. (2014) estimated three U.S. GHG emissions quota scenarios of 85Gt CO₂e, 220 Gt CO₂e, and 356 Gt CO₂e necessary to maintain only a 50 percent likelihood of avoiding 2°C (3.6°F) warming by century's end, depending on the equity assumptions used within a total global emissions limit. These represent a range of approximate equity assumptions for apportioning emissions quotas.ⁱⁱ Under any of those quotas, emissions from new federal fossil fuel leasing are precluded after factoring in the emissions of developing non-federal and already leased fossil fuels. (Figure 2.)

ⁱ In this report we use the terms "share of limit" and "quota" interchangeably and define them in the context of scientifically advised emission limitations exclusive of sequestration. In some cases, studies and reports also use the term "budget". Much of the literature, coverage, and usage of these issues utilize the terms in this way; however, in some cases carbon "budgets" are defined more broadly to encompass sources, fluxes and sinks; while "quotas" are defined more narrowly to encompass only limits on future emissions necessary to meet a certain average global temperature target. We feel this usage is appropriate here since "carbon budgets" generally refer to the total cumulative mass of carbon emissions allowable over time, while this report describes the total cumulative mass of carbon under federal and non-federal lands which may or may not be emitted into the atmosphere over time.

ⁱⁱ We use Raupach et al. (2014) U.S. emissions quotas for illustration purposes only; this report and its authors do not endorse equity assumptions made therein. We use the ratio of 1.39 CO₂e/CO₂ reported in Meinshausen et al. (2009) to convert the values reported in Raupach et al. (2014) from CO₂ to CO₂e. We also exclude Raupach et al.'s "future committed emissions" from their published -30, 67 and 165 GtCO₂ U.S. quotas to isolate the quotas from assumptions about "future committed emissions." Notably, under Raupach et al.'s "equity" scenario, "future committed emissions" already exceed the remaining U.S. quota; Raupach et al. thus report a remaining "equity" scenario quota of -30 Gt CO₂.

Potential Lifecycle GHG Emissions of Federal and Non-federal Fossil Fuels, and Global GHG Limits and U.S. GHG Quotas to Maintain 50% Likelihood of Keeping Warming Below 2°C (3.6°F) *



* GHG limits and quotas published in CO₂ are displayed in CO₂e using the ratio of 1.39 CO₂e/CO₂ reported in Meinshausen et al. (2009). U.S. GHG quotas from Raupach et al. 2014. Limits and quotas are lower for maintaining higher likelihood of limiting warming to below 2°C and/or keeping warming below a lower temperature, like 1.5°C.

Figure 2. Global carbon limits, U.S. emissions quotas and potential emissions from federal and non-federal fossil fuels.

II. Introduction

The Intergovernmental Panel on Climate Change (IPCC) recently warned that humanity must adhere to a strict “carbon limit” in order to preserve a likely chance of holding average global warming to less than 2°C (3.6°F) by the end of the century—a level of warming that still will cause extreme disruption to both human communities and natural ecosystems.¹ According to the IPCC, all future global emissions must be limited to about 1,000 gigatons (“Gt,” one gigaton equals one billion tons) of carbon dioxide (CO₂) to have a likely (>66%) chance of staying below 2°C.² The International Energy Agency has projected that the entire remaining 1,000 Gt CO₂ (1,390 Gt CO₂eⁱⁱⁱ) carbon budget will be consumed by 2040 on the current emissions course.³

Carbon quotas are the maximum amount of greenhouse gases humanity can emit while still preserving a given chance of limiting average global temperature rise to a level that will not be catastrophic. The Intergovernmental Panel on Climate Change has used a carbon limit to keep temperature increases below 2°C by century’s end, a level at which dramatic adverse climate impacts are still expected to occur. Nation-specific emissions

quotas are the amount of greenhouse gas emissions that an individual country can emit.^{iv}

Studies that have apportioned global emissions quotas among the world's countries indicate that the U.S. share of the global emissions is limited, with varying estimates depending on the equity principles used. For example, Raupach et al. (2014) estimated three U.S. GHG emissions quota scenarios of 85 Gt CO₂e, 220 Gt CO₂e, and 356 Gt CO₂e necessary to maintain only a 50 percent likelihood of avoiding 2°C (3.6°F) warming by century's end, depending on the equity assumptions used within a total global emissions limit. These represent a range of approximate equity assumptions for apportioning emissions quotas.^v Under any of those quotas, emissions from new federal fossil fuel leasing are precluded given the potential emissions from already-leased federal fossil fuels and those of non-federal fossil fuels.

Raupach et al.'s three scenarios are based on:

- High (inertia): Favors “grandfathering” of emissions, favoring a distribution of quota emissions to nations or regions with higher historical emissions.
- Medium (blended): Blends “inertia” and “equity” emissions.
- Low (equity): Favors a distribution of quota emissions based on population distribution, or emissions per capita, in regions or nations.

In 2013, the U.S. emitted 6.67 Gt CO₂e,⁴ the majority (85%) coming from the burning of fossil fuels,⁵ and accounting for 15% of global emissions.⁶ A 2015 analysis by an international team of climate experts⁷ suggests that for a likely probability of limiting warming to 2°C, the U.S. must reduce its GHG emissions in 2025 by 68 to 106% below 1990 levels, with the range of reductions depending on the sharing principles used.⁸ Accordingly, U.S. GHG annual emissions in 2025 would have to range between 2 Gt CO₂e (i.e., 68% below 1990) and negative emissions of -0.4 Gt CO₂e (i.e., 106% below 1990), significantly below current emissions of ~6.7 Gt CO₂e. Where negative emissions are required, the remaining carbon budget has been exhausted.

Under the current U.S. “all of the above” energy policy, federal agencies lease lands to private companies to extract and sell federal fossil fuel resources, including submerged offshore lands of the outer continental shelf. Leases initially last ten years, or twenty

^{iv} Emissions quotas are one among many mechanisms for determining equity and fairness in international climate negotiations. Equity principles generally include assumptions about different countries' historical responsibility for climate emissions, their ability to mitigate emissions, as well as measures of developed country support for emissions mitigation and adaptation in developing countries. While we are only using emissions quotas to illustrate the size of U.S. fossil fuel resources, we recognize that emissions quotas cannot be discussed independently from climate finance commitments.

^v We use Raupach et al. (2014) U.S. emissions quotas for illustration purposes only; this report and its authors do not endorse equity assumptions made therein. We use the ratio of 1.39 CO₂e/CO₂ reported in Meinshausen et al. (2009) to convert the values reported in Raupach et al. (2014) from CO₂ to CO₂e. We also exclude Raupach et al.'s “future committed emissions” from their published -30, 67 and 165 GtCO₂ U.S. quotas to isolate the quotas from assumptions about “future committed emissions.” Notably, under Raupach et al.'s “equity” scenario, “future committed emissions” already exceed the remaining U.S. quota; Raupach et al. thus report a remaining “equity” scenario quota of -30 Gt CO₂.

years in the case of coal, and may continue indefinitely once successful mineral extraction begins. Though these leases collectively span many tens of millions of acres, federal agencies do not currently track or report the nation-wide cumulative GHG emissions that result from federal leasing of fossil fuel reserves. There have been studies that account for past emissions from federal fossil fuel leasing. For example, a 2014 Stratus Consulting report completed for The Wilderness Society, titled *Greenhouse Gas Emissions from Fossil Energy Extracted from Federal Lands and Waters: An Update*, estimated that, in calendar year 2012, emissions from federal fossil fuel production were 1.344 Gt CO₂e, or 21% of all U.S. GHG emissions that year.⁹ A 2015 analysis completed by the Climate Accountability Institute for the Center for Biological Diversity and Friends of the Earth estimated that federal fossil fuel production accounted for 1.278 Gt CO₂e of emissions in 2012, and during the past decade contributed approximately 25% of all U.S. GHG emissions associated with fossil fuel consumption, which represents around 3-4% of global fossil fuel emissions during that time.¹⁰ Yet, there has been no assessment of the potential GHG savings from sequestering remaining unleased federal fossil fuels.

This report models the total amounts and potential GHG emissions associated with the remaining federal and non-federal fossil fuels in the U.S. We compiled federal and industry inventories of total fossil fuel resources and, using standard life-cycle assessment guidelines, we calculated life-cycle GHG emissions associated with all phases of developing federal and non-federal coal, crude oil, natural gas, tar sands, and oil shale resources. We evaluated low, median, and high emission scenarios for each of the fossil fuels studied to account for some of the uncertainties associated with producing some fossil fuels.

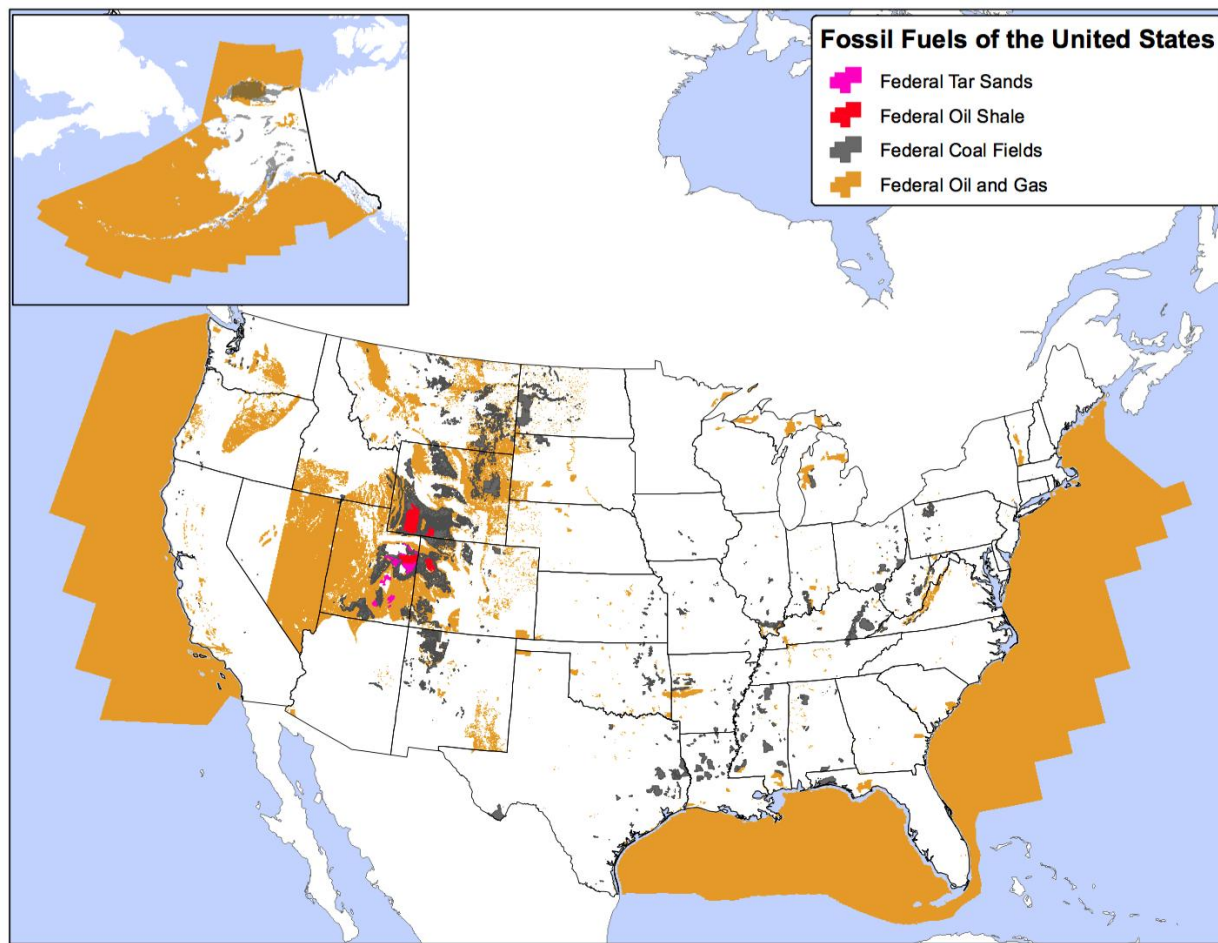


Figure 3. Map of U.S. Federal Fossil Fuels.

Our analysis focuses on the potential GHG emissions from the remaining unleased federal fossil fuel resources in the U.S. Keeping these fossil fuels in the ground would contribute significantly to global efforts to prevent combustion emissions from remaining fossil fuel resources. For the purposes of this report, unleased federal fossil fuels are those federal fossil fuel resources that are not currently leased to private companies. They include unleased recoverable federal coal reserves, federal oil shale, federal crude oil, federal natural gas, and federal tar sands. Unleased federal fossil fuels include resources that are available for leasing under current federal policy and that could become available for leasing under future federal policy.¹¹

Key terms

All U.S. fossil fuels include all federal and non-federal recoverable coal reserves, oil shale, crude oil, natural gas and tar sands (onshore and offshore).

Federal fossil fuels are federally controlled, publicly owned fossil fuel resources. Federal fossil fuels are located beneath lands under federal and other ownerships, where the federal government owns subsurface mineral rights. They are also located “offshore,” beneath submerged public lands of the outer continental shelf. Federal fossil fuels include recoverable federal coal reserves, federal oil shale, federal crude oil, federal natural gas and unleased federal tar sands.

Leased federal fossil fuels are federal fossil fuel resources, including proved reserves and resources under non-producing leased land, as classified by the Bureau of Ocean Energy Management (BOEM) and Bureau of Land Management (BLM), which are currently leased to private companies. These include leased federal recoverable coal reserves, leased federal oil shale, leased federal crude oil, leased federal natural gas and leased federal tar sands.

Non-federal fossil fuels are fossil fuel resources calculated by subtracting federal fossil fuel amounts from total technically recoverable oil resources, total technically recoverable natural gas resources, and total recoverable coal reserves in the United States as provided by EIA 2012a.

Unleased federal fossil fuels are federal fossil fuel resources that are not leased to private companies. These include unleased recoverable federal coal reserves, unleased federal oil shale, unleased federal crude oil, unleased federal natural gas, and unleased federal tar sands.

Recoverable coal reserves are the portion of the Demonstrated Reserve Base that the Energy Information Agency estimates may be available or accessible for mining.

Federal recoverable coal reserves are the federally controlled portion of recoverable coal reserves.

Crude oil is onshore and offshore technically recoverable federal and non-federal crude oil resources. **Federal crude oil** is federally controlled crude oil.

Natural gas is onshore and offshore technically recoverable federal and non-federal natural gas resources. **Federal natural gas** is federally controlled natural gas.

Federal oil shale is federally controlled oil shale that is geologically prospective according to deposit grade and thickness criteria in the Bureau of Land Management’s 2012 Final Oil Shale and Tar Sands Programmatic Environmental Impact Statement (PEIS) and Record of Decision (ROD). Geologically prospective oil shale resources in

Colorado and Utah are deposits that yield 25 gallons of oil per ton of rock (gal/ton) or more and are 25 feet thick or greater. In Wyoming geologically prospective resources are deposits that yield 15 gal/ton or more and are 15 feet thick or greater.

Tar sands are estimated in-place tar sands resources. **Federal tar sands** are federally controlled tar sands.

Proved or proven reserves are estimated volumes of hydrocarbon resources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions. Reserve estimates change from year to year as new discoveries are made, existing fields are more thoroughly appraised, existing reserves are produced, and prices and technologies change. Because establishing proved reserves requires drilling, which first requires leasing, proved federal fossil fuel reserves are necessarily leased, and unleased federal fossil fuels necessarily are not proved.

Technically recoverable refers to oil and gas resources that are unleased but producible using current technology without reference to their economic viability.

In-place resource is the entire fossil fuel resource in a geologic formation regardless of its recoverability or economic viability.

II. Research Methodology

Greenhouse gas (GHG) emissions associated with developing fossil fuel resources were estimated by (a) quantifying the volume and energy value of federal and non-federal fossil fuels, (b) determining the end uses and proportions of different end-use products made from fossil fuels, and (c) estimating the total GHG emissions from developing these resources and processing them into end-use products, by multiplying the total volume energy value of fossil fuel products by their life-cycle emissions factors.



Figure 4. Research methodology

A) Quantifying Fossil Fuel Resources Volumes and Energy Values

Federal and non-federal fossil fuel quantities were obtained from federal estimates by the Bureau of Land Management (BLM), Energy Information Agency (EIA), U.S. Geological Survey (USGS), Office of Natural Resource Revenue (ONRR), the Department of Interior (DOI), and Congressional Research Service (CRS). Federal agencies similarly report the technically recoverable resources for crude oil and natural gas based on a consistent definition. For coal, agencies estimate recoverable coal by assessing the accessibility and recovery rates for the demonstrated coal base. For oil shale and tar sands the quantity is based on the resource available and in-place resources, which do not attempt to characterize the resource based on the likelihood of development. Unleased volumes of federal fossil fuels were calculated by subtracting leased volumes from the sum of technically recoverable quantities.

Quantities of federal and non-federal crude oil, natural gas, coal, oil shale and tar sands were summed and converted into values that represent each fossil fuel's energy content, called its primary energy value. This was done by multiplying the fossil fuel volumes by a heating value factor that represents the resource's energy content. Lower Heating Values were used for all fuels except coal, where the Higher Heating Value was taken as per convention for solid fuels in the U.S. Heating values for each resource were taken from Oak Ridge National Laboratory (ORNL), and can be found in the *Fossil Fuel Volumes to Primary Energy Conversions* section in Appendix I.

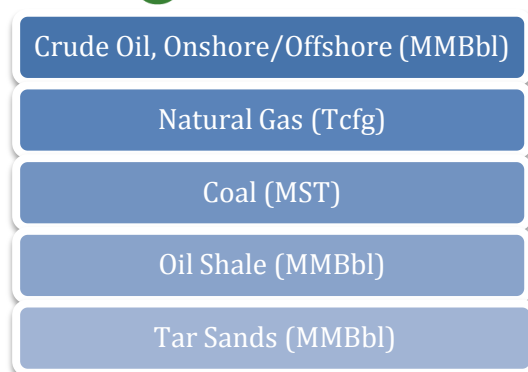


Figure 5. Fossil fuels analyzed

Figure 3 above shows the five fossil fuel types analyzed as they are broadly defined by federal agencies: Oil (onshore and offshore), gas (onshore and offshore) coal, oil shale and tar sands. The hydrocarbons included within federal oil and gas definitions are reported in Table 1 below.

Fossil fuel type	Crude oil	Condensate	Natural gas liquids	Dry natural gas	Gas, wet after lease separation	Non-associated gas, wet after separation	Natural gas associated-dissolved, wet after lease separation	Coalbed methane
Onshore oil	x	X	x					
Offshore oil	x	X	x					
Onshore gas				x	x	x	x	x
Offshore gas				x	x	x	x	x

Table 1. Hydrocarbons in the categories of crude oil and natural gas

B) Determining the End-Use Products Made from Fossil Fuels

Each fossil fuel resource was converted to a value that represents its energy content and divided into amounts used as inputs for different end-use products. We allocated the proportions of each resource into end-use products as follows:

- The energy in crude oil resources was proportionally divided into: finished motor gasoline, distillate fuel oil, kerosene, liquefied petroleum gases (LPG), petroleum coke, still gas and residual fuel oil.
- The energy in natural gas resources was split into residential, commercial, industrial, electric power and transportation end-use sectors.
- The energy in coal reserves was divided to electric power, coke and other industrial uses.
- Energy in tar sands and oil shale was assumed to be processed into end-use products analogous to crude oil.

These proportions make it possible to apply end-use product specific life-cycle emissions factors. For each product we determined the amount that could be yielded from the initial energy after processing, using a “primary energy factor” derived from

figures and conversion factors from sources in the literature, such as those developed at the National Renewable Energy Laboratory (NREL).

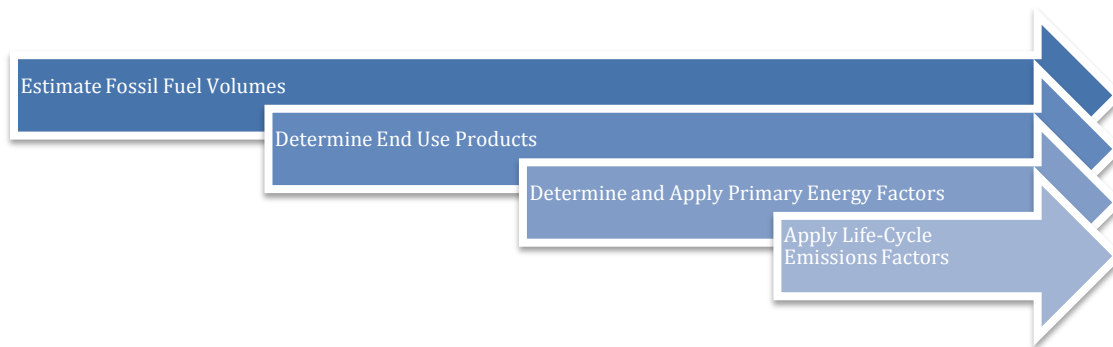


Figure 6. Steps to determine fossil fuel amounts and apply specific energy and emissions factors

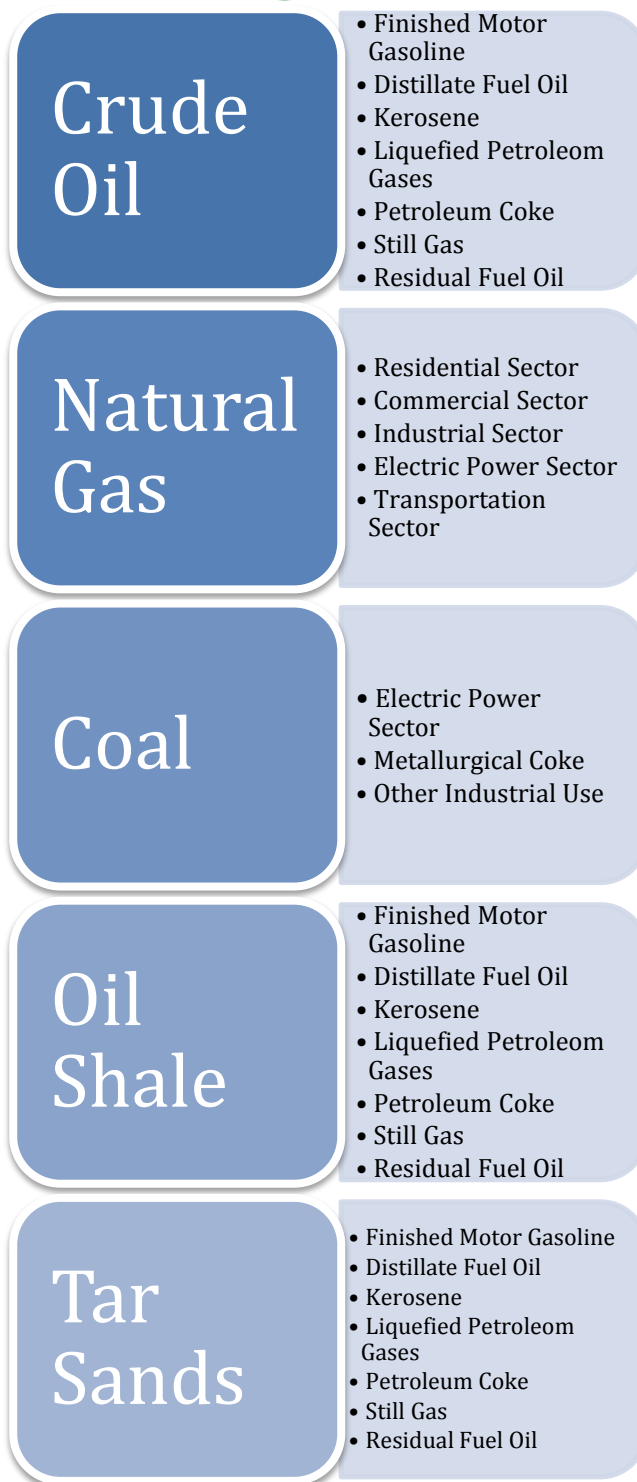


Figure 7. Fossil fuel resources and end-use products and sectors

C) Multiplying the Quantity of Fossil Fuel Energy by GHG Emissions Factors

The total energy value of each fossil fuel product end use was multiplied by product-specific life-cycle emissions factors to estimate the total GHG emissions. Life-cycle GHG emissions factors represent the amount of GHGs released when burning one unit 15

of energy. In peer-reviewed life-cycle assessments of fossil fuels, there are uncertainties associated with the GHG emissions of some fuels. For example, the life-cycle emissions associated with land use change resulting from coal extraction can be a source of uncertainty given differing amounts of methane leakage. To account for these uncertainties, the analysis used three scenarios for each fossil fuel corresponding to high, median, low GHG emissions factors reported in the scientific literature. The low GHG emissions factor scenario was chosen as the base case, and the high emissions factor scenario is the worst case scenario (most inefficient use of fossil fuels).

Each scenario represents different magnitudes (high, median and low) of global warming pollution associated with different fossil fuels. The high emissions scenario represents the worst-case greenhouse gas pollution scenario. Where available we used emissions factors from research by the U.S. national energy laboratories including Argonne National Laboratories' GREET tool and several meta-analyses from NREL that produced harmonized emissions-factors based on extensive prior research. Although emissions factors can vary following changes in any of the parameters in the underlying study, Table 2 in Appendix II highlights key parameters that significantly affect the magnitude of the emission factor and consequently influence whether it is characterized as low, median or high.

Where necessary, the following end-use product specific adjustments were made to improve the accuracy of life-cycle emissions factors:

- A carbon storage factor was determined for the following end-use products: metallurgical coke from coal, distillate fuel, liquefied petroleum gases (LPGs), petroleum coke from crude oil, and still gas.¹² This is to account for a proportion of carbon in the fossil fuel resource that is stored in the end product and not combusted or otherwise emitted. For example, some of the carbon in petroleum coke remains in products such as urea and silicon carbide, and the carbon storage factor reflects this.
- A shale-play weighting factor was applied to calculate emissions from natural gas to account for some studies that suggest that there may be higher amounts of methane released with natural gas extracted from shale versus conventional resources.¹³
- These calculations were summed to present results in 100-year Global Warming Potentials, represented as gigatons CO₂ equivalent (Gt CO₂e).

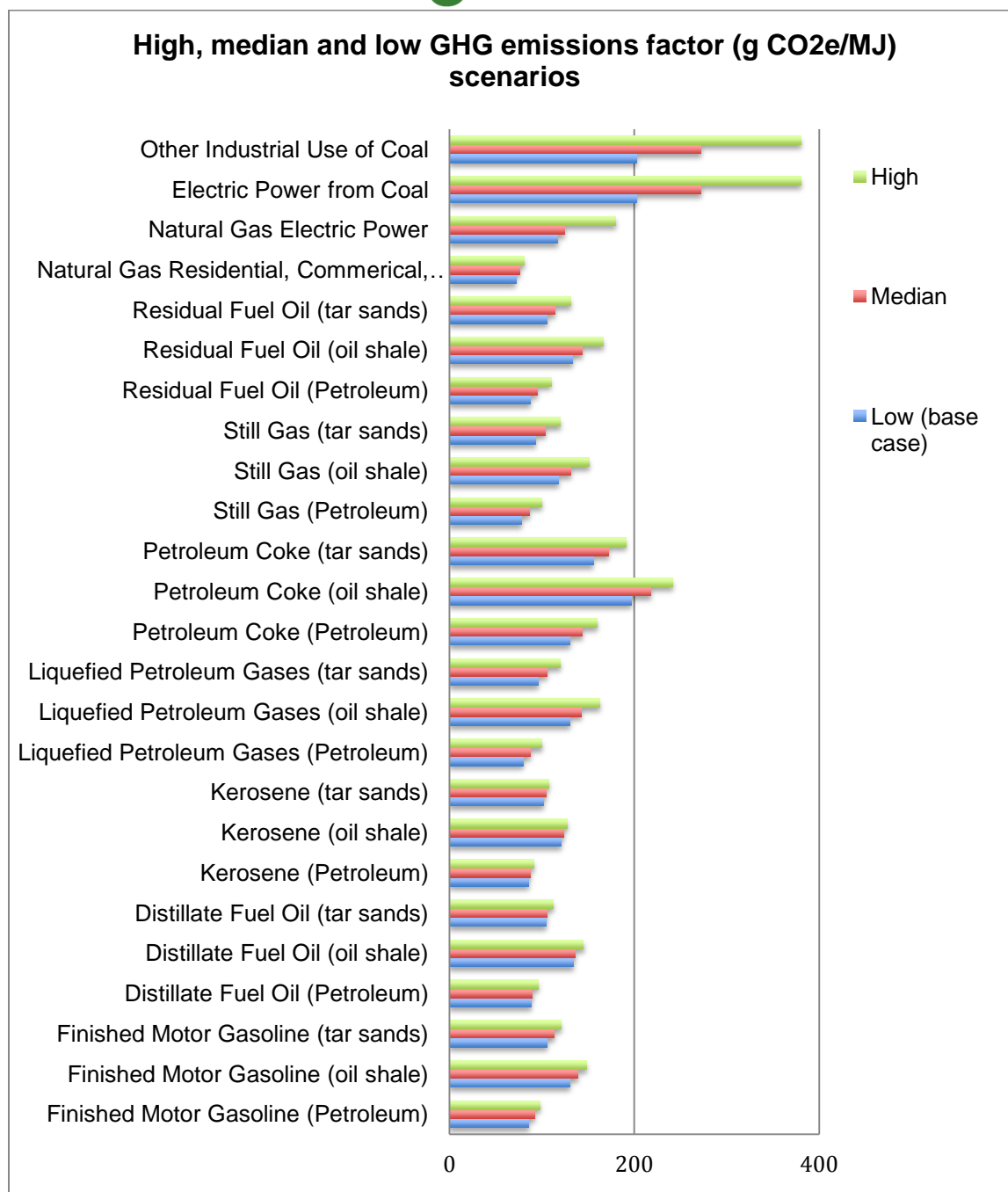


Figure 8. High, median and low (base case) GHG emissions factor scenarios.

Appendix I provides detailed methodologies for estimating fossil fuel volumes, converting fossil fuel volumes to primary energy, and calculating resource and end-use product-specific life-cycle emission factors. The full list of sources used to estimate fossil fuel amounts, primary energy factors, proportions of end-use products and sectors, carbon storage factors, and product specific life-cycle emissions factors are available in Appendix II.

III. Results

Our results indicate that:

1. The potential GHG emissions federal fossil fuels, leased and unleased, are 348.96 to 492.22 Gt CO₂e, representing 46% to 50% of potential emissions from all remaining U.S. fossil fuels; The potential GHG emissions of federal and non-federal fossil fuels are 697-1,070 Gt CO₂e.
Unleased federal fossil fuels comprise 91% of the potential GHG emissions of all federal fossil fuels. The potential GHG emissions of unleased federal fossil fuel resources range from 319.00 to 449.53 Gt CO₂e. Leased federal fossil fuels represent from 29.96 to 42.69 Gt CO₂e;
2. Unleased federal recoverable coal accounts for 36% to 43% of the potential GHG emissions of all remaining federal fossil fuels, from 115.32 to 212.26 Gt CO₂e. Leased federal recoverable coal represents from 10.68 to 19.66 Gt CO₂e of potential emissions.
3. Unleased federal oil shale accounts for 29% to 35% of potential GHG emissions of all remaining federal fossil fuels, ranging from 123.17 to 142.07 Gt CO₂e. Leased federal oil shale accounts for 0.3% to 0.6% of potential GHG emissions of all remaining federal fossil fuels, representing 2 Gt CO₂e;
4. Unleased federal natural gas accounts for 10% to 11% of potential GHG emissions of all remaining federal fossil fuels, ranging from 37.86 to 47.26 Gt CO₂e, of which 36% are onshore and 64% are offshore. Leased federal gas represents 10.39 to 12.88 Gt CO₂e, 47% of which are onshore and 53% are offshore.
5. Unleased federal crude oil accounts for 9% to 12% of potential GHG emissions of all remaining federal fossil fuels, ranging from 37.03 to 42.19 Gt CO₂e, of which 28% are onshore and 72% are offshore. Potential emissions from leased federal crude oil represents from 6.95 to 7.92 Gt CO₂e, of which 33% are onshore and 67% are offshore.
6. Unleased federal tar sands accounts for 1% to 2% of potential GHG emissions of all remaining federal fossil fuels, ranging from 5.62 to 5.75 Gt CO₂e.

Federal versus non-federal fossil fuels

The potential GHG emissions from federal and non-federal fossil fuels were compared to contextualize the proportion that is federally owned. The results indicate that 34% of all remaining fossil fuels, based on the energy content of those fuels, are federally owned; these represent 348.96 to 492.22 Gt CO₂e of potential GHG emissions.

Table 2. GHG emissions, in GtCO₂e, from federal and non-federal fossil fuels

	Low	Median	High
Federal Leased	29.96	34.65	42.69
Federal Unleased	319.00	369.98	449.53
Non-federal	348.49	435.14	577.78
Total	697.45	839.77	1,070.00

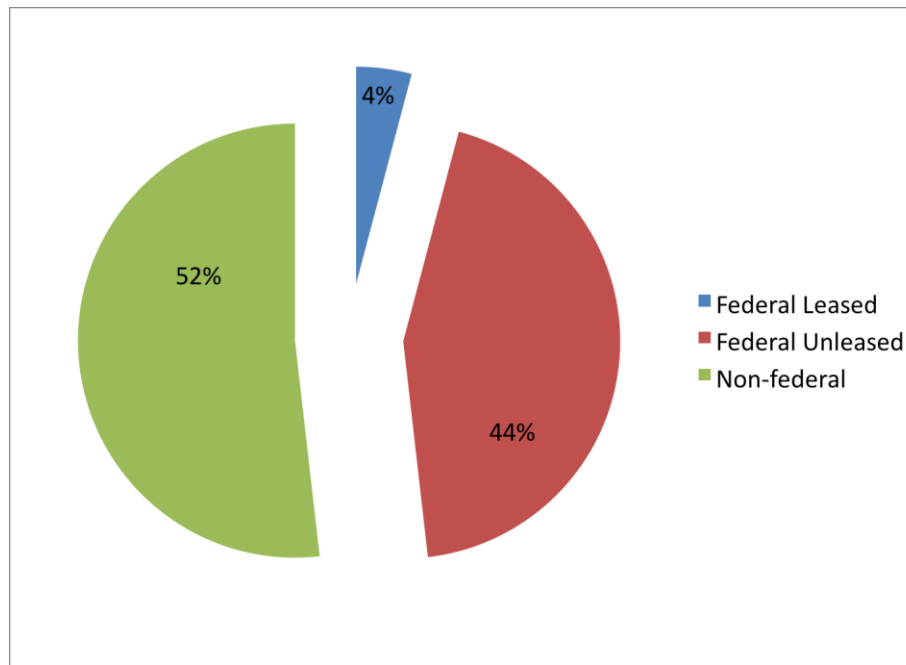


Figure 9. Relative potential emissions of federal and non-federal fossil fuels

Leased and unleased federal fossil fuels

Unleased and leased federal fossil fuels were examined to measure the GHG pollution from past leasing and to estimate the potential GHG emissions of unleased federal fossil fuels. Leased emissions are calculated using volumes of proved offshore and onshore oil and gas, volumes of offshore and onshore oil and gas underlying non-producing leased land, amounts of leased coal, and volumes of leased oil shale. The potential GHG emissions from unleased fossil fuel resources are approximately ten times greater than the emissions from currently leased federal fossil fuels.

Table 3. GHG Emissions (Gt CO₂e) from leased and unleased federal fossil fuels

	Low	Median	High
Federal Leased (Total)	29.96	34.65	42.69
<i>Crude Oil</i>	6.95	7.38	7.92
<i>Natural Gas</i>	10.39	11.01	12.88
<i>Coal</i>	10.68	14.19	19.66
<i>Oil Shale</i>	1.94	2.07	2.23
Federal Unleased (Total)	319.00	369.98	449.53
<i>Crude Oil</i>	37.03	39.32	42.19
<i>Natural Gas</i>	37.86	40.13	47.26

<i>Coal</i>	115.32	153.19	212.26
<i>Oil Shale</i>	123.17	131.67	142.07
<i>Tar Sands</i>	5.62	5.67	5.75

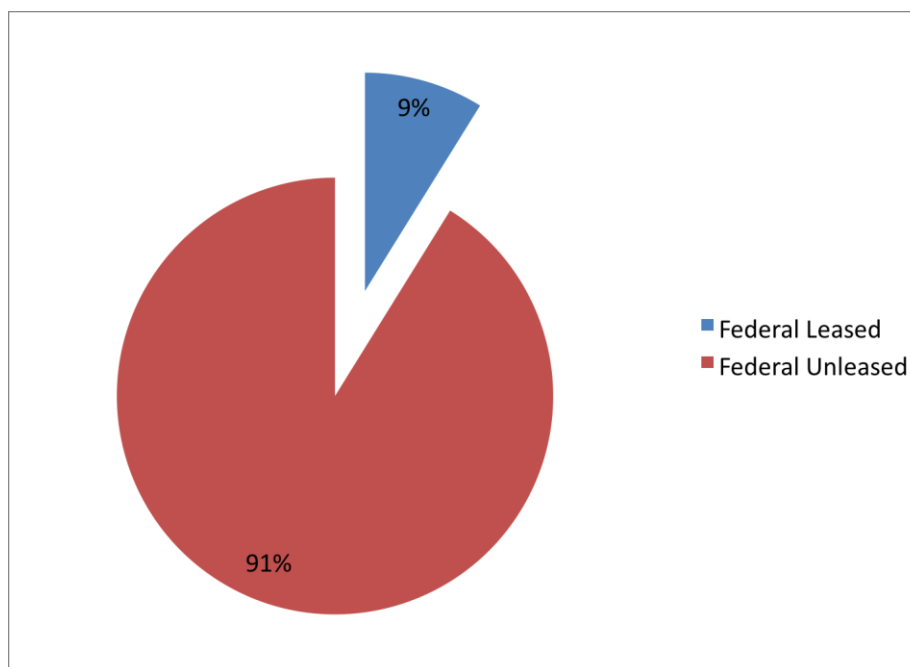


Figure 10. Low GHG emission factor scenario for leased and unleased federal fossil fuels

Unleased federal fossil fuels by resource type

The GHG emissions from unleased federal fossil fuels were evaluated by resource type. In a low emissions factor scenario, coal and oil shale are the biggest contributors of greenhouse gases. Under a high emissions factor scenario, coal is the biggest contributor of GHG pollution.

Table 4. GHG emissions (GtCO₂e) from unleased federal fossil fuels by resource type

	Low	Median	High
Federal Unleased			
<i>Crude Oil</i>	37.03	39.32	42.19
<i>Natural Gas</i>	37.86	40.13	47.26
<i>Coal</i>	115.32	153.19	212.26
<i>Oil Shale</i>	123.17	131.67	142.07
<i>Tar Sands</i>	5.62	5.67	5.75

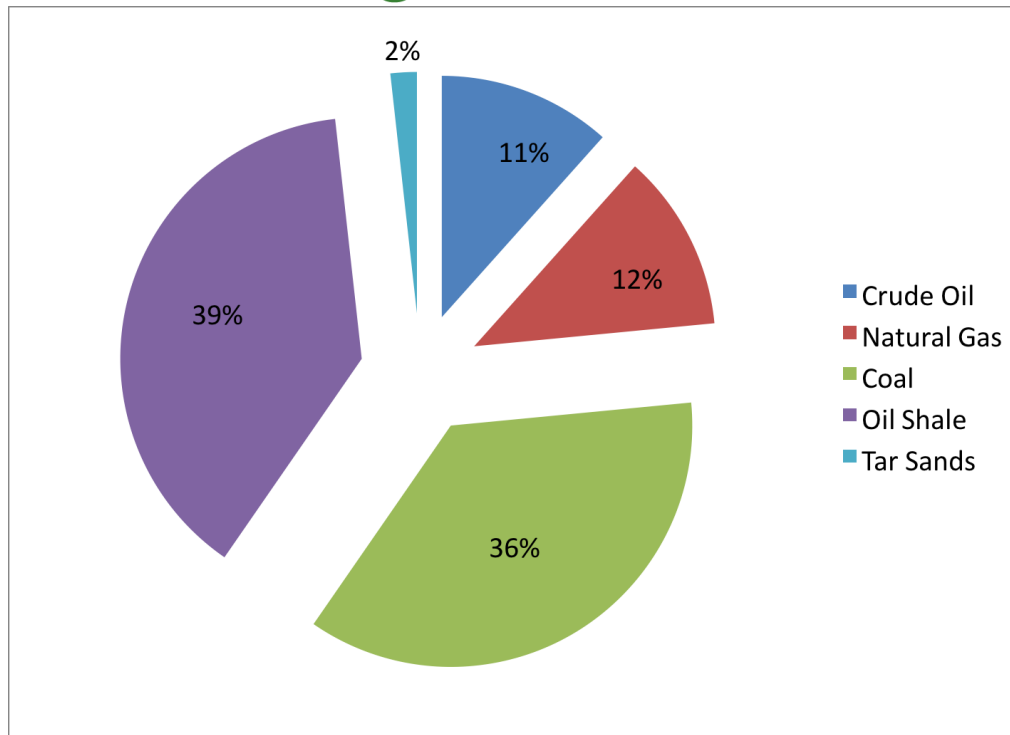


Figure 11. GHG emissions from unleased federal fossil fuels by resource type (low emissions scenario)

Coal

The potential greenhouse gas emissions from unleased recoverable coal reserves and leased recoverable coal reserves range from 115 to 212 Gt. This analysis used “recoverable coal reserves” when estimating the GHG emissions from coal, which is a common and conservative estimate of the portion of coal that could be extracted.

Table 5. GHG emissions (GtCO₂e) from federal coal

	Mass (MMST)	Low	Median	High
Federal Recoverable Coal Reserves				
<i>Unleased</i>	86,204	115.32	153.19	212.26
<i>Leased</i>	7,376	10.68	14.19	19.66

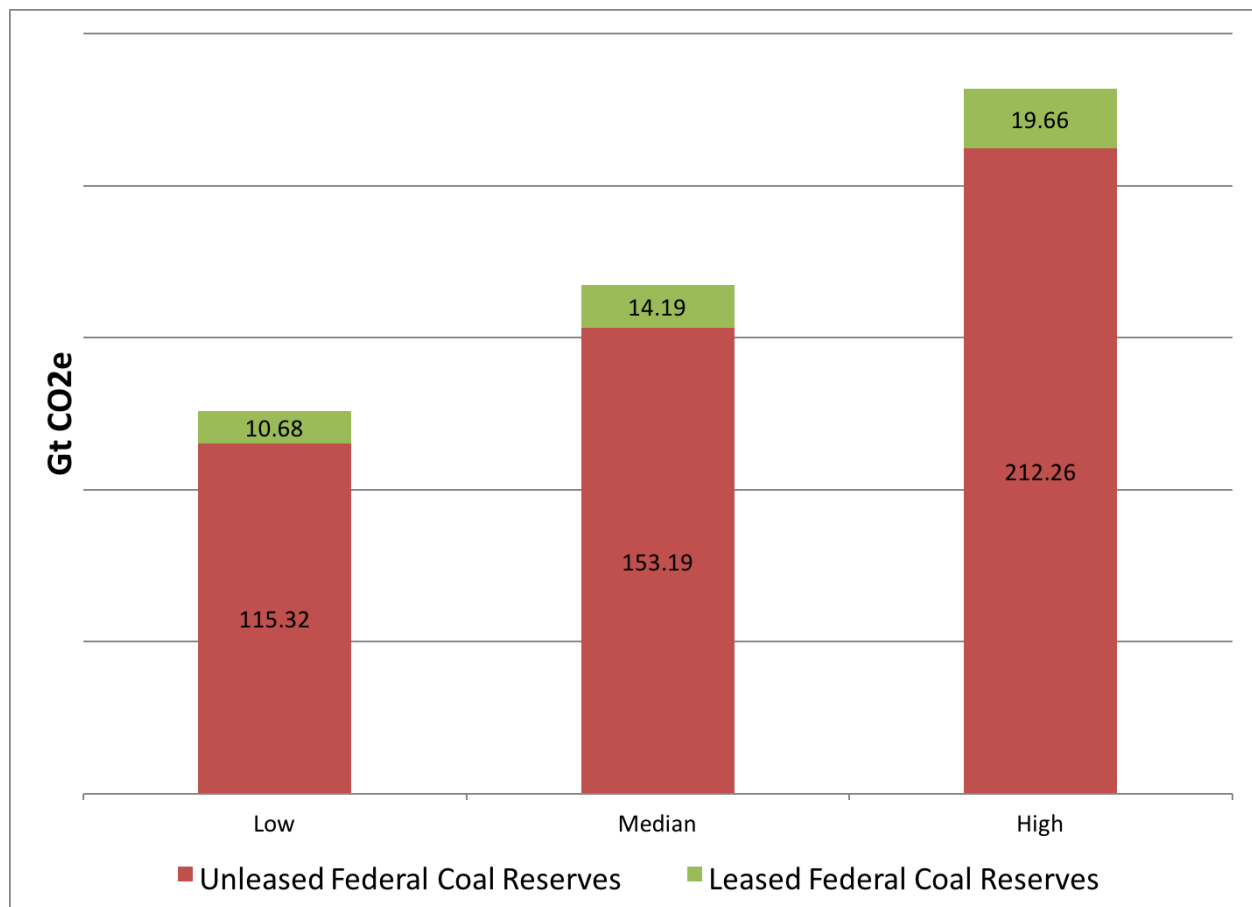


Figure 12. GHG emissions from federal coal under low, median and high emissions scenarios

Oil Shale

We analyzed the potential GHG emissions of federal oil shale and the portion of federal oil shale that is available for leasing under current federal policies. Since the life cycle GHG emissions of oil shale extraction and production are more than 50% greater than conventional crude oil per unit energy, oil shale resource results in the most potential GHG emissions per unit of energy delivered for all fossil fuels except coal. Federal oil shale includes only the resource that is geologically prospective according to deposit grade and thickness criteria in the Bureau of Land Management's (BLM) 2012 Final Oil Shale and Tar Sands Programmatic EIS and Record of Decision. Geologically prospective oil shale resources in Colorado and Utah are deposits that yield 25 gallons of shale oil per ton of rock (gal/ton) or more and are 25 feet thick or greater. In Wyoming geologically prospective resources are deposits that yield 15 gal/ton or more and are 15 feet thick or greater. Our analysis assumes that geologically prospective federal oil shale resources that are not currently available for leasing can potentially become available for leasing in the future because they are under federal mineral rights.

Table 6. GHG emissions (GtCO₂e) from federal geologically prospective oil shale

	Volume (MMBbls)	Low	Median	High
Federal Oil Shale				
<i>Available for Lease Under PEIS and ROD & RD&D Leases</i>	75,606	24.65	26.35	28.44
<i>Total in Place Resource</i>	383,678	123.17	131.67	142.07

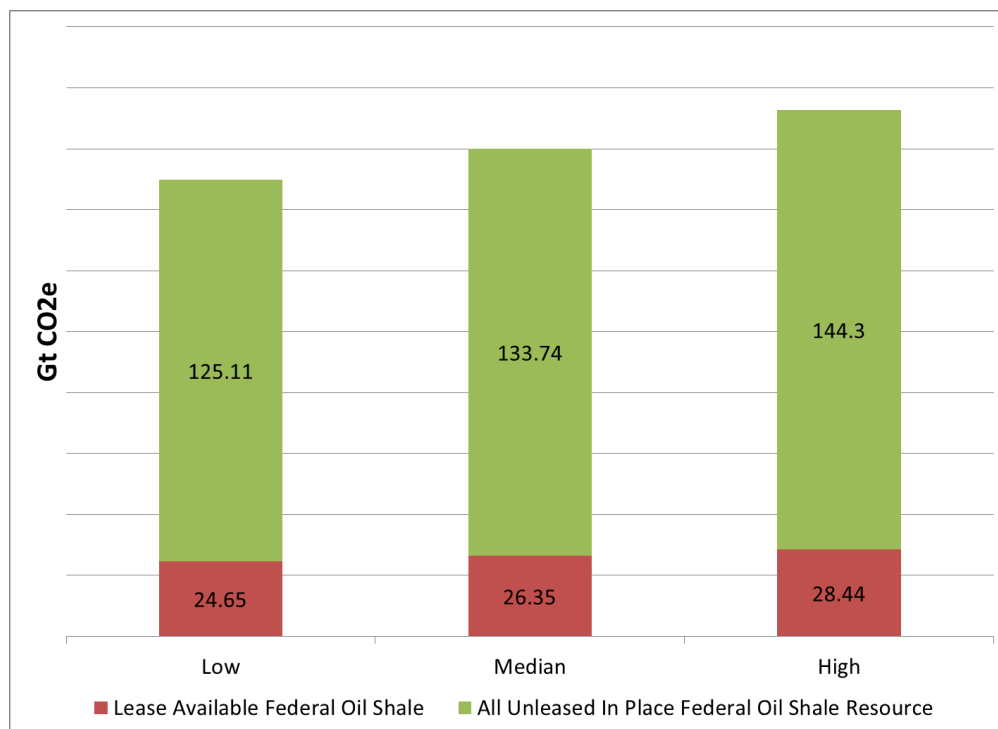


Figure 13. GHG emissions (Gt CO₂e) from federal oil shale under low, median and high emissions scenarios

Crude Oil

The potential GHG emissions of onshore and offshore federal crude oil range from 9.38 to 10.69 and 27.65 to 31.50 Gt CO₂e respectively. The potential GHG emissions of all federal crude oil range from 37.03 to 42.19 Gt CO₂e.

Table 7. GHG emissions (GtCO₂e) from federal crude oil

	Volume (MMBbls)	Low	Median	High
Unleased Federal Crude Oil				
<i>Onshore</i>	33,648	9.38	9.96	10.69
<i>Offshore</i>	74,649	27.65	29.36	31.50
<i>Total</i>	120,433	37.03	39.32	42.19

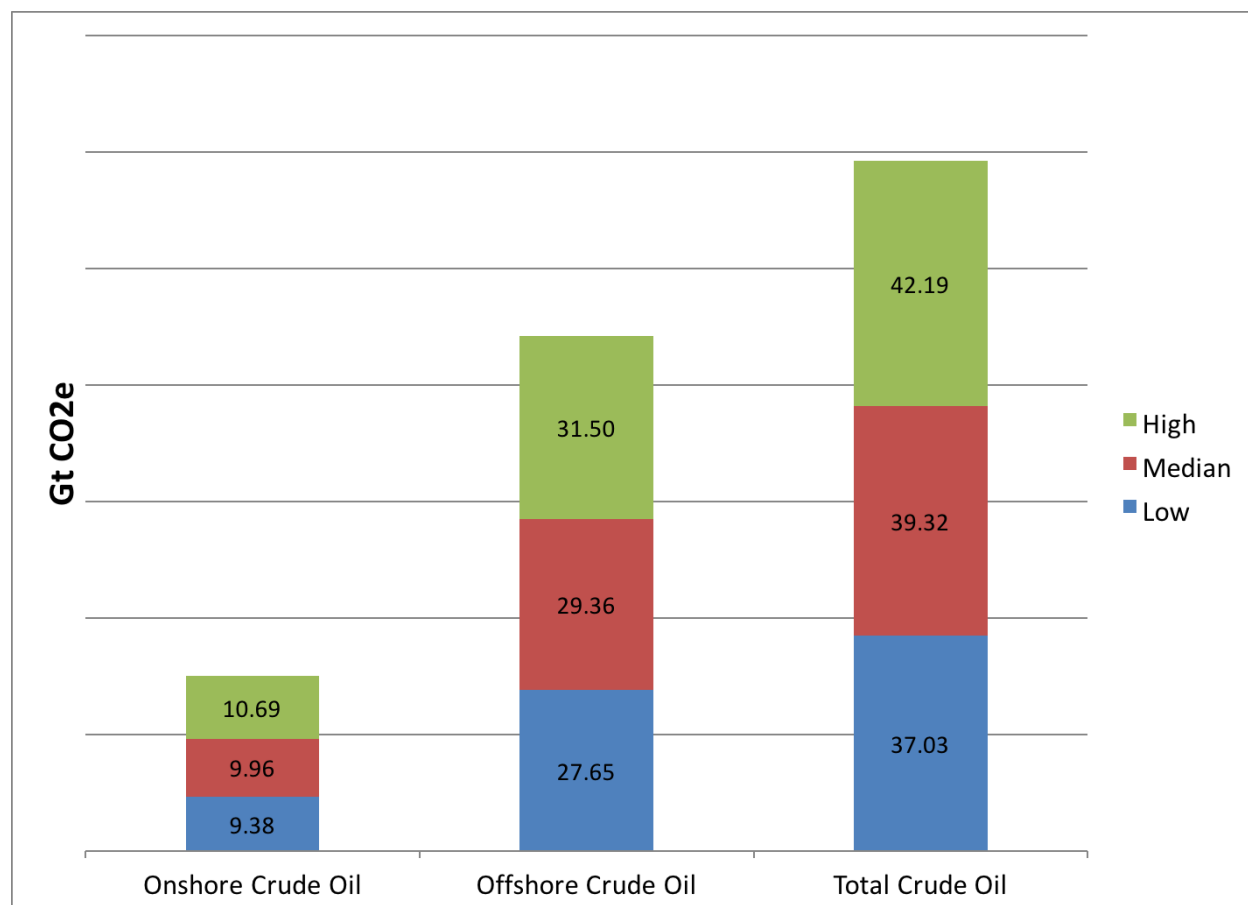


Figure 14. GHG emissions (GtCO₂e) from unleased federal crude oil

Natural Gas

Natural gas emissions were found to be 8–9% of total potential GHG emissions from federal fossil fuels.

Table 8. GHG emissions (GtCO₂e) from federal natural gas

	Volume (Tcfg)	Low	Median	High
Unleased Federal Natural Gas				
<i>Onshore</i>	231	13.79	14.61	17.21
<i>Offshore</i>	405	24.07	25.52	30.05
<i>Total</i>	635	37.86	40.13	47.26

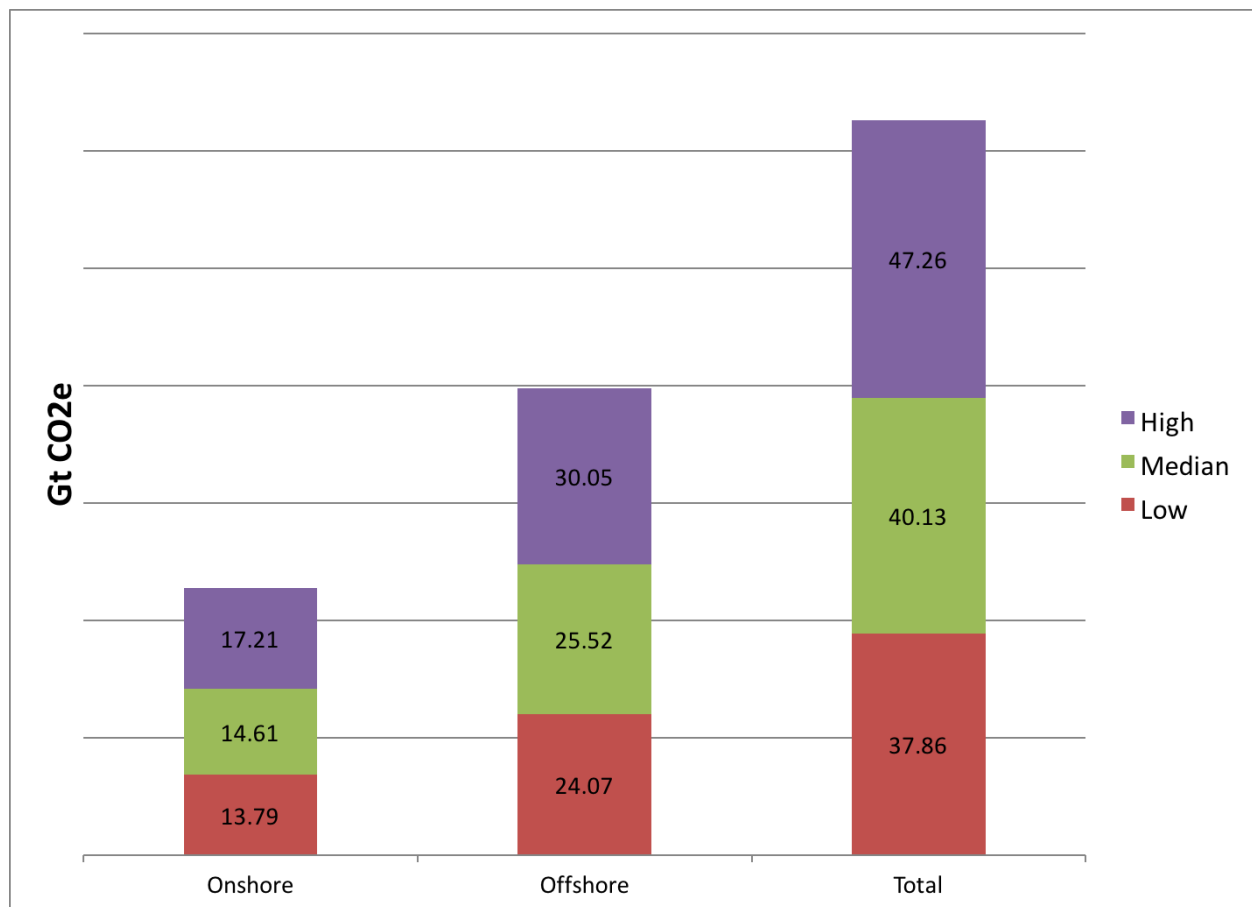


Figure 15. GHG emissions (GtCO₂e) from unleased federal natural gas

Tar Sands

Federal tar sands account for 1-2% of total potential GHG emissions from federal fossil fuels. However, it should be noted that the emissions per barrel of oil processed from tar₂₅

sands is significantly greater than that of crude oil per unit energy. Processing more tar sands into gasoline increases the GHG intensity of that fuel.

Table 9. GHG emissions (GtCO₂e) from federal tar sands

	Volume (MMBbls)	Low	Median	High
Federal Tar Sands				
<i>Lease Available</i>	4,125	1.40	1.41	1.43
<i>Total In Place Resource</i>	16,551	5.62	5.67	5.75

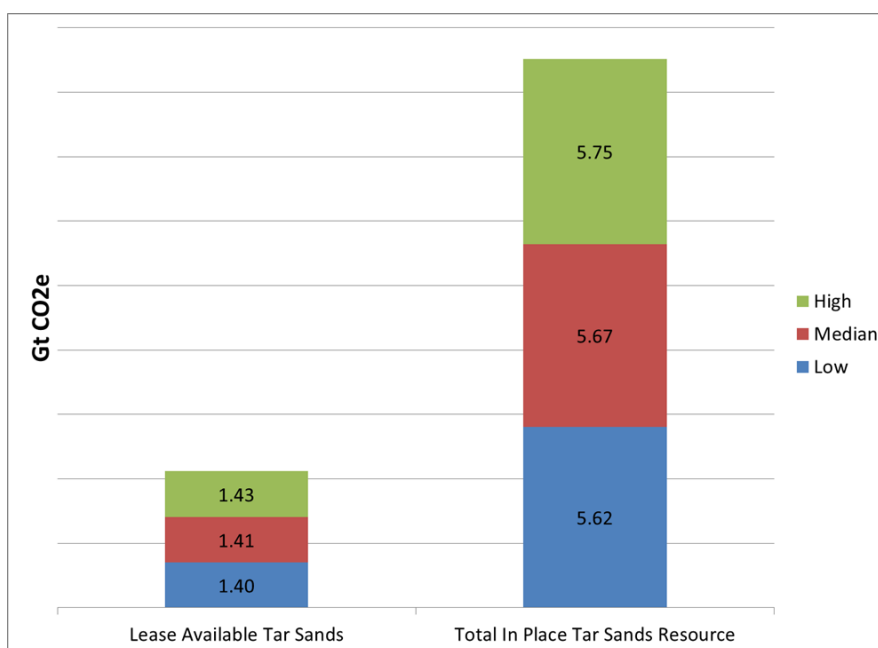


Figure 16. GHG emissions (GtCO₂e) from federal tar sands

IV. Conclusion

This report is the first to estimate the GHG emissions associated with developing federal and non-federal fossil fuels in the United States. Our results show the 100-year global warming potential of emissions resulting from the potential extraction, processing and combustion of fossil fuels under federal mineral rights. The potential GHG emissions savings associated with all federal fossil fuels, leased and unleased, is 349 to 492 GtCO₂e. Our results indicate that a cessation to new federal fossil fuel leasing could keep up to 450 Gt CO₂e from the global pool of potential future GHG emissions.

Studies that have apportioned global emissions quotas among the world's countries indicate that the U.S. share of the global emissions is limited, with varying estimates depending on the equity principles used. For example, Raupach et al. (2014) estimated three U.S. GHG emissions quota scenarios of 85 Gt CO₂e, 220 Gt CO₂e, and 356 Gt CO₂e necessary to maintain only a 50 percent likelihood of avoiding 2°C (3.6°F)

warming by century's end, depending on the equity assumptions used within a total global emissions limit. These represent a range of approximate equity assumptions for apportioning emissions quotas. Under any of those quotas, emissions from new federal fossil fuel leasing are precluded given the potential emissions from already-leased federal fossil fuels and those of non-federal fossil fuels.

Appendix I: Methodology

A1. Quantity of fossil fuels on federal lands

Determining the available fossil fuel volumes on federal lands is the starting point for analyzing the potential GHG emissions (see Appendix II: Table 1). Our approach classified fossil fuels into five broad categories: crude oil, natural gas, coal, oil shale and tar sands. We reviewed the resources used in prior research and determined that the most reliable sources for volumes of fossil fuels on federal lands are the agencies that manage them such as the Bureau of Land Management (BLM), Energy Information Agency (EIA), US Geological Survey (USGS), Office of Natural Resource Revenue (ONRR) and the Department of Interior (DOI).

Where possible we have used the volumes of fossil fuels on federal lands as they are presented in our sources. Where no volume was available, we had to estimate volumes. Onshore and offshore crude oil and natural gas under lease do not have volume estimates available. Data from the Office of Natural Resource Revenue (ONRR) on fiscal years 2014 lease volume revenue and acreage were used, alongside other fossil fuel resource data, to estimate volumes of crude oil and natural gas under lease. Oil shale available under Bureau of Land Management research, development and demonstration (RD&D) leases and its oil shale and tar sands programmatic environmental impact statement and record of decision (OSTS PEIS and ROD) do not have associated volume estimates. Volume estimates were constructed for:

- Onshore Crude Oil Under Lease
- Offshore Crude Oil Under Lease
- Onshore Natural Gas Under Lease
- Offshore Natural Gas Under Lease
- Coal Under Lease
- Oil Shale Available for Lease Under PEIS and ROD
- Oil Shale Available Under RD&D Leases
- Total In Place Federal Oil Shale Resources
- Tar Sands: In Place Federally Owned Resources
- Tar Sands: Lease Available Special Tar Sands Areas
- Unleased Federal Crude Oil
- Unleased Federal Natural Gas
- Unleased Federal Coal

- Unleased Federal Oil Shale
- Unleased Federal Tar Sands
- Non-federal fossil fuels

Onshore Crude Oil Under Lease

The 2008 EPCA inventory estimates the amount of crude oil and natural gas. We used 2014 data to estimate what portion is under active lease. To calculate onshore crude oil under lease, we use the following equation:

$$OCO_{UL} = [ONG_{AUL} \times (FLA_{TRO} \div TA_{AFL})] + OCO_{PR}$$

Where:

OCO_{UL} = Onshore Crude Oil Under Lease, in MMBls

ONG_{AUL} = Fiscal Year 2014 Oil & Natural Gas Nonproducing Acres Under Active Lease

FLA_{TRO}

= Federal lease Available Technically Recoverable Onshore Oil

TA_{AFL} = Total Acres Available for Lease from Figure ES3 of EPCA Phase 3 Inventory 2008

OCO_{PR} = Onshore Crude Oil, Proved, from EPCA Phase 3 Inventory 2008

Offshore Crude Oil Under Lease

To calculate offshore crude oil under lease, we use the following equation:

$$OFCO_{UL} = [OFA_{UAL} \times (OFCO_{LGM} \div OFCO_{LGMA})] + OFCO_{PR}$$

Where:

$OFCO_{UL}$ = Offshore Crude Oil Under Lease, in MMBbls

OFA_{UAL} = 2015 Offshore Nonproducing Acres Under Active Lease

$OFCO_{LGM}$ = Offshore Crude Oil Leased in Gulf of Mexico Nonproducing Volume

$OFCO_{LGMA}$ = Offshore Crude Oil Nonproducing Acres Leased in Gulf of Mexico

$OFCO_{PR}$ = Offshore Crude Oil, Proved, from EPCA Phase 3 Inventory 2008

Onshore Natural Gas Under Lease

To calculate onshore natural gas under lease, we use the following equation:

$$ONG_{UL} = [ONG_{AUL} \times (FLA_{TRNG} \div TA_{AFL})] + ONG_{PR}$$

Where:

ONG_{UL} = Onshore Natural Gas Under Lease, in Tcfg

ONG_{AUL} = Fiscal Year 2014 Oil and Natural Gas Nonproducing Acres Under Lease

FLA_{TRNG} = Federal Lease Available Technically Recoverable Onshore Natural Gas

TA_{AFL} = Total Acres Available for Lease from Figure ES3 of Phase 3 Inventory 2008

ONG_{PR} = Onshore Natural Gas, Proved, from EPCA Phase 3 Inventory 2008

Offshore Natural Gas Under Lease

To calculate offshore natural gas under lease, we use the following equation:

$$OFNG_{UL} = [OFA_{UAL} \times (OFNG_{LGM} \div OFNG_{NP})] + OFNG_{PR}$$

Where:

$OFNG_{UL}$ = Offshore Natural Gas Under Lease, in Tcfg

OFA_{UAL} = Offshore Nonproducing Acres Under Active Lease

$OFNG_{LGM}$ = Offshore Natural Gas Leased in Gulf Of Mexico Nonproducing Volume

$OFNG_{NP}$ = Offshore Natural Gas Nonproducing Acres Leased in Gulf of Mexico

$OFNG_{PR}$ = Offshore Natural Gas, Proved, from EPCA Phase 3 Inventory

Coal Under Lease

Since nominal amounts of coal under lease were not available, we had to estimate them based on data from GAO, BLM, and the percentage of leased and unmined coal reserves remaining in the Powder River Basin. To calculate coal under lease, we used the following equation:

$$C_L = \sum RLC [(LFC_{A,1990-2012} \div LFC_{T,1990-2012}) \times LFC_{A,2013}] \times RFC_R$$

Where:

C_L = Coal Under Lease, in MST

$\sum RLC$ = Sum of Remaining Leased Coal for each of the following States (AL, CO, KY, MT, NM, ND, OK, UT, WY, Eastern States)

$LFC_{A,1990-2012}$ = Leased Federal Coal in Acres (for each state) for the period 1990 – 2012, from Table 1 in GAO 2013

$LFC_{T,1990-2012}$ = Leased Federal Coal in Tons (for each state) for the period 1990 – 2012, from Table 1 in GAO 2013

$LFC_{A,2013}$ = Total Leased Federal Coal Acres in Effect (for each state) in 2013 from BLM 2014

RFC_R = Percentage of leased and unmined coal reserves remaining in Powder River Basin (40.4%) from Wright 2015

Oil Shale Available for Lease Under PEIS and ROD

To calculate the volume of oil shale available for lease under both the PEIS and ROD, we separately estimate the available resource in Utah, Colorado and Wyoming, and sum these estimates.

To estimate the available resource for lease in UT, we use the following equation:

$$OSR_{UT} = AAROD_{UT} \times AR_{UT}$$

Where:

OSR_{UT} = Oil Shale Resource for lease in Utah, in MMBbls
 $AAROD_{UT}$ = Available Area in Utah According to Record of Decision
 AR_{UT} = Average Resource in Utah's Uintah Basin, in bbl/acre

To estimate the available resource for lease in CO, we use the following equation:

$$OSR_{CO} = AAROD_{CO} \times AR_{CO}$$

Where:

OSR_{CO} = Oil Shale Resource in Colorado, in MMBbls
 $AAROD_{CO}$ = Available Area in Colorado According to Record of Decision
 AR_{CO} = Average Resource in Colorado's Piceance Basin, in bbl/acre

To estimate the available resource for lease in WY, we use the following equation:

$$OSR_{WY} = AAROD_{WY} \times AR_{WY}$$

Where:

OSR_{WY} = Oil Shale Resource in Wyoming, in MMBbls
 $AAROD_{WY}$ = Available Area in Wyoming According to Record of Decision
 AR_{WY} = Average Resource in Wyoming's Green River and Washakie Basins, comprised of the average of 6 members, in bbl/acre

Oil Shale Available Under RD&D Leases

To calculate the volume of oil shale available under RD&D leases, we summed up the estimated volumes for the 9 leases detailed in the *Assessment of Plans and Progress on US Bureau of Land Management Oil Shale RD&D Leases in the United States*.¹⁴

Since volume estimates for the American Shale Oil LLC and AuraSource leases are not available in the document, we estimate them using the following equations:

$$OSR_{ASO} = AAL_{ASO} \times AR_{CO}$$

Where:

OSR_{ASO} = Oil Shale Resource in the American Shale Oil, LLC Lease, in MMBbls
 AAL_{ASO}
= Area Available For Lease (including preference right area) for the American Shale Oil, LLC lease
 AR_{CO} = Average Resource in Colorado's Piceance Basin, in bbl/acre

$$OSR_{AS} = AAL_{AS} \times AR_{UT}$$

Where:

OSR_{AS} = Oil Shale Resource in the AuraSource Lease, in MMBbls
 AAL_{AS} = Area Available For Lease (including preference right area) for the AuraSource lease
 AR_{UT} = Average Resource in Utah's Uintah Basin, in bbl/acre

Total In Place and Geologically Prospective Federal Oil Shale Resources

To calculate the total in place federal oil shale resources, we summed the federal resource available in the Piceance Basin with a yield of over 25 GPT (gallon per ton) in USGS 2010, the federal resource available in the Green River and Washakie Basins of over 15 GPT in USGS 2011, and separately estimated the federal resource available in the Uintah basin.

To estimate the federal resource in the Uintah basin, we use the following equation

$$FOSR_{UB} = AAROD_{UT} \times AR_{UT}$$

Where:

$FOSR_{UB}$ = Federal Oil Shale Resource in the Uintah Basin, in MMBbls

$AAROD_{UT}$ = Available Area in Utah According to Record of Decision

AR_{UT} = Average Resource in Uintah Basin, in bbl/acre

Tar Sands: In Place Federally Owned Resources

To calculate the volume of in place federally owned tar sands resources, we use the following equation:

$$TS_{FOR} = \sum SRfp$$

Where:

TS_{FOR} = In Place Federally Owned Tar Sands Resources, in MMBbl

$\sum SRfp$ = the sum of the federally owned percentages of tar sands resource for each state

As mentioned above, we sum the federally owned percentages of tar sands resources as listed in *Natural Bitumen Resources of the United States*.¹⁵ Where no federal ownership percentage is given in the document, we cite research by Keiter et al. 2012 for the percentage of Utah tar sands that are federal and Gorte et al. 2011 for all other states.

Tar Sands: Lease Available STSAs

To calculate the volume for Lease Available STSAs, we multiply the area available for each STSA by the resource for that area. STSA areas are taken from as presented in the 2013 ROD.¹⁶

The available resource for each area is taken from *Unconventional Energy Resources: 2013 Review*.¹⁷ This review unfortunately does not provide estimates for Raven Ridge

or San Rafael STSAs; for those, we used a low per-acre estimate (from the P.R. Spring STSA) of 25,900 barrels per acre. We then sum all of these volumes.

Unleased Federal Crude Oil

To calculate unleased federal offshore crude oil, we use the following equation:

$$OFCO_{ULL} = OFCO_{TR}$$

Where:

$OFCO_{ULL}$ = Unleased Federal Offshore Crude Oil

$OFCO_{TR}$ = Technically Recoverable Federal Offshore Crude Oil

To calculate unleased federal onshore crude oil, we use the following equation:

$$OCO_{ULL} = OCO_{TR}$$

Where:

OCO_{ULL} = Unleased Federal Onshore Crude Oil

OCO_{TR} = Technically Recoverable Federal Onshore Crude Oil

Unleased Federal Natural Gas

To calculate unleased federal offshore natural gas, we use the following equation:

$$OFNG_{ULL} = OFNG_{TR}$$

Where:

$OFNG_{ULL}$ = Unleased Federal Offshore Natural Gas

$OFNG_{TR}$ = Technically Recoverable Federal Offshore Natural Gas

To calculate unleased federal onshore natural gas, we use the following equation:

$$ONG_{ULL} = ONG_{TR}$$

Where:

ONG_{ULL} = Unleased Federal Onshore Natural Gas

ONG_{TR} = Technically Recoverable Federal Onshore Natural Gas

Unleased Federal Coal

To calculate unleased federal coal, we use the following equation:

$$FC_{ULL} = FC_{RR} - \left\{ \left(\frac{FC_{TIR}}{BLM_{AUM}} \right) \times CLA_{2013} \right\}$$

Where:

FC_{ULL} = Unleased Federal Coal

FC_{RR} = Federal Recoverable Coal Reserves from NMA 2012

FC_{TIR} = Total Federal In Place Coal Resource from USDA, USDOE, USDOl 2007

BLM_{AUM} = Acres Under BLM Management from BLM 2014

CLA_{2013} = 2013 Leased Coal Acres from BLM 2014

Unleased Federal Oil Shale

To calculate unleased federal oil shale, we subtract Federal Oil Shale Available under RD&D Leases from DOE/BLM 2013 from Total In Place Geologically Prospective Federal Oil Shale Resources as described earlier.

Unleased Federal Tar Sands

To calculate unleased federal tar sands, we assume the total in place federal tar sands resources are unleased.

Non-federal Fossil Fuels

Non-federal fossil fuels volumes are calculated for each fossil fuel category by subtracting federal fossil fuel volumes from total technically recoverable oil resources, total technically recoverable natural gas resources, and total us recoverable coal reserves in the U.S. as provided by EIA 2012a. There are no non-federal tar sands and oil shale resources studied in this study.

For each oil, natural gas and coal resource:

$$NFFF = TTR - FFF$$

Where:

$NFFF$ = Non-federal Fossil Fuel

TTR = Total Technically Recoverable Resource

FFF = Federal Fossil Fuel

A2. Fossil Fuel to Primary Energy Conversions

We converted volumes of fossil fuels into primary energy as this allowed us to make necessary adjustments and apply resource specific life-cycle GHG emissions factors, as those are presented in units of energy. For example, the life-cycle GHG emissions factors are typically on a product-delivered basis (kWh of electricity, MJ of thermal energy), so the fossil fuel reserves must be adjusted because only a portion of the fossil fuel becomes a final product delivered.

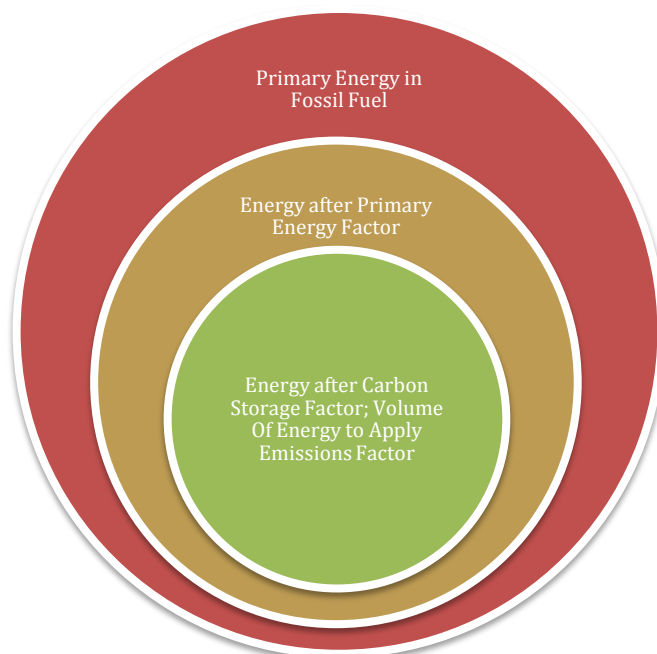


Figure A17. Determining quantities of energy to multiply by emissions factor

We used the following assumptions to convert fossil fuel amounts to primary energy:

Table A10. Energy content of fossil fuels

Fossil Fuel	Energy Content	Source
Crude Oil	5,746 MJ / barrel (LHV)	ORNL 2011
Natural Gas	983 btu / ft3 (LHV)	ORNL 2011
Coal	20.61 btu / ton (HHV)	ORNL 2011
Oil Shale	5,746 MJ / barrel (LHV)	ORNL 2011
Tar Sands	5,746 MJ / barrel (LHV)	ORNL 2011

Proportions of Resource Used as Input for End-use Products

The proportions of resource used as input for end-use products were needed in order to appropriately divide the initial fossil fuel amounts. The proportions make it possible to apply end-use product specific life-cycle emissions factors, which account for the full

life-cycle GHG emissions associated with each end-use product. These proportions do not take into account the energy required to process the fossil fuel resource and move it downstream. They only describe a percentage of the fossil fuel resource that will ultimately be used in end-use products and sectors.

Crude Oil

Proportions of Crude Oil used for various end-use products were derived from the EIA.¹⁸ To calculate proportions each of the top seven petroleum products consumed in 2013 was divided by the total annual consumption of petroleum products. These top seven products are:

- Finished Motor Gasoline
- Distillate Fuel Oil
- Kerosene
- Liquefied Petroleum Gases (LPG)
- Petroleum Coke
- Still Gas
- Residual Fuel Oil

Dividing the consumption of each end product by the total annual consumption of petroleum products enabled us to reconstruct the demand for petroleum products, and thus the hypothetical product output of a crude oil refinery.

For this method, we used the following equation:

$$CO_{EUPP} = AC_{EUP} \div AC_{APP}$$

Where:

CO_{EUPP} = Crude Oil End Use Product Proportion

AC_{EUP} = Annual Consumption of End Use Product

AC_{APP} = Annual Consumption of All Petroleum Products

Natural Gas

Proportions of Natural Gas used for each end-use sector were derived from the EIA's *Natural Gas Consumption by Sector in the Reference case, 1990-2040: History: U.S. Energy Information Administration, Monthly Energy Review*.¹⁹ For each end-use sector, the sector specific annual natural gas consumption was divided by the total annual natural gas consumption. These end-use sectors are:

- Residential
- Commercial
- Industrial
- Electric Power
- Transportation

For this method we used the following equation:

$$NG_{EUSP} = AC_{EUS} \div AC_{ANG}$$

Where:

NG_{EUSP} = Natural Gas End Use Sector Proportion

AC_{EUS} = Annual Consumption by End Use Sector

AC_{ANG} = Annual Consumption of All Natural Gas

Coal

Proportions of Coal used for each end-use sector were derived from the EIA's *Quarterly Coal Report – April – June 2014: Table 32 - U.S. Coal Consumption by End-Use Sector, 2008 – 2014*.²⁰ For each end-use sector, the sector specific annual coal consumption was divided by the total annual coal consumption. These end-use sectors are:

- Electric Power
- Coke
- Other Industrial Use

For this method, we use the following equation:

$$C_{EUSP} = AC_{EUS} \div AC_{AC}$$

Where:

C_{EUSP} = Coal End Use Sector Proportion

AC_{EUS} = Annual Consumption by End Use Sector

AC_{AC} = Annual Consumption of All Coal

Oil Shale

For oil shale we assume the same end-use products will be refined from a barrel of crude oil derived from oil shale. We apply the same end-use product proportions as calculated for Crude Oil.

Tar Sands

For tar sands we assume the same end-use products will be refined from a barrel of crude oil derived from tar sands as has been assumed in other research.²¹ We apply the same end-use product proportions as calculated for Crude Oil.

Primary Energy Factors

Making energy products requires energy. To account for the energy in the reserve required to make the final end products, we determined a ratio of primary energy to the end use, resulting in a Primary Energy Factor. The Primary Energy Factor represents the relationship between the amount of energy required to make the end product and the amount of end product. In the case of coal-based electricity, it is the amount of energy needed to make 1 kWh of coal fired electricity, which will always be >1 kWh. For this study only about 30% of the total coal resource becomes electricity delivered from coal-fired generation; it requires about 3.3 kWh of coal resource to make and deliver 1 kWh of coal electricity. Our methodology assumes the energy required to process the fossil fuel resource into the end product is internal, meaning it comes from the resource. This means that some portion of the fossil fuel resource is consumed making the fossil fuel product. The primary energy factor helps understand the total amount of fossil fuel products and has no impact on the life-cycle GHG emissions, which are accounted for in the emissions factors.

For many end products, primary energy factors are available, as “source energy factors” from the National Renewable Energy Laboratory’s *Fuels and Energy Precombustion LCI Data Module*.²² We used these source energy factors, which represent the energy required to extract, process, and deliver fuel, as Primary Energy Factors. We used NREL’s ‘source energy factors’ for all end products except:

- Natural Gas Use in the Electric Power Sector
- Coal Use in the Electric Power Sector
- Coal Use in manufacturing Metallurgical Coke
- Coal Use in Other Industrial Use
- End Products Derived from Oil Shale and Tar Sands

Natural Gas Use in the Electric Power Sector

To calculate the Primary Energy Factor for Natural Gas Use in the Electric Power Sector, we converted the volume (ft³) of Natural Gas delivered in 2013 to customers in the Electric Power Sector from EIA’s *February 2015 Monthly Energy Review*²³ into kWh, took the 2013 net electrical generation from Natural Gas (kWh) by Electric Power Sector customers in EIA’s *February 2015 Monthly Energy Review*,²⁴ and the source energy factor for Natural Gas from Deru and Torcellini 2007.

To calculate the Primary Energy Factor for Natural Gas Use in the Electric Power Sector, we used the following equation:

$$PEFNG_{EPS} = NGD_{EPS} \div NEGNG_{EPS}$$

Where:

$PEFNG_{EPS}$ = Primary Energy Factor for Natural Gas Use in the Electric Power Sector

NGD_{EPS} = Natural Gas Delivered to Electric Power Sector Customers in 2013

$NEGNG_{EPS}$ = Net Electrical Generation from Natural Gas by Electric Power

For other Natural Gas end-use sectors, we assume all heat not converted to electricity is useful. For the Electric Power Sector, however, we assume all heat is lost.

Coal Use in the Electric Power Sector

For Coal Use in the Electric Power Sector, we converted the quantity of coal consumed by the Electric Power Sector in *Quarterly Coal Report – April – June 2014: Table 32 - U.S. Coal Consumption by End-Use Sector, 2008 – 2014*²⁵ into kWh, we took the 2013 net electrical generation from Coal (kWh) by Electric Power Sector customers in EIA's *February 2015 Monthly Energy Review* (2015b), and the source energy factor for Coal.²⁶

To calculate the Primary Energy for Coal Use in the Electric Power Sector, we used the following equation:

$$PEFC_{EPS} = CD_{EPS} \div NEGC_{EPS}$$

Where:

$PEFC_{EPS}$ = Primary Energy Factor for Coal Use in the Electric Power Sector

CD_{EPS} = Coal Delivered to Electric Power Sector Customers in 2013

$NEGC_{EPS}$ = Net Electrical Generation from Coal by Electric Power Customers in 2013

For Coal Use in the manufacture of Metallurgical Coke, we used values in World Coal Association 2015. For Coal Use in Other Industrial Use, we use the same Primary Energy Factor as that calculated for Coal Use in the Electric Power sector.

End Products Derived From Oil Shale and Tar Sands

The primary energy resource available for end products derived from oil shale and tar sands needs to be adjusted for the increased energy required to extract and process both the oil shale and tar sands. We assume the additional energy required for these processes comes from the primary energy resource itself, otherwise referred to as 'internal' energy. Since the primary energy factors used²⁷ are aggregates of several components (exploration, extraction, processing, and refining into end products), and do not list the primary energy factors for each of these components, we had to disaggregate the factors and backwards calculate the primary energy factor of just the refining component. To do this we use the following equation for each end product derived from crude oil:

$$PEFCO_{REP} = (PEFCO_{EP}) - \left(\frac{1}{EROI_{CO}}\right)$$

Where:

$PEFCO_{REP}$

= Primary Energy Factor of Refining the End Product From Crude Oil, exclusive of energy required for exploration, extraction, and processing

$PEFCO_{EP}$ = Primary Energy Factor of End Product, inclusive of all processes

$EROI_{CO}$ = Energy Return On Investment from Crude Oil

For End Products Derived from Oil Shale, we adjust the Primary Energy Factors of refining components of end products derived from Crude Oil by the following adjustment mechanism:

$$PEFOS_{EP} = PEFCO_{REP} + \left(\frac{1}{EROI_{OS}} \right)$$

Where:

$PEFOS_{EP}$ = Primary Energy Factor of Oil Shale Derived End Product

$PEFCO_{REP}$ = Primary Energy Factor of Refining Component of End Product

$EROI_{OS}$ = Energy Return ON Investment from Oil Shale, from Brand 2009

For End Products Derived from Tar Sands, we adjust the Primary Energy Factors of refining components of end products derived from Crude Oil by the following adjustment mechanism:

$$PEFTS_{EP} = PEFCO_{REP} + \left(\frac{1}{EROI_{TS}} \right)$$

Where:

$PEFOS_{EP}$ = Primary Energy Factor of Oil Shale Derived End Product

$PEFCO_{REP}$ = Primary Energy Factor of Refining Component of End Product

$EROI_{OS}$ = Energy Return ON Investment from Oil Shale²⁸

Emissions Factors

The approach used in this study was to use emissions factors that represent the functional units for which we had data on fossil fuels amounts. For example, if the functional unit of the emissions factor was a kWh worth of electricity, we estimated the total amount of resource that can be converted into this functional unit. Where the emissions factor is provided on an energy unit basis that is not equivalent to that of the fossil fuel resource, we make the appropriate conversion.

All life-cycle emissions factors used in this study, and nearly all in the literature, are on an end-use product basis (i.e., kWh of electricity, MJ of final fuel combusted, km-travelled, etc.). To account for the energy in the feedstock required to make the end-use products, we determined a ratio of primary energy to the end-use product, as described 40

earlier in this Appendix. This represents the relationship between the amount of energy required to make the final product.

We were able to find resource-specific life-cycle emissions factors for all fossil fuel categories. These life-cycle emissions factors account for the greenhouse gas emissions associated with all life-cycle stages associated with the production of an end product derived from a fossil fuel feedstock.

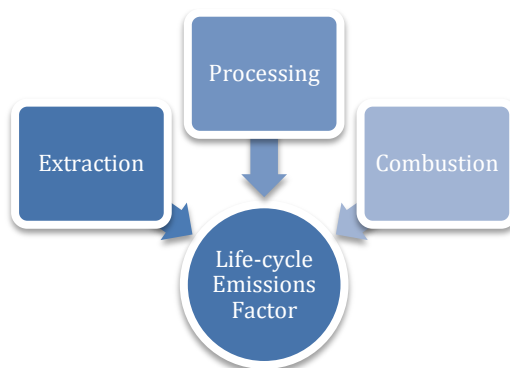


Figure A18. Example life-cycle stages accounted for in a life-cycle emissions factor

For each emissions factor we evaluated low, median and high emission factor scenarios. The base case in this study is the low emissions factor scenario, which is the most conservative estimate of the GHG emissions from developing fossil fuels. This was done to account for a static emissions factor; we optimistically assume that GHG emissions per unit energy improve over time compared to *ex post* emissions factors in the literature as more efficient energy and public policy and best practices limit fugitive emissions.

Where possible we used harmonized life-cycle emissions factors found in the literature. Harmonization is a meta-analytical process used to develop robust, analytically consistent and current comparisons of estimates of life-cycle GHG emissions factors, which have been scientifically studied and published in academic, peer-reviewed literature.

For some end-use products, however, specific emissions factors were not available in the literature. We make adjustments to the emissions factors for the following:

- Natural Gas extracted from non-conventional, shale based natural gas resource
- All end products (except Gasoline) derived from Oil Shale
- LPG, Petroleum Coke, Still Gas, and Residual Fuel Oil derived from Tar Sands
- Natural Gas Used in the Transportation Sector

Natural Gas Extracted From Non-Conventional, Shale-based Natural Gas Resource

To account for the difference in emissions resulting from conventional natural gas extraction and non-conventional natural gas extraction, we apply shale-gas specific emissions-factors to a percentage of the total Natural Gas fossil fuel volume. We assume this to be 27% and take this figure from EIA's *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States* (2013). We use shale-gas specific emissions factors from Burnham et al. 2012 and Heath et al. 2014.

All End Products (Except Gasoline) Derived From Oil Shale

Specific emissions factors for finished motor gasoline derived from oil shale was available in the literature. Emissions factors for the remainder of the end products, however, were not.

To account for the difference in emissions between conventional crude oil extraction and processing and the extraction and processing of Oil Shale into an equivalent barrel of standard crude oil, we adjust the end product specific emissions factors using the following equation:

$$OSE_{AF} = (FMG_{OS} - FMG_{CO}) \div FMG_{CO}$$

Where:

OSE_{AF} = Oil Shale Emissions Adjustment Factor

FMG_{OS} = Finished Motor Gasoline from Oil Shale Emissions Factor from Brandt 2009

FMG_{CO} = Finished Motor Gasoline from Crude Oil Emissions Factor from Burnham, et al. 2012

We then multiply each crude oil end product specific emissions factor by $(1 + OSE_{AF})$ to appropriately increase the emissions factor due to the increased emissions resulting from Oil Shale extraction and processing. The emissions factor from Brandt 2009 used above is an Oil Shale specific emissions factor.

LPG, Petroleum Coke, Still Gas and Residual Fuel Oil Derived From Tar Sands

Specific emissions factors for finished motor gasoline, distillate fuel oil and kerosene were available in the literature. However, specific emissions factors for other end-use products were not. To account for the difference in emissions between conventional crude oil extraction and processing and the extraction and processing of Tar Sands into an equivalent barrel of standard crude oil, we adjust the end product specific emissions factors using the following equation:

TSE_{AF} = the average of:

$$(FMG_{TS} - FMG_{CO}) \div FMG_{CO};$$

$$(DFO_{TS} - DFO_{CO}) \div DFO_{CO};$$

and

$$(K_{TS} - K_{CO}) \div K_{CO}$$

Where:

TSE_{AF} = Tar Sands Emissions Adjustment Factor

FMG_{TS} = Finished Motor Gasoline from Tar Sands Emissions Factor²⁹

FMG_{CO} = Finished Motor Gasoline from Crude Oil Emissions Factor³⁰

DFO_{TS} = Distillate Fuel Oil from Tar Sands Emissions Factor³¹

DFO_{CO} = Distillate Fuel Oil from Crude Oil Emissions Factor³²

K_{TS} = Kerosene from Tar Sands Emissions Factor³³

K_{CO} = Kerosene from Crude Oil Emissions Factor³⁴

We then multiply the LPG, Petroleum Coke, Still Gas and Residual Fuel Oil from Crude Oil emissions factors by $(1 + TSE_{AF})$.

Natural Gas Used in the Transportation Sector

In order to more accurately estimate the emissions from natural gas use in the transportation sector, we use EIA data³⁵ to determine what percentage of natural gas is used by light duty compressed natural gas (CNG) vehicles, and what percentage is used by medium and heavy duty CNG vehicles. We then apply these proportions to the transportation portion of natural gas primary energy volumes.

To calculate GHG emissions, we use life-cycle emissions factors for CNG transportation.³⁶ Since the emissions factors from Burnham et al. are measured in km-travelled, we need the fuel economy to determine the distance each mode of transport can travel based upon a unit of gas. We use EPA data to estimate the fuel economy of light duty vehicles.³⁷ For the fuel economy of medium and heavy duty vehicles, we cite research from NREL.³⁸ Once energy available is expressed in the functional units of the life-cycle emissions factors, we can estimate potential GHGs.

Research Limitations

There are several limitations to this model. The major limitation is the unavailability of some kinds of data that would allow for a better approximation of global warming potential from developing fossil fuels. For example, tar sands reserves are not well characterized as amounts are reported in “acres” and estimates must be made by applying a “barrel per acre” estimate instead of absolute amounts, which would be easier to compare with other reserves. In addition, existing fossil fuel amounts under lease were mostly unavailable. There is also no specific data for all of the crude oil end products. Literature on life-cycle emissions factors for oil shale and tar sands not as extensive as for other resources and come with higher ranges of uncertainty. There is also no federal ownership of figures for Tar Sands in Alabama, Texas, California, Kentucky, New Mexico, Wyoming and Oklahoma. Finally, emissions factors used in this study were static over time and based on *ex post* (actual) data. Our GHG emissions

model assumes that the combustion efficiency or GHG intensity across the fleet of U.S. fossil fuel-fired power plants remains static over time.

Appendix II: Data Sources

Table A11. Fossil fuel amounts and sources

Fossil Fuel Type	Quantity	Source(s) Used
Crude Oil		
Offshore		
Federal Technically Recoverable	89,930 MMBbls	BOEM 2014
Federal Proved (2013)	5,137 MMBbls	EIA 2015a
FY 2014 Crude Oil Volume Revenues Reported	396.36 MMBbls	ONRR 2014
February 2015 Producing Leases – Acreage	4,980,054 acres	BOEM 2015
Acreage Under Active Lease	32,184,001 acres	BOEM 2015
Leased in Gulf of Mexico (non-producing/not subject to exploration & development plans)	17,900 MMBbls	DOI 2012
Non-producing Acreage Leased in Gulf of Mexico	23,849,584 acres	BOEM 2015
All Non-producing Acreage Leased	27,203,947 acres	DOI 2012
Onshore		
Federal Technically Recoverable	30,503 MMBbls	EPCA Phase 3 Inventory 2008
Federal Lease Available Technically Recoverable*	18,989 MMBbls	EPCA Phase 3 Inventory 2008
Federal Proved	5,344 MMBbls	EPCA Phase 3 Inventory 2008
FY 2014 Crude Oil Volume Revenues Reported	146.23 MMBbls	ONRR 2014
FY 2014 O&NG Producing Leases – Acreage	12,690,806 acres	BLM 2014a
FY 2014 O&NG Acres Under Lease	34,592,450 acres	BLM 2014a
Total Technically Recoverable Resource	220,200 MMBbls	EIA 2012a
Natural Gas		
Offshore		
Technically Recoverable	404.52 Tcfg	BOEM 2014
Federal Proved Gas	25.33 Tcfg	EIA 2014c
FY 2014 Natural Gas Volume Revenues Reported	0.85 Tcfg	ONRR 2014
February 2015 Producing Leases – Acreage	4,980,054 acres	BOEM 2015
Acreage Under Active Lease	32,184,001 acres	BOEM 2015
Leased in Gulf of Mexico (non-producing/not subject to exploration & development plans)	49.70 Tcfg	DOI 2012
Non-producing Acreage Leased in Gulf of Mexico	23,849,584 acres	BOEM 2015
All Non-producing Acreage Leased	27,203,947 acres	BOEM 2015
Onshore		
Technically Recoverable	230.98 Tcfg	EPCA Phase 3 Inventory 2008
Lease Available Technically Recoverable*	194.907 Tcfg	EPCA Phase 3 Inventory 2008
Proved Gas	68.76 Tcfg	EPCA Phase 3 Inventory 2008

Total Technically Recoverable Resource	2,203.30 Tcfg	EIA 2012a
Coal		
In Place Federal Coal Resources	957,000 MST	USDA, DOE, DOI 2007
Federal Recoverable Coal Reserves	87,000 MST	National Mining Association 2012
Total U.S. Recoverable Reserves	256,000 MST	EIA 2012b
2013 Leased Coal Acres	474,025 acres	BLM 2014b
2013 Coal Production	422.25 MST	ONRR 2013
Oil Shale		
Available Area According to ROD – UT*	360,400 acres	BLM ROD 2013
Available Area According to ROD – CO*	26,300 acres	BLM ROD 2013
Available Area According to ROD – WY*	292,000 acres	BLM ROD 2013
Average Resource – UT	74,093 bbl/acre	BLM OSTS 2012
Average Resource – WY	120,117 bbl/acre	BLM OSTS 2012
Average Resource – CO	300,000 bbl/acre	Mercier, et al. 2010
Resource Available in Piceance Basin	284,800 MMBbls	USGS 2010
Resource Available in Green River and Washakie Basins	72,179 MMBbls	USGS 2011
Resource Available in Uinta Basin	26,699 MMBbls	BLM OSTS 2012; BLM ROD 2013
Available Under RD&D Leases	5,938 MMBbls	DOE/BLM 2013
Tar Sands		
In Place Tar Sands Resources	54,095 MMBbls	USGS 2006
Federal Ownership of Utah Tar Sands	58%	Keiter et al. 2011
Federal Ownership of Other Tar Sands	28%	Gorte et al. 2012
Lease Available STSAs*	4,125 MMBbls	BLM OSTS 2012

* “Lease-available” federal fossil fuels are unleased federal fossil fuels that are available for leasing under current federal policies and plans.

Table A12. End-use products/sectors and life-cycle emissions factor sources

End-use Product / Sector	Key Parameter(s) for Influencing Low, Median, High Emissions Scenarios	Life-Cycle Emission Factor Source(s) Used
<u>Crude Oil</u>		
Gasoline	Associated gas venting and flaring; vehicle end-use efficiency	Burnham et al. 2012
Distillate Fuel Oil	Extraction and transport	NETL 2008, 2009 as cited in US DOS 2014
Kerosene	Extraction and transport	NETL 2008, 2009 as cited in US DOS 2014
Liquefied Petroleum Gases (LPG)	Extraction and transport	Venkatesh et al. 2010
Petroleum Coke	Extraction and transport	Venkatesh et al. 2010
Still Gas	Extraction and transport	Venkatesh et al. 2010
Residual Fuel Oil	Extraction and transport	Venkatesh et al. 2010
<u>Natural Gas</u>		
Residential	Liquid unloadings (venting); well equipment (leakage and venting); transmission and distribution (leakage and venting)	Burnham et al. 2012
Commercial	Liquid unloadings (venting); well equipment (leakage and venting); transmission and distribution (leakage and venting)	Burnham et al. 2012
Industrial	Liquid unloadings (venting); well equipment (leakage and venting); transmission and distribution (leakage and venting)	Burnham et al. 2012
Electric Power	Power conversion efficiency	Heath et al. 2014
Transportation	Liquid unloadings (venting); well equipment (leakage and venting); transmission and distribution (leakage and venting)	Burnham et al. 2012
<u>Coal</u>		
Electric Power	Transmission and distribution losses; power conversion efficiency; coal mine methane	Whitaker et al. 2012
Coke		EPA 2004
Other Industrial Use	Transmission and distribution losses; power conversion efficiency; coal mine methane	Whitaker et al. 2012
<u>Oil Shale</u>		
Gasoline	Retorting; upgrading; refining	Brandt 2009
Distillate Fuel Oil	Retorting; upgrading; refining; extraction	Brandt 2009; Burnham et al. 2012; NETL 2008, 2009 as cited in US DOS 2014
Liquefied Petroleum Gases (LPG)	Retorting; upgrading; refining; extraction; transport	Brandt 2009; Burnham et al. 2012; Venkatesh et al. 2010
Kerosene	Retorting; upgrading; refining; extraction; transport	Brandt 2009; Burnham et al. 2012; NETL 2008, 2009 as cited in US DOS 2014
Petroleum Coke	Retorting; upgrading; refining;	Brandt 2009; Burnham et al. 2012;

	extraction; transport	Venkatesh et al. 2010
Still Gas	Retorting; upgrading; refining; extraction; transport	Brandt 2009; Burnham, et al. 2012; Venkatesh et al. 2010
Residual Fuel Oil	Retorting; upgrading; refining; extraction; transport	Brandt 2009; Burnham et al. 2012; Venkatesh et al. 2010
<u>Tar Sands</u>		
Gasoline	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	Jacobs 2009, NETL 2008, 2009, and TIAX 2009 as cited in DOS 2014
Distillate Fuel Oil	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	Jacobs 2009, and NETL 2008, 2009 as cited in DOS 2014
Liquefied Petroleum Gases (LPG)	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	Jacobs 2009, NETL 2008, 2009, and TIAX 2009 as cited in US DOS 2014; Venkatesh et al. 2010
Kerosene	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	NETL 2008, 2009 as cited in DOS 2014
Petroleum Coke	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	Jacobs 2009, NETL 2008, 2009, and TIAX 2009 as cited in DOS 2014; Venkatesh et al. 2010
Still Gas	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	Jacobs 2009, NETL 2008, 2009, and TIAX 2009 as cited in DOS 2014; Venkatesh et al. 2010
Residual Fuel Oil	Feedstock mixture (consisting of dilbit, synthetic crude oil, bitumen)	Jacobs 2009, NETL 2008, 2009, and TIAX 2009 as cited in DOS 2014; Venkatesh et al. 2010

Table A13. Crude oil end products and emissions factors

Crude Oil End-use Product	Proportion of Resource Used as Input for End-use Product	Carbon Storage Factor	Low Emissions Factor	Median Emissions Factor	High Emissions Factor	Primary Energy Factor
Finished Motor Gasoline	46.46%	0.00	86 tons CO ₂ e / TJ Fuel Combusted	92 tons CO ₂ e / TJ Fuel Combusted	98 tons CO ₂ e / TJ Fuel Combusted	1.19
Distillate Fuel Oil	17.92%	0.50	89 tons CO ₂ e / TJ Fuel Combusted	90 tons CO ₂ e / TJ Fuel Combusted	96 tons CO ₂ e / TJ Fuel Combusted	1.16
Kerosene	7.51%	0.00	86 tons CO ₂ e / TJ Fuel Combusted	88 tons CO ₂ e / TJ Fuel Combusted	91 tons CO ₂ e / TJ Fuel Combusted	1.21
Liquefied Petroleum Gases	12.75%	0.59	80 tons CO ₂ e / TJ Fuel Combusted	88 tons CO ₂ e / TJ Fuel Combusted	100 tons CO ₂ e / TJ Fuel Combusted	1.15
Petroleum Coke	1.87%	0.30	130 tons CO ₂ e / TJ Fuel Combusted	144 tons CO ₂ e / TJ Fuel Combusted	160 tons CO ₂ e / TJ Fuel Combusted	1.05
Still Gas	3.72%	0.59	78 tons CO ₂ e / TJ Fuel Combusted	87 tons CO ₂ e / TJ Fuel Combusted	100 tons CO ₂ e / TJ Fuel Combusted	1.09
Residual Fuel Oil	1.70%	0.00	88 tons CO ₂ e / TJ Fuel Combusted	95 tons CO ₂ e / TJ Fuel Combusted	110 tons CO ₂ e / TJ Fuel Combusted	1.19
Asphalt*	1.71%	1.00		--		--
Other Oils*	0.56%	1.00		--		--
Lubricants*	0.64%	1.00		--		--
Other*	5.16%	1.00		--		--

Table A14. Natural gas end-use sectors and factors

Natural Gas End-use Sector (product)	Proportion of Resource Used as Input for End-use Product	Primary Energy Yield Factor	Low Emissions Factor	Median Emissions Factor	High Emissions Factor	Primary Energy Factor
Residential (CHP)	18.76%	100%	72 tons CO ₂ e / MJ of fuel combusted	76 tons CO ₂ e / MJ of fuel combusted	81 tons CO ₂ e / MJ of fuel combusted	1.092
Commercial (CHP)	12.44%	100%	72 tons CO ₂ e / MJ of fuel combusted	76 tons CO ₂ e / MJ of fuel combusted	81 tons CO ₂ e / MJ of fuel combusted	1.092
Industrial (CHP)	34.14%	100%	72 tons CO ₂ e / MJ of fuel combusted	76 tons CO ₂ e / MJ of fuel combusted	81 tons CO ₂ e / MJ of fuel combusted	1.092
Electric Power (kWh)	31.69%	43.39%	117 tons CO ₂ e / MJ of fuel combusted	125 tons CO ₂ e / MJ of fuel combusted	180 tons CO ₂ e / MJ of fuel combusted	1.092
Transportation (km-travelled)	2.98%	100%	210 grams CO ₂ e / km travelled	230 grams CO ₂ e / km travelled	250 grams CO ₂ e / km travelled	1.092

Table A15. Coal end-use sectors and factors

Coal End-use Sector (product)	Proportion of Resource Used as Input for End-use Product	Primary Energy Yield Factor	Low Emissions Factor	Median Emissions Factor	High Emissions Factor	Primary Energy Factor
Electric Power (kWh)	92.78%	31.65%	203 tons CO ₂ e / TJ of fuel combusted	272 tons CO ₂ e / TJ of fuel combusted	381 tons CO ₂ e / TJ of fuel combusted	1.048
Metallurgical Coke (pig iron)	2.32%	n/a		1.35 tons of CO ₂ e / ton of pig iron produced		1.167
Other Industrial Use (kWh)	4.89%	31.65%	203 tons CO ₂ e / TJ of fuel combusted	272 tons of CO ₂ e / TJ of fuel combusted	381 tons CO ₂ e / TJ of fuel combusted	1.048

Table A16. Oil shale end-use products and factors

Oil Shale End-use Product	Proportion of Resource Used as Input for End-use Product	Carbon Storage Factor	Low Emissions Factor	Median Emissions Factor	High Emissions Factor	Primary Energy Factor
Finished Motor Gasoline	46.46%	0.00	130 tons CO ₂ e / TJ Fuel Combusted	141 tons CO ₂ e / TJ Fuel Combusted	150 tons CO ₂ e / TJ Fuel Combusted	1.187
Distillate Fuel Oil	17.92%	0.50	135 tons CO ₂ e / TJ Fuel Combusted	138 tons CO ₂ e / TJ Fuel Combusted	147 tons CO ₂ e / TJ Fuel Combusted	1.158
Kerosene	7.51%	0.00	130 tons CO ₂ e / TJ Fuel Combusted	135 tons CO ₂ e / TJ Fuel Combusted	139 tons CO ₂ e / TJ Fuel Combusted	1.205
Liquefied Petroleum Gases	12.75%	0.59	121 tons CO ₂ e / TJ Fuel Combusted	135 tons CO ₂ e / TJ Fuel Combusted	153 tons CO ₂ e / TJ Fuel Combusted	1.151
Petroleum Coke	1.87%	0.30	197 tons CO ₂ e / TJ Fuel Combusted	221 tons CO ₂ e / TJ Fuel Combusted	245 tons CO ₂ e / TJ Fuel Combusted	1.048
Still Gas	3.72%	0.59	118 tons CO ₂ e / TJ Fuel Combusted	133 tons CO ₂ e / TJ Fuel Combusted	153 tons CO ₂ e / TJ Fuel Combusted	1.092
Residual Fuel Oil	1.70%	0.00	133 tons CO ₂ e / TJ Fuel Combusted	146 tons CO ₂ e / TJ Fuel Combusted	168 tons CO ₂ e / TJ Fuel Combusted	1.191
Asphalt*	1.71%	1.00		--		--
Other Oils*	0.56%	1.00		--		--
Lubricants*	0.64%	1.00		--		--
Other*	5.16%	1.00		--		--

Table A17. Tar sands end-use products and factors

Tar Sands End-use Product	Proportion of Resource Used as Input for End-use Product	Carbon Storage Factor	Low Emissions Factor	Median Emissions Factor	High Emissions Factor	Primary Energy Factor
Finished Motor Gasoline	46.46%	0.00	106 tons CO ₂ e / TJ Fuel Combusted	106 tons CO ₂ e / TJ Fuel Combusted	106 tons CO ₂ e / TJ Fuel Combusted	1.187
Distillate Fuel Oil	17.92%	0.50	105 tons CO ₂ e / TJ Fuel Combusted	105 tons CO ₂ e / TJ Fuel Combusted	105 tons CO ₂ e / TJ Fuel Combusted	1.158
Kerosene	7.51%	0.00	96 tons CO ₂ e / TJ Fuel Combusted	102 tons CO ₂ e / TJ Fuel Combusted	110 tons CO ₂ e / TJ Fuel Combusted	1.205
Liquefied Petroleum Gases	12.75%	0.59	102 tons CO ₂ e / TJ Fuel Combusted	102 tons CO ₂ e / TJ Fuel Combusted	102 tons CO ₂ e / TJ Fuel Combusted	1.151
Petroleum Coke	1.87%	0.30	156 tons CO ₂ e / TJ Fuel Combusted	167 tons CO ₂ e / TJ Fuel Combusted	176 tons CO ₂ e / TJ Fuel Combusted	1.048
Still Gas	3.72%	0.59	93 tons CO ₂ e / TJ Fuel Combusted	101 tons CO ₂ e / TJ Fuel Combusted	110 tons CO ₂ e / TJ Fuel Combusted	1.092
Residual Fuel Oil	1.70%	0.00	105 tons CO ₂ e / TJ Fuel Combusted	146 tons CO ₂ e / TJ Fuel Combusted	121 tons CO ₂ e / TJ Fuel Combusted	1.191
Asphalt*	1.71%	1.00		--		--
Other Oils*	0.56%	1.00		--		--
Lubricants*	0.64%	1.00		--		--
Other*	5.16%	1.00		--		--

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End Notes

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- 2013. Available at: <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>. ES-4. Carbon dioxide equivalent (CO₂e) is the standard measure of greenhouse gas emissions. The measure accounts for the different global warming potentials for different greenhouse gases such as N₂O, CH₄, and CO₂.
- ⁵ Ibid at ES-18-19 (85% of total U.S. GHG emissions in 2013 were produced by fossil fuel combustion).
- ⁶ Ibid at ES-4. Carbon dioxide equivalent (CO₂e) is the standard measure of greenhouse gas emissions. The measure accounts for the different global warming potentials for different greenhouse gases such as N₂O, CH₄, and CO₂.
- ⁷ Climate Action Tracker is a joint project of Climate Analytics, Ecofys, Potsdam Institute for Climate Impact Research, and the NewClimate Institute.
- ⁸ Climate Action Tracker. 2015. Are governments doing their “fair share”? New method assesses climate action. 27 March 2015. See Figures 2 and 3.
- ⁹ Stratus Consulting. 2014. Greenhouse Gas Emissions from Fossil Energy Extracted from Federal Lands and Waters. Available at: <http://wilderness.org/sites/default/files/FINAL%20STRATUS%20REPORT.pdf>
- ¹⁰ Heede, Rick. 2015. Memorandum to Dunkiel Saunders and Friends of The Earth. Climate Accountability Institute. Available at: http://webiva-downton.s3.amazonaws.com/877/3a/7/5721/Exhibit_1-1_ONRR_ProdEmissions_Heede_7May15.pdf
- ¹¹ A portion of unleased federal fossil fuel resources are precluded from future leasing by statutory restriction, such as being located within a designated wilderness area. These were accounted for by excluding categories 1 (no leasing by Executive Order) and 2 (no leasing by administrative reason) from Energy Policy and Conservation Lands (EPCA).
- ¹² U.S. Environmental Protection Agency. 2015. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013. Available at: <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>. ES-4.
- ¹³ Research by the World Resources Institute (WRI) 2013 and NREL (2014) suggest that there are no differences between shale and conventional natural gas based on meta-analyses of prior research, although NREL notes that better methane measurements are needed to improve the accuracy of upstream emissions and leakage issues with shale gas.
- ¹⁴ DOE/BLM 2012. United States Department of Energy, United States Department of the Interior, Bureau of Land Management. “Assessment of Plans and Progress on US Bureau of Land Management Oil Shale RD&D Leases in the United States.” http://energy.gov/sites/prod/files/2013/04/f0/BLM_Final.pdf
- ¹⁵ USGS 2006
- ¹⁶ BLM ROD 2013
- ¹⁷ AAPG 2013.
- ¹⁸ EIA 2014d
- ¹⁹ EIA 2013b.
- ²⁰ EIA 2014e.
- ²¹ Brandt, A. 2011. Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries. Report, January 18, 2011.
- ²² Deru and Torcellini’s 2007 technical paper Source Energy and Emission Factors for Energy Use in Buildings.
- ²³ EIA 2015b.
- ²⁴ EIA 2015b.
- ²⁵ EIA 2014e.
- ²⁶ Deru and Torcellini, 2007.
- ²⁷ Deru and Torcellini, 2007.
- ²⁸ Herweyer and Gupta, 2008.
- ²⁹ This is the average of Jacobs 2009, TIAX 2009, and NETL 2008.
- ³⁰ Burnham, et al. 2012.
- ³¹ This is the average of Jacobs 2009, TIAX 2009, and NETL 2008, 2009.
- ³² NETL 2008, 2009
- ³³ NETL 2008, 2009
- ³⁴ NETL 2008, 2009.
- ³⁵ EIA, 2014a.
- ³⁶ Burnham et al., 2012.
- ³⁷ EPA, 2015.
- ³⁸ Johnson, 2010.

Exhibit 6

Fact Sheet: Social Cost of Carbon

Background

EPA and other federal agencies use the social cost of carbon (SCC) to estimate the climate benefits of rulemakings. The SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO₂) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO₂ reduction).

The SCC is meant to be a comprehensive estimate of climate change damages and includes, among other things, changes in net agricultural productivity, human health, and property damages from increased flood risk. However, it does not currently include all important damages. As noted by the [IPCC Fourth Assessment Report](#), it is “very likely that [the SCC] underestimates” the damages. The models used to develop SCC estimates do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research. Nonetheless, the SCC is a useful measure to assess the benefits of CO₂ reductions.

The timing of the emission release (or reduction) is key to estimation of the SCC, which is based on a present value calculation. The integrated assessment models first estimate damages occurring after the emission release and into the future, often as far out as the year 2300. The models then discount the value of those damages over the entire time span back to present value to arrive at the SCC. For example, the SCC for the year 2020 represents the present value of climate change damages that occur between the years 2020 and 2300 (assuming 2300 is the final year of the model run); these damages are associated with the release of one ton of carbon dioxide in the year 2020. The SCC will vary based on the year of emissions for multiple reasons. In model runs where the last year is fixed (e.g., 2300), the time span covered in the present value calculation will be smaller for later emission years—the SCC in 2050 will include 40 fewer years of damages than the 2010 SCC estimates. This modeling choice—selection of a fixed end year—will place downward pressure on the SCC estimates for later emission years. Alternatively, the SCC should increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater levels of climatic change.

One of the most important factors influencing SCC estimates is the discount rate. A large portion of climate change damages are expected to occur many decades into the future and the present value of those damages (the value at present of damages that occur in the future) is highly dependent on the discount rate. To understand the effect that the discount rate has on present value calculations, consider the following example. Let’s say that you have been promised that in 50 years you will receive \$1 billion. In “present value” terms, that sum of money is worth \$291 million today with a 2.5 percent discount rate. In other words, if you invested \$291 million today at 2.5 percent and let it compound, it would be worth \$1 billion in 50 years. A higher

discount rate of 3 percent would decrease the value today to \$228 million, and the value would be even lower—\$87 million-- with a 5 percent rate. This effect is even more pronounced when looking at the present value of damages further out in time. The value of \$1 billion in 100 years is \$85 million, \$52 million, and \$8 million, for discount rates of 2.5 percent, 3 percent, and 5 percent, respectively. Similarly, the selection of a 2.5 percent discount rate would result in higher SCC estimates than would the selection of 3 and 5 percent rates, all else equal.

Process Used to Develop the SCC

An interagency working group was convened by the Council of Economic Advisers and the Office of Management and Budget in 2009-2010 to design an SCC modeling exercise and develop estimates for use in rulemakings. The interagency group was comprised of scientific and economic experts from the White House and federal agencies, including: Council on Environmental Quality, National Economic Council, Office of Energy and Climate Change, and Office of Science and Technology Policy, EPA, and the Departments of Agriculture, Commerce, Energy, Transportation, and Treasury. The interagency group identified a variety of assumptions, which EPA then used to estimate the SCC using three integrated assessment models, which each combine climate processes, economic growth, and interactions between the two in a single modeling framework.

SCC Values

The 2009-2010 interagency group developed a set of four SCC estimates for use in regulatory analyses. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent. SCC estimates based on several discount rates are included because the literature shows that the SCC is highly sensitive to the discount rate and because no consensus exists on the appropriate rate to use for analyses spanning multiple generations. The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate, and is intended to represent the potential for higher-than-average damages. See the [SCC Technical Support Document](#) (PDF, 51pp, 848K) for a complete discussion about the methodology and resulting estimates.

The interagency group recently updated these estimates, using new versions of each integrated assessment model and published them in May 2013. The 2013 interagency process did not revisit the 2009-2010 interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios or equilibrium climate sensitivity). Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and as used in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those developed in the 2009-2010 modeling exercise. The four 2020 SCC estimates reported in the 2010 interagency group were \$7, \$28, \$44 and \$86 per metric ton (2011\$). The corresponding four updated SCC estimates for 2020 are \$13, \$46, \$68, and \$137 per metric ton (2011\$). The [May 2013 SCC Technical Support Document](#) (PDF, 22pp, 780K) provides a detailed discussion of the model updates relevant to these estimates.

The table below summarizes the four SCC estimates in certain years.

Social Cost of CO₂, 2015-2050 ^a (in 2011 Dollars)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95 th percentile
2015	\$12	\$39	\$61	\$116
2020	\$13	\$46	\$68	\$137
2025	\$15	\$50	\$74	\$153
2030	\$17	\$55	\$80	\$170
2035	\$20	\$60	\$85	\$187
2040	\$22	\$65	\$92	\$204
2045	\$26	\$70	\$98	\$220
2050	\$28	\$76	\$104	\$235

^a The SCC values are dollar-year and emissions-year specific.

Examples of SCC Applications to Rulemakings

EPA has used the SCC to analyze the carbon dioxide impacts of various rulemakings since the interagency group first published estimates in 2010. Examples of these rulemakings include:

- The Joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards (2012-2016)
- Amendments to the National Emission Standards for Hazardous Air Pollutants and New Source Performance Standards (NSPS) for the Portland Cement Manufacturing Industry
- Regulatory Impact Results for the Reconsideration Proposal for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources
- Proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) for Mercury Emissions from Mercury Cell Chlor Alkali Plants
- Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units Standards
- Final Mercury and Air Toxics Standards
- Joint EPA/Department of Transportation Rulemaking to establish Medium- and Heavy - Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards
- Proposed Carbon Pollution Standard for Future Power Plants
- Joint EPA/Department of Transportation Rulemaking to establish 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards

Limitations of SCC

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Additional details are discussed in the 2010¹ and 2013² SCC Technical Support Documents.

Next Steps

The U.S. government committed to updating the current estimates as the science and economic understanding of climate change and its impacts on society improves over time. For example, EPA and Department of Energy also hosted a [series of workshops](#) to inform SCC development. The first workshop focused on conceptual and methodological issues related to integrated assessment modeling and valuing climate change impacts, along with methods of incorporating these estimates into policy analysis. The second workshop reviewed research on estimating impacts and valuing damages on a sectoral basis. Papers based on the presentations from both workshops were published in a special issue of *Climatic Change* (April 2013). In addition, EPA funded a workshop on discounting in September 2011 that invited world-recognized experts to discuss how the benefits and costs of regulations should be discounted for projects with long horizons. In particular, it explored what principles should be used to determine the rates at which to discount the costs and benefits of regulatory programs when costs and benefits extend over very long horizons.

EPA and other agencies continue to engage in research on modeling and valuation of climate impacts to improve these estimates.

¹ See <http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf>

² See <http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf>

Exhibit 7

**Technical Support Document: -
Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -
Under Executive Order 12866 -**

Interagency Working Group on Social Cost of Carbon, United States Government

With participation by

Council of Economic Advisers
Council on Environmental Quality
Department of Agriculture
Department of Commerce
Department of Energy
Department of Transportation
Environmental Protection Agency
National Economic Council
Office of Management and Budget
Office of Science and Technology Policy
Department of the Treasury

May 2013

Executive Summary

Under Executive Order 12866, agencies are required, to the extent permitted by law, “to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.” The purpose of the “social cost of carbon” (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO₂) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The interagency process that developed the original U.S. government’s SCC estimates is described in the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010). Through that process the interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

While acknowledging the continued limitations of the approach taken by the interagency group in 2010, this document provides an update of the SCC estimates based on new versions of each IAM (DICE, PAGE, and FUND). It does not revisit other interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity). Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD. By way of comparison, the four 2020 SCC estimates reported in the 2010 TSD were \$7, \$26, \$42 and \$81 (2007\$). The corresponding four updated SCC estimates for 2020 are \$12, \$43, \$65, and \$129 (2007\$). The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The SCC estimates vary by year, and the following table summarizes the revised SCC estimates from 2010 through 2050.

Revised Social Cost of CO₂, 2010 – 2050 (in 2007 dollars per metric ton of CO₂)

Discount Rate	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

I. Purpose

The purpose of this document is to update the schedule of social cost of carbon (SCC) estimates from the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010).¹ E.O. 13563 commits the Administration to regulatory decision making “based on the best available science.”² Additionally, the interagency group recommended in 2010 that the SCC estimates be revisited on a regular basis or as model updates that reflect the growing body of scientific and economic knowledge become available.³ New versions of the three integrated assessment models used by the U.S. government to estimate the SCC (DICE, FUND, and PAGE), are now available and have been published in the peer reviewed literature. While acknowledging the continued limitations of the approach taken by the interagency group in 2010 (documented in the original 2010 TSD), this document provides an update of the SCC estimates based on the latest peer-reviewed version of the models, replacing model versions that were developed up to ten years ago in a rapidly evolving field. It does not revisit other assumptions with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity. Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature. The agencies participating in the interagency working group continue to investigate potential improvements to the way in which economic damages associated with changes in CO₂ emissions are quantified.

Section II summarizes the major updates relevant to SCC estimation that are contained in the new versions of the integrated assessment models released since the 2010 interagency report. Section III presents the updated schedule of SCC estimates for 2010 – 2050 based on these versions of the models. Section IV provides a discussion of other model limitations and research gaps.

II. Summary of Model Updates

This section briefly summarizes changes to the most recent versions of the three integrated assessment models (IAMs) used by the interagency group in 2010. We focus on describing those model updates that are relevant to estimating the social cost of carbon, as summarized in Table 1. For example, both the DICE and PAGE models now include an explicit representation of sea level rise damages. Other revisions to PAGE include: updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages. The DICE model’s simple carbon cycle has been updated to be more consistent with a more complex climate model. The FUND model includes updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of

¹ In this document, we present all values of the SCC as the cost per metric ton of CO₂ emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO₂ and the mass of carbon is 3.67 (the molecular weight of CO₂ divided by the molecular weight of carbon = $44/12 = 3.67$).

² http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866/eo13563_01182011.pdf

³ See p. 1, 3, 4, 29, and 33 (Interagency Working Group on Social Cost of Carbon 2010).

methane emissions. Changes made to parts of the models that are superseded by the interagency working group’s modeling assumptions – regarding equilibrium climate sensitivity, discounting, and socioeconomic variables – are not discussed here but can be found in the references provided in each section below.

Table 1: Summary of Key Model Revisions Relevant to the Interagency SCC

IAM	Version used in 2010 Interagency Analysis	New Version	Key changes relevant to interagency SCC
DICE	2007	2010	Updated calibration of the carbon cycle model and explicit representation of sea level rise (SLR) and associated damages.
FUND	3.5 (2009)	3.8 (2012)	Updated damage functions for space heating, SLR, agricultural impacts, changes to transient response of temperature to buildup of GHG concentrations, and inclusion of indirect climate effects of methane.
PAGE	2002	2009	Explicit representation of SLR damages, revisions to damage function to ensure damages do not exceed 100% of GDP, change in regional scaling of damages, revised treatment of potential abrupt damages, and updated adaptation assumptions.

A. DICE

DICE 2010 includes a number of changes over the previous 2007 version used in the 2010 interagency report. The model changes that are relevant for the SCC estimates developed by the interagency working group include: 1) updated parameter values for the carbon cycle model, 2) an explicit representation of sea level dynamics, and 3) a re-calibrated damage function that includes an explicit representation of economic damages from sea level rise. Changes were also made to other parts of the DICE model—including the equilibrium climate sensitivity parameter, the rate of change of total factor productivity, and the elasticity of the marginal utility of consumption—but these components of DICE are superseded by the interagency working group’s assumptions and so will not be discussed here. More details on DICE2007 can be found in Nordhaus (2008) and on DICE2010 in Nordhaus (2010). The DICE2010 model and documentation is also available for download from the homepage of William Nordhaus.

Carbon Cycle Parameters

DICE uses a three-box model of carbon stocks and flows to represent the accumulation and transfer of carbon among the atmosphere, the shallow ocean and terrestrial biosphere, and the deep ocean. These parameters are “calibrated to match the carbon cycle in the Model for the Assessment of Greenhouse

Gas Induced Climate Change (MAGICC)” (Nordhaus 2008 p 44).⁴ Carbon cycle transfer coefficient values in DICE2010 are based on re-calibration of the model to match the newer 2009 version of MAGICC (Nordhaus 2010 p 2). For example, in DICE2010, in each decade, 12 percent of the carbon in the atmosphere is transferred to the shallow ocean, 4.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 94.8 percent remains in the shallow ocean, and 0.5 percent is transferred to the deep ocean. For comparison, in DICE 2007, 18.9 percent of the carbon in the atmosphere is transferred to the shallow ocean each decade, 9.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 85.3 percent remains in the shallow ocean, and 5 percent is transferred to the deep ocean.

The implication of these changes for DICE2010 is in general a weakening of the ocean as a carbon sink and therefore a higher concentration of carbon in the atmosphere than in DICE2007, for a given path of emissions. All else equal, these changes will generally increase the level of warming and therefore the SCC estimates in DICE2010 relative to those from DICE2007.

Sea Level Dynamics

A new feature of DICE2010 is an explicit representation of the dynamics of the global average sea level anomaly to be used in the updated damage function (discussed below). This section contains a brief description of the sea level rise (SLR) module; a more detailed description can be found on the model developer’s website.⁵ The average global sea level anomaly is modeled as the sum of four terms that represent contributions from: 1) thermal expansion of the oceans, 2) melting of glaciers and small ice caps, 3) melting of the Greenland ice sheet, and 4) melting of the Antarctic ice sheet.

The parameters of the four components of the SLR module are calibrated to match consensus results from the IPCC’s Fourth Assessment Report (AR4).⁶ The rise in sea level from thermal expansion in each time period (decade) is 2 percent of the difference between the sea level in the previous period and the long run equilibrium sea level, which is 0.5 meters per degree Celsius (°C) above the average global temperature in 1900. The rise in sea level from the melting of glaciers and small ice caps occurs at a rate of 0.008 meters per decade per °C above the average global temperature in 1900.

The contribution to sea level rise from melting of the Greenland ice sheet is more complex. The equilibrium contribution to SLR is 0 meters for temperature anomalies less than 1 °C and increases linearly from 0 meters to a maximum of 7.3 meters for temperature anomalies between 1 °C and 3.5 °C. The contribution to SLR in each period is proportional to the difference between the previous period’s sea level anomaly and the equilibrium sea level anomaly, where the constant of proportionality increases with the temperature anomaly in the current period.

⁴ MAGICC is a simple climate model initially developed by the U.S. National Center for Atmospheric Research that has been used heavily by the Intergovernmental Panel on Climate Change (IPCC) to emulate projections from more sophisticated state of the art earth system simulation models (Randall et al. 2007).

⁵ Documentation on the new sea level rise module of DICE is available on William Nordhaus’ website at: http://nordhaus.econ.yale.edu/documents/SLR_021910.pdf.

⁶ For a review of post-IPCC AR4 research on sea level rise, see Nicholls et al. (2011) and NAS (2011).

The contribution to SLR from the melting of the Antarctic ice sheet is -0.001 meters per decade when the temperature anomaly is below 3 °C and increases linearly between 3 °C and 6 °C to a maximum rate of 0.025 meters per decade at a temperature anomaly of 6 °C.

Re-calibrated Damage Function

Economic damages from climate change in the DICE model are represented by a fractional loss of gross economic output in each period. A portion of the remaining economic output in each period (net of climate change damages) is consumed and the remainder is invested in the physical capital stock to support future economic production, so each period's climate damages will reduce consumption in that period and in all future periods due to the lost investment. The fraction of output in each period that is lost due to climate change impacts is represented as one minus a fraction, which is one divided by a quadratic function of the temperature anomaly, producing a sigmoid ("S"-shaped) function.⁷ The loss function in DICE2010 has been expanded by adding a quadratic function of SLR to the quadratic function of temperature. In DICE2010 the temperature anomaly coefficients have been recalibrated to avoid double-counting damages from sea level rise that were implicitly included in these parameters in DICE2007.

The aggregate damages in DICE2010 are illustrated by Nordhaus (2010 p 3), who notes that "...damages in the uncontrolled (baseline) [i.e., reference] case ... in 2095 are \$12 trillion, or 2.8 percent of global output, for a global temperature increase of 3.4 °C above 1900 levels." This compares to a loss of 3.2 percent of global output at 3.4 °C in DICE2007. However, in DICE2010, annual damages are lower in most of the early periods of the modeling horizon but higher in later periods than would be calculated using the DICE2007 damage function. Specifically, the percent difference between damages in the base run of DICE2010 and those that would be calculated using the DICE2007 damage function starts at +7 percent in 2005, decreases to a low of -14 percent in 2065, then continuously increases to +20 percent by 2300 (the end of the interagency analysis time horizon), and to +160 percent by the end of the model time horizon in 2595. The large increases in the far future years of the time horizon are due to the permanence associated with damages from sea level rise, along with the assumption that the sea level is projected to continue to rise long after the global average temperature begins to decrease. The changes to the loss function generally decrease the interagency working group SCC estimates slightly given that relative increases in damages in later periods are discounted more heavily, all else equal.

B. FUND

FUND version 3.8 includes a number of changes over the previous version 3.5 (Narita et al. 2010) used in the 2010 interagency report. Documentation supporting FUND and the model's source code for all versions of the model is available from the model authors.⁸ Notable changes, due to their impact on the

⁷ The model and documentation, including formulas, are available on the author's webpage at <http://www.econ.yale.edu/~nordhaus/homepage/RICEmodels.htm>.

⁸ <http://www.fund-model.org/>. This report uses version 3.8 of the FUND model, which represents a modest update to the most recent version of the model to appear in the literature (version 3.7) (Anthoff and Tol, 2013). For the purpose of computing the SCC, the relevant changes (between 3.7 to 3.8) are associated with improving

SCC estimates, are adjustments to the space heating, agriculture, and sea level rise damage functions in addition to changes to the temperature response function and the inclusion of indirect effects from methane emissions.⁹ We discuss each of these in turn.

Space Heating

In FUND, the damages associated with the change in energy needs for space heating are based on the estimated impact due to one degree of warming. These baseline damages are scaled based on the forecasted temperature anomaly's deviation from the one degree benchmark and adjusted for changes in vulnerability due to economic and energy efficiency growth. In FUND 3.5, the function that scales the base year damages adjusted for vulnerability allows for the possibility that in some simulations the benefits associated with reduced heating needs may be an unbounded convex function of the temperature anomaly. In FUND 3.8, the form of the scaling has been modified to ensure that the function is everywhere concave and that there will exist an upper bound on the benefits a region may receive from reduced space heating needs. The new formulation approaches a value of two in the limit of large temperature anomalies, or in other words, assuming no decrease in vulnerability, the reduced expenditures on space heating at any level of warming will not exceed two times the reductions experienced at one degree of warming. Since the reduced need for space heating represents a benefit of climate change in the model, or a negative damage, this change will increase the estimated SCC. This update accounts for a significant portion of the difference in the expected SCC estimates reported by the two versions of the model when run probabilistically.

Sea Level Rise and Land Loss

The FUND model explicitly includes damages associated with the inundation of dry land due to sea level rise. The amount of land lost within a region is dependent upon the proportion of the coastline being protected by adequate sea walls and the amount of sea level rise. In FUND 3.5 the function defining the potential land lost in a given year due to sea level rise is linear in the rate of sea level rise for that year. This assumption implicitly assumes that all regions are well represented by a homogeneous coastline in length and a constant uniform slope moving inland. In FUND 3.8 the function defining the potential land lost has been changed to be a convex function of sea level rise, thereby assuming that the slope of the shore line increases moving inland. The effect of this change is to typically reduce the vulnerability of some regions to sea level rise based land loss, thereby lowering the expected SCC estimate.¹⁰

Agriculture

consistency with IPCC AR4 by adjusting the atmospheric lifetimes of CH₄ and N₂O and incorporating the indirect forcing effects of CH₄, along with making minor stability improvements in the sea wall construction algorithm.

⁹ The other damage sectors (water resources, space cooling, land loss, migration, ecosystems, human health, and extreme weather) were not significantly updated.

¹⁰ For stability purposes this report also uses an update to the model which assumes that regional coastal protection measures will be built to protect the most valuable land first, such that the marginal benefits of coastal protection is decreasing in the level of protection following Fankhauser (1995).

In FUND, the damages associated with the agricultural sector are measured as proportional to the sector's value. The fraction is bounded from above by one and is made up of three additive components that represent the effects from carbon fertilization, the rate of temperature change, and the level of the temperature anomaly. In both FUND 3.5 and FUND 3.8, the fraction of the sector's value lost due to the level of the temperature anomaly is modeled as a quadratic function with an intercept of zero. In FUND 3.5, the coefficients of this loss function are modeled as the ratio of two random normal variables. This specification had the potential for unintended extreme behavior as draws from the parameter in the denominator approached zero or went negative. In FUND 3.8, the coefficients are drawn directly from truncated normal distributions so that they remain in the range $[0, \infty)$ and $(-\infty, 0]$, respectively, ensuring the correct sign and eliminating the potential for divide by zero errors. The means for the new distributions are set equal to the ratio of the means from the normal distributions used in the previous version. In general the impact of this change has been to decrease the range of the distribution while spreading out the distributions' mass over the remaining range relative to the previous version. The net effect of this change on the SCC estimates is difficult to predict.

Transient Temperature Response

The temperature response model translates changes in global levels of radiative forcing into the current expected temperature anomaly. In FUND, a given year's increase in the temperature anomaly is based on a mean reverting function where the mean equals the equilibrium temperature anomaly that would eventually be reached if that year's level of radiative forcing were sustained. The rate of mean reversion defines the rate at which the transient temperature approaches the equilibrium. In FUND 3.5, the rate of temperature response is defined as a decreasing linear function of equilibrium climate sensitivity to capture the fact that the progressive heat uptake of the deep ocean causes the rate to slow at higher values of the equilibrium climate sensitivity. In FUND 3.8, the rate of temperature response has been updated to a quadratic function of the equilibrium climate sensitivity. This change reduces the sensitivity of the rate of temperature response to the level of the equilibrium climate sensitivity, a relationship first noted by Hansen et al. (1985) based on the heat uptake of the deep ocean. Therefore in FUND 3.8, the temperature response will typically be faster than in the previous version. The overall effect of this change is likely to increase estimates of the SCC as higher temperatures are reached during the timeframe analyzed and as the same damages experienced in the previous version of the model are now experienced earlier and therefore discounted less.

Methane

The IPCC AR4 notes a series of indirect effects of methane emissions, and has developed methods for proxying such effects when computing the global warming potential of methane (Forster et al. 2007). FUND 3.8 now includes the same methods for incorporating the indirect effects of methane emissions. Specifically, the average atmospheric lifetime of methane has been set to 12 years to account for the feedback of methane emissions on its own lifetime. The radiative forcing associated with atmospheric methane has also been increased by 40% to account for its net impact on ozone production and stratospheric water vapor. All else equal, the effect of this increased radiative forcing will be to increase the estimated SCC values, due to greater projected temperature anomaly.

C. PAGE

PAGE09 (Hope 2013) includes a number of changes from PAGE2002, the version used in the 2010 SCC interagency report. The changes that most directly affect the SCC estimates include: explicitly modeling the impacts from sea level rise, revisions to the damage function to ensure damages are constrained by GDP, a change in the regional scaling of damages, a revised treatment for the probability of a discontinuity within the damage function, and revised assumptions on adaptation. The model also includes revisions to the carbon cycle feedback and the calculation of regional temperatures.¹¹ More details on PAGE09 can be found in Hope (2011a, 2011b, 2011c). A description of PAGE2002 can be found in Hope (2006).

Sea Level Rise

While PAGE2002 aggregates all damages into two categories – economic and non-economic impacts –, PAGE09 adds a third explicit category: damages from sea level rise. In the previous version of the model, damages from sea level rise were subsumed by the other damage categories. In PAGE09 sea level damages increase less than linearly with sea level under the assumption that land, people, and GDP are more concentrated in low-lying shoreline areas. Damages from the economic and non-economic sector were adjusted to account for the introduction of this new category.

Revised Damage Function to Account for Saturation

In PAGE09, small initial economic and non-economic benefits (negative damages) are modeled for small temperature increases, but all regions eventually experience economic damages from climate change, where damages are the sum of additively separable polynomial functions of temperature and sea level rise. Damages transition from this polynomial function to a logistic path once they exceed a certain proportion of remaining Gross Domestic Product (GDP) to ensure that damages do not exceed 100 percent of GDP. This differs from PAGE2002, which allowed Eastern Europe to potentially experience large benefits from temperature increases, and which also did not bound the possible damages that could be experienced.

Regional Scaling Factors

As in the previous version of PAGE, the PAGE09 model calculates the damages for the European Union (EU) and then, assumes that damages for other regions are proportional based on a given scaling factor. The scaling factor in PAGE09 is based on the length of a region's coastline relative to the EU (Hope 2011b). Because of the long coastline in the EU, other regions are, on average, less vulnerable than the EU for the same sea level and temperature increase, but all regions have a positive scaling factor. PAGE2002 based its scaling factors on four studies reported in the IPCC's third assessment report, and allowed for benefits from temperature increase in Eastern Europe, smaller impacts in developed countries, and higher damages in developing countries.

¹¹ Because several changes in the PAGE model are structural (e.g., the addition of sea level rise and treatment of discontinuity), it is not possible to assess the direct impact of each change on the SCC in isolation as done for the other two models above.

Probability of a Discontinuity

In PAGE2002, the damages associated with a “discontinuity” (nonlinear extreme event) were modeled as an expected value. Specifically, a stochastic probability of a discontinuity was multiplied by the damages associated with a discontinuity to obtain an expected value, and this was added to the economic and non-economic impacts. That is, additional damages from an extreme event, such as extreme melting of the Greenland ice sheet, were multiplied by the probability of the event occurring and added to the damage estimate. In PAGE09, the probability of discontinuity is treated as a discrete event for each year in the model. The damages for each model run are estimated either with or without a discontinuity occurring, rather than as an expected value. A large-scale discontinuity becomes possible when the temperature rises beyond some threshold value between 2 and 4°C. The probability that a discontinuity will occur beyond this threshold then increases by between 10 and 30 percent for every 1°C rise in temperature beyond the threshold. If a discontinuity occurs, the EU loses an additional 5 to 25 percent of its GDP (drawn from a triangular distribution with a mean of 15 percent) in addition to other damages, and other regions lose an amount determined by the regional scaling factor. The threshold value for a possible discontinuity is lower than in PAGE2002, while the rate at which the probability of a discontinuity increases with the temperature anomaly and the damages that result from a discontinuity are both higher than in PAGE2002. The model assumes that only one discontinuity can occur and that the impact is phased in over a period of time, but once it occurs, its effect is permanent.

Adaptation

As in PAGE2002, adaptation is available to help mitigate any climate change impacts that occur. In PAGE this adaptation is the same regardless of the temperature change or sea level rise and is therefore akin to what is more commonly considered a reduction in vulnerability. It is modeled by reducing the damages by some percentage. PAGE09 assumes a smaller decrease in vulnerability than the previous version of the model and assumes that it will take longer for this change in vulnerability to be realized. In the aggregated economic sector, at the time of full implementation, this adaptation will mitigate all damages up to a temperature increase of 1°C, and for temperature anomalies between 1°C and 2°C, it will reduce damages by 15-30 percent (depending on the region). However, it takes 20 years to fully implement this adaptation. In PAGE2002, adaptation was assumed to reduce economic sector damages up to 2°C by 50-90 percent after 20 years. Beyond 2°C, no adaptation is assumed to be available to mitigate the impacts of climate change. For the non-economic sector, in PAGE09 adaptation is available to reduce 15 percent of the damages due to a temperature increase between 0°C and 2°C and is assumed to take 40 years to fully implement, instead of 25 percent of the damages over 20 years assumed in PAGE2002. Similarly, adaptation is assumed to alleviate 25-50 percent of the damages from the first 0.20 to 0.25 meters of sea level rise but is assumed to be ineffective thereafter. Hope (2011c) estimates that the less optimistic assumptions regarding the ability to offset impacts of temperature and sea level rise via adaptation increase the SCC by approximately 30 percent.

Other Noteworthy Changes

Two other changes in the model are worth noting. There is a change in the way the model accounts for decreased CO₂ absorption on land and in the ocean as temperature rises. PAGE09 introduces a linear feedback from global mean temperature to the percentage gain in the excess concentration of CO₂, capped at a maximum level. In PAGE2002, an additional amount was added to the CO₂ emissions each period to account for a decrease in ocean absorption and a loss of soil carbon. Also updated is the method by which the average global and annual temperature anomaly is downscaled to determine annual average regional temperature anomalies to be used in the regional damage functions. In PAGE2002, the scaling was determined solely based on regional difference in emissions of sulfate aerosols. In PAGE09, this regional temperature anomaly is further adjusted using an additive factor that is based on the average absolute latitude of a region relative to the area weighted average absolute latitude of the Earth's landmass, to capture relatively greater changes in temperature forecast to be experienced at higher latitudes.

III. Revised SCC Estimates

The updated versions of the three integrated assessment models were run using the same methodology detailed in the 2010 TSD (Interagency Working Group on Social Cost of Carbon 2010). The approach along with the inputs for the socioeconomic emissions scenarios, equilibrium climate sensitivity distribution, and discount rate remains the same. This includes the five reference scenarios based on the EMF-22 modeling exercise, the Roe and Baker equilibrium climate sensitivity distribution calibrated to the IPCC AR4, and three constant discount rates of 2.5, 3, and 5 percent.

As was previously the case, the use of three models, three discount rates, and five scenarios produces 45 separate distributions for the global SCC. The approach laid out in the 2010 TSD applied equal weight to each model and socioeconomic scenario in order to reduce the dimensionality down to three separate distributions representative of the three discount rates. The interagency group selected four values from these distributions for use in regulatory analysis. Three values are based on the average SCC across models and socio-economic-emissions scenarios at the 2.5, 3, and 5 percent discount rates, respectively. The fourth value was chosen to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, the 95th percentile of the SCC estimates at a 3 percent discount rate was chosen. (A detailed set of percentiles by model and scenario combination and additional summary statistics for the 2020 values is available in the Appendix.) As noted in the 2010 TSD, "the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate" (Interagency Working Group on Social Cost of Carbon 2010, p. 25). However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance and value of including all four SCC values.

Table 2 shows the four selected SCC estimates in five year increments from 2010 to 2050. Values for 2010, 2020, 2030, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per

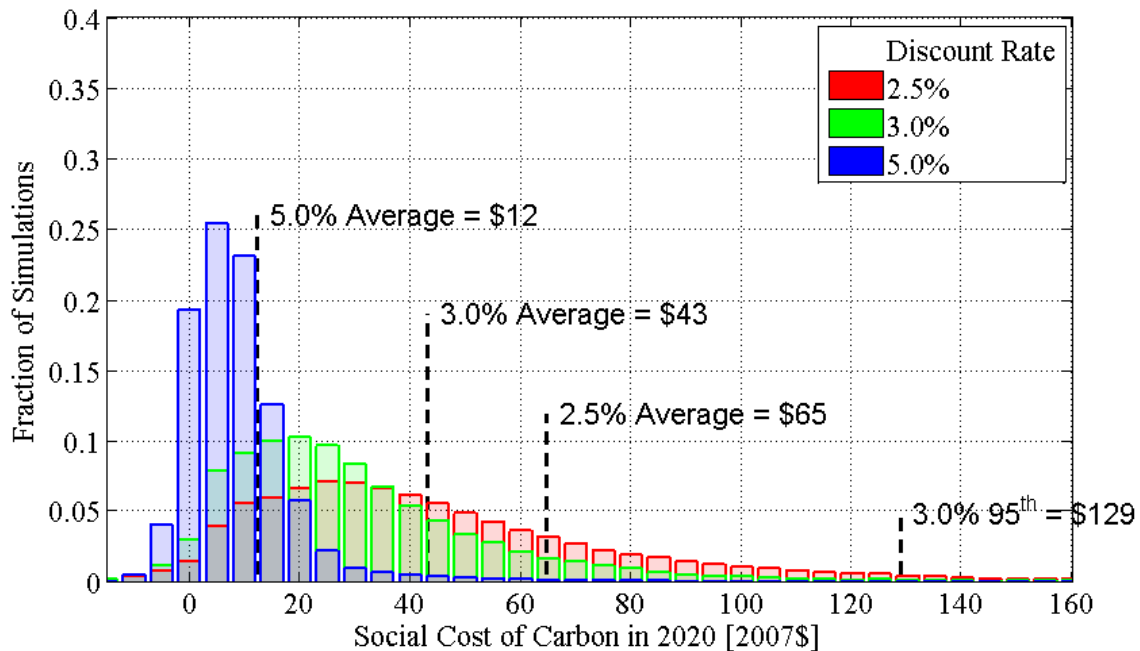
model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated using linear interpolation. The full set of revised annual SCC estimates between 2010 and 2050 is reported in the Appendix.

Table 2: Revised Social Cost of CO₂, 2010 – 2050 (in 2007 dollars per metric ton of CO₂)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD due to the changes to the models outlined in the previous section. By way of comparison, the 2020 SCC estimates reported in the original TSD were \$7, \$26, \$42 and \$81 (2007\$) (Interagency Working Group on Social Cost of Carbon 2010). Figure 1 illustrates where the four SCC values for 2020 fall within the full distribution for each discount rate based on the combined set of runs for each model and scenario (150,000 estimates in total for each discount rate). In general, the distributions are skewed to the right and have long tails. The Figure also shows that the lower the discount rate, the longer the right tail of the distribution.

Figure 1: Distribution of SCC Estimates for 2020 (in 2007\$ per metric ton CO₂)



As was the case in the 2010 TSD, the SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. The approach taken by the interagency group is to compute the cost of a marginal ton emitted in the future by running the models for a set of perturbation years out to 2050. Table 3 illustrates how the growth rate for these four SCC estimates varies over time.

Table 3: Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Growth Rate (%)	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010-2020	1.2%	3.2%	2.4%	4.3%
2020-2030	3.4%	2.1%	1.7%	2.4%
2030-2040	3.0%	1.8%	1.5%	2.0%
2040-2050	2.6%	1.6%	1.3%	1.5%

The future monetized value of emission reductions in each year (the SCC in year t multiplied by the change in emissions in year t) must be discounted to the present to determine its total net present value for use in regulatory analysis. As previously discussed in the 2010 TSD, damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency – i.e., future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate.

Under current OMB guidance contained in Circular A-4, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around

the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. For additional discussion, see the 2010 TSD.

IV. Other Model Limitations and Research Gaps

The 2010 interagency SCC TSD discusses a number of important limitations for which additional research is needed. In particular, the document highlights the need to improve the quantification of both non-catastrophic and catastrophic damages, the treatment of adaptation and technological change, and the way in which inter-regional and inter-sectoral linkages are modeled. While the new version of the models discussed above offer some improvements in these areas, further work remains warranted. The 2010 TSD also discusses the need to more carefully assess the implications of risk aversion for SCC estimation as well as the inability to perfectly substitute between climate and non-climate goods at higher temperature increases, both of which have implications for the discount rate used. EPA, DOE, and other agencies continue to engage in research on modeling and valuation of climate impacts that can potentially improve SCC estimation in the future.

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Appendix

Table A1: Annual SCC Values: 2010-2050 (2007\$/metric ton CO₂)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	33	52	90
2011	11	34	54	94
2012	11	35	55	98
2013	11	36	56	102
2014	11	37	57	106
2015	12	38	58	109
2016	12	39	60	113
2017	12	40	61	117
2018	12	41	62	121
2019	12	42	63	125
2020	12	43	65	129
2021	13	44	66	132
2022	13	45	67	135
2023	13	46	68	138
2024	14	47	69	141
2025	14	48	70	144
2026	15	49	71	147
2027	15	49	72	150
2028	15	50	73	153
2029	16	51	74	156
2030	16	52	76	159
2031	17	53	77	163
2032	17	54	78	166
2033	18	55	79	169
2034	18	56	80	172
2035	19	57	81	176
2036	19	58	82	179
2037	20	59	84	182
2038	20	60	85	185
2039	21	61	86	188
2040	21	62	87	192
2041	22	63	88	195
2042	22	64	89	198
2043	23	65	90	200
2044	23	65	91	203
2045	24	66	92	206
2046	24	67	94	209
2047	25	68	95	212
2048	25	69	96	215
2049	26	70	97	218
2050	27	71	98	221

Table A2: 2020 Global SCC Estimates at 2.5 Percent Discount Rate (2007\$/metric ton CO₂)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95 th	99th
Scenario ¹²	PAGE									
IMAGE	6	11	15	27	58	129	139	327	515	991
MERGE	4	6	9	16	34	78	82	196	317	649
MESSAGE	4	8	11	20	42	108	107	278	483	918
MiniCAM Base	5	9	12	22	47	107	113	266	431	872
5th Scenario	2	4	6	11	25	85	68	200	387	955

Scenario	DICE									
IMAGE	25	31	37	47	64	72	92	123	139	161
MERGE	14	18	20	26	36	40	50	65	74	85
MESSAGE	20	24	28	37	51	58	71	95	109	221
MiniCAM Base	20	25	29	38	53	61	76	102	117	135
5th Scenario	17	22	25	33	45	52	65	91	106	126

Scenario	FUND									
IMAGE	-17	-1	5	17	34	44	59	90	113	176
MERGE	-7	2	7	16	30	35	49	72	91	146
MESSAGE	-19	-4	2	12	27	32	46	70	87	135
MiniCAM Base	-9	1	8	18	35	45	59	87	108	172
5th Scenario	-30	-12	-5	6	19	24	35	57	72	108

Table A3: 2020 Global SCC Estimates at 3 Percent Discount Rate (2007\$/metric ton CO₂)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	4	7	10	18	38	91	95	238	385	727
MERGE	2	4	6	11	23	56	58	142	232	481
MESSAGE	3	5	7	13	29	75	74	197	330	641
MiniCAM Base	3	5	8	14	30	73	75	184	300	623
5th Scenario	1	3	4	7	17	58	48	136	264	660

Scenario	DICE									
IMAGE	16	21	24	32	43	48	60	79	90	102
MERGE	10	13	15	19	25	28	35	44	50	58
MESSAGE	14	18	20	26	35	40	49	64	73	83
MiniCAM Base	13	17	20	26	35	39	49	65	73	85
5th Scenario	12	15	17	22	30	34	43	58	67	79

Scenario	FUND									
IMAGE	-14	-3	1	9	20	25	35	54	69	111
MERGE	-8	-1	3	9	18	22	31	47	60	97
MESSAGE	-16	-5	-1	6	16	18	28	43	55	88
MiniCAM Base	-9	-1	3	10	21	27	35	53	67	107
5th Scenario	-22	-10	-5	2	10	13	20	33	42	63

¹² See 2010 TSD for a description of these scenarios.

Table A4: 2020 Global SCC Estimates at 5 Percent Discount Rate (2007\$/metric ton CO₂)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	1	2	2	5	10	28	27	71	123	244
MERGE	1	1	2	3	7	17	17	45	75	153
MESSAGE	1	1	2	4	9	24	22	60	106	216
MiniCAM Base	1	1	2	3	8	21	21	54	94	190
5th Scenario	0	1	1	2	5	18	14	41	78	208

Scenario	DICE									
IMAGE	6	8	9	11	14	15	18	22	25	27
MERGE	4	5	6	7	9	10	12	15	16	18
MESSAGE	6	7	8	10	12	13	16	20	22	25
MiniCAM Base	5	6	7	8	11	12	14	18	20	22
5th Scenario	5	6	6	8	10	11	14	17	19	21

Scenario	FUND									
IMAGE	-9	-5	-3	-1	2	3	6	11	15	25
MERGE	-6	-3	-2	0	3	4	7	12	16	27
MESSAGE	-10	-6	-4	-1	2	2	5	9	13	23
MiniCAM Base	-7	-3	-2	0	3	4	7	11	15	26
5th Scenario	-11	-7	-5	-2	0	0	3	6	8	14

Table A5: Additional Summary Statistics of 2020 Global SCC Estimates

Discount rate:	5.0%				3.0%				2.5%			
Statistic:	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	22	1616	5	32	71	14953	4	22	101	29312	4	23
FUND	3	560	-170	35222	21	22487	-85	18842	36	68055	-46	13105

Exhibit 8

**Technical Support Document: -
Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -
Under Executive Order 12866 -**

Interagency Working Group on Social Cost of Carbon, United States Government

With participation by

Council of Economic Advisers
Council on Environmental Quality
Department of Agriculture
Department of Commerce
Department of Energy
Department of Transportation
Environmental Protection Agency
National Economic Council
Office of Management and Budget
Office of Science and Technology Policy
Department of the Treasury

May 2013

Revised July 2015

See Appendix B for Details on Revision

Executive Summary

Under Executive Order 12866, agencies are required, to the extent permitted by law, “to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.” The purpose of the “social cost of carbon” (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO₂) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The interagency process that developed the original U.S. government’s SCC estimates is described in the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010). Through that process the interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

While acknowledging the continued limitations of the approach taken by the interagency group in 2010, this document provides an update of the SCC estimates based on new versions of each IAM (DICE, PAGE, and FUND). It does not revisit other interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity). Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD. By way of comparison, the four 2020 SCC estimates reported in the 2010 TSD were \$7, \$26, \$42 and \$81 (2007\$). The corresponding four updated SCC estimates for 2020 are \$12, \$43, \$64, and \$128 (2007\$). The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The SCC estimates vary by year, and the following table summarizes the revised SCC estimates from 2010 through 2050.

Revised Social Cost of CO₂, 2010 – 2050 (in 2007 dollars per metric ton of CO₂)

Discount Rate	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

I. Purpose

The purpose of this document is to update the schedule of social cost of carbon (SCC) estimates from the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010).¹ E.O. 13563 commits the Administration to regulatory decision making “based on the best available science.”² Additionally, the interagency group recommended in 2010 that the SCC estimates be revisited on a regular basis or as model updates that reflect the growing body of scientific and economic knowledge become available.³ New versions of the three integrated assessment models used by the U.S. government to estimate the SCC (DICE, FUND, and PAGE), are now available and have been published in the peer reviewed literature. While acknowledging the continued limitations of the approach taken by the interagency group in 2010 (documented in the original 2010 TSD), this document provides an update of the SCC estimates based on the latest peer-reviewed version of the models, replacing model versions that were developed up to ten years ago in a rapidly evolving field. It does not revisit other assumptions with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity. Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature. The agencies participating in the interagency working group continue to investigate potential improvements to the way in which economic damages associated with changes in CO₂ emissions are quantified.

Section II summarizes the major updates relevant to SCC estimation that are contained in the new versions of the integrated assessment models released since the 2010 interagency report. Section III presents the updated schedule of SCC estimates for 2010 – 2050 based on these versions of the models. Section IV provides a discussion of other model limitations and research gaps.

II. Summary of Model Updates

This section briefly summarizes changes to the most recent versions of the three integrated assessment models (IAMs) used by the interagency group in 2010. We focus on describing those model updates that are relevant to estimating the social cost of carbon, as summarized in Table 1. For example, both the DICE and PAGE models now include an explicit representation of sea level rise damages. Other revisions to PAGE include: updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages. The DICE model’s simple carbon cycle has been updated to be more consistent with a more complex climate model. The FUND model includes updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of

¹ In this document, we present all values of the SCC as the cost per metric ton of CO₂ emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO₂ and the mass of carbon is 3.67 (the molecular weight of CO₂ divided by the molecular weight of carbon = $44/12 = 3.67$).

² http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866/eo13563_01182011.pdf

³ See p. 1, 3, 4, 29, and 33 (Interagency Working Group on Social Cost of Carbon 2010).

methane emissions. Changes made to parts of the models that are superseded by the interagency working group’s modeling assumptions – regarding equilibrium climate sensitivity, discounting, and socioeconomic variables – are not discussed here but can be found in the references provided in each section below.

Table 1: Summary of Key Model Revisions Relevant to the Interagency SCC

IAM	Version used in 2010 Interagency Analysis	New Version	Key changes relevant to interagency SCC
DICE	2007	2010	Updated calibration of the carbon cycle model and explicit representation of sea level rise (SLR) and associated damages.
FUND	3.5 (2009)	3.8 (2012)	Updated damage functions for space heating, SLR, agricultural impacts, changes to transient response of temperature to buildup of GHG concentrations, and inclusion of indirect climate effects of methane.
PAGE	2002	2009	Explicit representation of SLR damages, revisions to damage function to ensure damages do not exceed 100% of GDP, change in regional scaling of damages, revised treatment of potential abrupt damages, and updated adaptation assumptions.

A. DICE

DICE 2010 includes a number of changes over the previous 2007 version used in the 2010 interagency report. The model changes that are relevant for the SCC estimates developed by the interagency working group include: 1) updated parameter values for the carbon cycle model, 2) an explicit representation of sea level dynamics, and 3) a re-calibrated damage function that includes an explicit representation of economic damages from sea level rise. Changes were also made to other parts of the DICE model—including the equilibrium climate sensitivity parameter, the rate of change of total factor productivity, and the elasticity of the marginal utility of consumption—but these components of DICE are superseded by the interagency working group’s assumptions and so will not be discussed here. More details on DICE2007 can be found in Nordhaus (2008) and on DICE2010 in Nordhaus (2010). The DICE2010 model and documentation is also available for download from the homepage of William Nordhaus.

Carbon Cycle Parameters

DICE uses a three-box model of carbon stocks and flows to represent the accumulation and transfer of carbon among the atmosphere, the shallow ocean and terrestrial biosphere, and the deep ocean. These parameters are “calibrated to match the carbon cycle in the Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC)” (Nordhaus 2008 p 44).⁴ Carbon cycle transfer coefficient values

⁴ MAGICC is a simple climate model initially developed by the U.S. National Center for Atmospheric Research that has been used heavily by the Intergovernmental Panel on Climate Change (IPCC) to emulate projections from more sophisticated state of the art earth system simulation models (Randall et al. 2007).

in DICE2010 are based on re-calibration of the model to match the newer 2009 version of MAGICC (Nordhaus 2010 p 2). For example, in DICE2010, in each decade, 12 percent of the carbon in the atmosphere is transferred to the shallow ocean, 4.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 94.8 percent remains in the shallow ocean, and 0.5 percent is transferred to the deep ocean. For comparison, in DICE 2007, 18.9 percent of the carbon in the atmosphere is transferred to the shallow ocean each decade, 9.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 85.3 percent remains in the shallow ocean, and 5 percent is transferred to the deep ocean.

The implication of these changes for DICE2010 is in general a weakening of the ocean as a carbon sink and therefore a higher concentration of carbon in the atmosphere than in DICE2007, for a given path of emissions. All else equal, these changes will generally increase the level of warming and therefore the SCC estimates in DICE2010 relative to those from DICE2007.

Sea Level Dynamics

A new feature of DICE2010 is an explicit representation of the dynamics of the global average sea level anomaly to be used in the updated damage function (discussed below). This section contains a brief description of the sea level rise (SLR) module; a more detailed description can be found on the model developer's website.⁵ The average global sea level anomaly is modeled as the sum of four terms that represent contributions from: 1) thermal expansion of the oceans, 2) melting of glaciers and small ice caps, 3) melting of the Greenland ice sheet, and 4) melting of the Antarctic ice sheet.

The parameters of the four components of the SLR module are calibrated to match consensus results from the IPCC's Fourth Assessment Report (AR4).⁶ The rise in sea level from thermal expansion in each time period (decade) is 2 percent of the difference between the sea level in the previous period and the long run equilibrium sea level, which is 0.5 meters per degree Celsius (°C) above the average global temperature in 1900. The rise in sea level from the melting of glaciers and small ice caps occurs at a rate of 0.008 meters per decade per °C above the average global temperature in 1900.

The contribution to sea level rise from melting of the Greenland ice sheet is more complex. The equilibrium contribution to SLR is 0 meters for temperature anomalies less than 1 °C and increases linearly from 0 meters to a maximum of 7.3 meters for temperature anomalies between 1 °C and 3.5 °C. The contribution to SLR in each period is proportional to the difference between the previous period's sea level anomaly and the equilibrium sea level anomaly, where the constant of proportionality increases with the temperature anomaly in the current period.

⁵ Documentation on the new sea level rise module of DICE is available on William Nordhaus' website at: http://nordhaus.econ.yale.edu/documents/SLR_021910.pdf.

⁶ For a review of post-IPCC AR4 research on sea level rise, see Nicholls et al. (2011) and NAS (2011).

The contribution to SLR from the melting of the Antarctic ice sheet is -0.001 meters per decade when the temperature anomaly is below 3 °C and increases linearly between 3 °C and 6 °C to a maximum rate of 0.025 meters per decade at a temperature anomaly of 6 °C.

Re-calibrated Damage Function

Economic damages from climate change in the DICE model are represented by a fractional loss of gross economic output in each period. A portion of the remaining economic output in each period (net of climate change damages) is consumed and the remainder is invested in the physical capital stock to support future economic production, so each period's climate damages will reduce consumption in that period and in all future periods due to the lost investment. The fraction of output in each period that is lost due to climate change impacts is represented as one minus a fraction, which is one divided by a quadratic function of the temperature anomaly, producing a sigmoid ("S"-shaped) function.⁷ The loss function in DICE2010 has been expanded by adding a quadratic function of SLR to the quadratic function of temperature. In DICE2010 the temperature anomaly coefficients have been recalibrated to avoid double-counting damages from sea level rise that were implicitly included in these parameters in DICE2007.

The aggregate damages in DICE2010 are illustrated by Nordhaus (2010 p 3), who notes that "...damages in the uncontrolled (baseline) [i.e., reference] case ... in 2095 are \$12 trillion, or 2.8 percent of global output, for a global temperature increase of 3.4 °C above 1900 levels." This compares to a loss of 3.2 percent of global output at 3.4 °C in DICE2007. However, in DICE2010, annual damages are lower in most of the early periods of the modeling horizon but higher in later periods than would be calculated using the DICE2007 damage function. Specifically, the percent difference between damages in the base run of DICE2010 and those that would be calculated using the DICE2007 damage function starts at +7 percent in 2005, decreases to a low of -14 percent in 2065, then continuously increases to +20 percent by 2300 (the end of the interagency analysis time horizon), and to +160 percent by the end of the model time horizon in 2595. The large increases in the far future years of the time horizon are due to the permanence associated with damages from sea level rise, along with the assumption that the sea level is projected to continue to rise long after the global average temperature begins to decrease. The changes to the loss function generally decrease the interagency working group SCC estimates slightly given that relative increases in damages in later periods are discounted more heavily, all else equal.

B. FUND

FUND version 3.8 includes a number of changes over the previous version 3.5 (Narita et al. 2010) used in the 2010 interagency report. Documentation supporting FUND and the model's source code for all versions of the model is available from the model authors.⁸ Notable changes, due to their impact on the

⁷ The model and documentation, including formulas, are available on the author's webpage at <http://www.econ.yale.edu/~nordhaus/homepage/RICEmodels.htm>.

⁸ <http://www.fund-model.org/>. This report uses version 3.8 of the FUND model, which represents a modest update to the most recent version of the model to appear in the literature (version 3.7) (Anthoff and Tol, 2013). For the purpose of computing the SCC, the relevant changes (between 3.7 to 3.8) are associated with improving

SCC estimates, are adjustments to the space heating, agriculture, and sea level rise damage functions in addition to changes to the temperature response function and the inclusion of indirect effects from methane emissions.⁹ We discuss each of these in turn.

Space Heating

In FUND, the damages associated with the change in energy needs for space heating are based on the estimated impact due to one degree of warming. These baseline damages are scaled based on the forecasted temperature anomaly's deviation from the one degree benchmark and adjusted for changes in vulnerability due to economic and energy efficiency growth. In FUND 3.5, the function that scales the base year damages adjusted for vulnerability allows for the possibility that in some simulations the benefits associated with reduced heating needs may be an unbounded convex function of the temperature anomaly. In FUND 3.8, the form of the scaling has been modified to ensure that the function is everywhere concave and that there will exist an upper bound on the benefits a region may receive from reduced space heating needs. The new formulation approaches a value of two in the limit of large temperature anomalies, or in other words, assuming no decrease in vulnerability, the reduced expenditures on space heating at any level of warming will not exceed two times the reductions experienced at one degree of warming. Since the reduced need for space heating represents a benefit of climate change in the model, or a negative damage, this change will increase the estimated SCC. This update accounts for a significant portion of the difference in the expected SCC estimates reported by the two versions of the model when run probabilistically.

Sea Level Rise and Land Loss

The FUND model explicitly includes damages associated with the inundation of dry land due to sea level rise. The amount of land lost within a region is dependent upon the proportion of the coastline being protected by adequate sea walls and the amount of sea level rise. In FUND 3.5 the function defining the potential land lost in a given year due to sea level rise is linear in the rate of sea level rise for that year. This assumption implicitly assumes that all regions are well represented by a homogeneous coastline in length and a constant uniform slope moving inland. In FUND 3.8 the function defining the potential land lost has been changed to be a convex function of sea level rise, thereby assuming that the slope of the shore line increases moving inland. The effect of this change is to typically reduce the vulnerability of some regions to sea level rise based land loss, thereby lowering the expected SCC estimate.¹⁰

consistency with IPCC AR4 by adjusting the atmospheric lifetimes of CH₄ and N₂O and incorporating the indirect forcing effects of CH₄, along with making minor stability improvements in the sea wall construction algorithm.

⁹ The other damage sectors (water resources, space cooling, land loss, migration, ecosystems, human health, and extreme weather) were not significantly updated.

¹⁰ For stability purposes this report also uses an update to the model which assumes that regional coastal protection measures will be built to protect the most valuable land first, such that the marginal benefits of coastal protection is decreasing in the level of protection following Fankhauser (1995).

Agriculture

In FUND, the damages associated with the agricultural sector are measured as proportional to the sector's value. The fraction is bounded from above by one and is made up of three additive components that represent the effects from carbon fertilization, the rate of temperature change, and the level of the temperature anomaly. In both FUND 3.5 and FUND 3.8, the fraction of the sector's value lost due to the level of the temperature anomaly is modeled as a quadratic function with an intercept of zero. In FUND 3.5, the coefficients of this loss function are modeled as the ratio of two random normal variables. This specification had the potential for unintended extreme behavior as draws from the parameter in the denominator approached zero or went negative. In FUND 3.8, the coefficients are drawn directly from truncated normal distributions so that they remain in the range $[0, \infty)$ and $(-\infty, 0]$, respectively, ensuring the correct sign and eliminating the potential for divide by zero errors. The means for the new distributions are set equal to the ratio of the means from the normal distributions used in the previous version. In general the impact of this change has been to decrease the range of the distribution while spreading out the distributions' mass over the remaining range relative to the previous version. The net effect of this change on the SCC estimates is difficult to predict.

Transient Temperature Response

The temperature response model translates changes in global levels of radiative forcing into the current expected temperature anomaly. In FUND, a given year's increase in the temperature anomaly is based on a mean reverting function where the mean equals the equilibrium temperature anomaly that would eventually be reached if that year's level of radiative forcing were sustained. The rate of mean reversion defines the rate at which the transient temperature approaches the equilibrium. In FUND 3.5, the rate of temperature response is defined as a decreasing linear function of equilibrium climate sensitivity to capture the fact that the progressive heat uptake of the deep ocean causes the rate to slow at higher values of the equilibrium climate sensitivity. In FUND 3.8, the rate of temperature response has been updated to a quadratic function of the equilibrium climate sensitivity. This change reduces the sensitivity of the rate of temperature response to the level of the equilibrium climate sensitivity, a relationship first noted by Hansen et al. (1985) based on the heat uptake of the deep ocean. Therefore in FUND 3.8, the temperature response will typically be faster than in the previous version. The overall effect of this change is likely to increase estimates of the SCC as higher temperatures are reached during the timeframe analyzed and as the same damages experienced in the previous version of the model are now experienced earlier and therefore discounted less.

Methane

The IPCC AR4 notes a series of indirect effects of methane emissions, and has developed methods for proxying such effects when computing the global warming potential of methane (Forster et al. 2007). FUND 3.8 now includes the same methods for incorporating the indirect effects of methane emissions. Specifically, the average atmospheric lifetime of methane has been set to 12 years to account for the feedback of methane emissions on its own lifetime. The radiative forcing associated with atmospheric methane has also been increased by 40% to account for its net impact on ozone production and

stratospheric water vapor. All else equal, the effect of this increased radiative forcing will be to increase the estimated SCC values, due to greater projected temperature anomaly.

C. PAGE

PAGE09 (Hope 2013) includes a number of changes from PAGE2002, the version used in the 2010 SCC interagency report. The changes that most directly affect the SCC estimates include: explicitly modeling the impacts from sea level rise, revisions to the damage function to ensure damages are constrained by GDP, a change in the regional scaling of damages, a revised treatment for the probability of a discontinuity within the damage function, and revised assumptions on adaptation. The model also includes revisions to the carbon cycle feedback and the calculation of regional temperatures.¹¹ More details on PAGE09 can be found in Hope (2011a, 2011b, 2011c). A description of PAGE2002 can be found in Hope (2006).

Sea Level Rise

While PAGE2002 aggregates all damages into two categories – economic and non-economic impacts –, PAGE09 adds a third explicit category: damages from sea level rise. In the previous version of the model, damages from sea level rise were subsumed by the other damage categories. In PAGE09 sea level damages increase less than linearly with sea level under the assumption that land, people, and GDP are more concentrated in low-lying shoreline areas. Damages from the economic and non-economic sector were adjusted to account for the introduction of this new category.

Revised Damage Function to Account for Saturation

In PAGE09, small initial economic and non-economic benefits (negative damages) are modeled for small temperature increases, but all regions eventually experience economic damages from climate change, where damages are the sum of additively separable polynomial functions of temperature and sea level rise. Damages transition from this polynomial function to a logistic path once they exceed a certain proportion of remaining Gross Domestic Product (GDP) to ensure that damages do not exceed 100 percent of GDP. This differs from PAGE2002, which allowed Eastern Europe to potentially experience large benefits from temperature increases, and which also did not bound the possible damages that could be experienced.

Regional Scaling Factors

As in the previous version of PAGE, the PAGE09 model calculates the damages for the European Union (EU) and then, assumes that damages for other regions are proportional based on a given scaling factor. The scaling factor in PAGE09 is based on the length of a region's coastline relative to the EU (Hope 2011b). Because of the long coastline in the EU, other regions are, on average, less vulnerable than the EU for the same sea level and temperature increase, but all regions have a positive scaling factor. PAGE2002 based its scaling factors on four studies reported in the IPCC's third assessment report, and allowed for benefits

¹¹ Because several changes in the PAGE model are structural (e.g., the addition of sea level rise and treatment of discontinuity), it is not possible to assess the direct impact of each change on the SCC in isolation as done for the other two models above.

from temperature increase in Eastern Europe, smaller impacts in developed countries, and higher damages in developing countries.

Probability of a Discontinuity

In PAGE2002, the damages associated with a “discontinuity” (nonlinear extreme event) were modeled as an expected value. Specifically, a stochastic probability of a discontinuity was multiplied by the damages associated with a discontinuity to obtain an expected value, and this was added to the economic and non-economic impacts. That is, additional damages from an extreme event, such as extreme melting of the Greenland ice sheet, were multiplied by the probability of the event occurring and added to the damage estimate. In PAGE09, the probability of discontinuity is treated as a discrete event for each year in the model. The damages for each model run are estimated either with or without a discontinuity occurring, rather than as an expected value. A large-scale discontinuity becomes possible when the temperature rises beyond some threshold value between 2 and 4°C. The probability that a discontinuity will occur beyond this threshold then increases by between 10 and 30 percent for every 1°C rise in temperature beyond the threshold. If a discontinuity occurs, the EU loses an additional 5 to 25 percent of its GDP (drawn from a triangular distribution with a mean of 15 percent) in addition to other damages, and other regions lose an amount determined by the regional scaling factor. The threshold value for a possible discontinuity is lower than in PAGE2002, while the rate at which the probability of a discontinuity increases with the temperature anomaly and the damages that result from a discontinuity are both higher than in PAGE2002. The model assumes that only one discontinuity can occur and that the impact is phased in over a period of time, but once it occurs, its effect is permanent.

Adaptation

As in PAGE2002, adaptation is available to help mitigate any climate change impacts that occur. In PAGE this adaptation is the same regardless of the temperature change or sea level rise and is therefore akin to what is more commonly considered a reduction in vulnerability. It is modeled by reducing the damages by some percentage. PAGE09 assumes a smaller decrease in vulnerability than the previous version of the model and assumes that it will take longer for this change in vulnerability to be realized. In the aggregated economic sector, at the time of full implementation, this adaptation will mitigate all damages up to a temperature increase of 1°C, and for temperature anomalies between 1°C and 2°C, it will reduce damages by 15-30 percent (depending on the region). However, it takes 20 years to fully implement this adaptation. In PAGE2002, adaptation was assumed to reduce economic sector damages up to 2°C by 50-90 percent after 20 years. Beyond 2°C, no adaptation is assumed to be available to mitigate the impacts of climate change. For the non-economic sector, in PAGE09 adaptation is available to reduce 15 percent of the damages due to a temperature increase between 0°C and 2°C and is assumed to take 40 years to fully implement, instead of 25 percent of the damages over 20 years assumed in PAGE2002. Similarly, adaptation is assumed to alleviate 25-50 percent of the damages from the first 0.20 to 0.25 meters of sea level rise but is assumed to be ineffective thereafter. Hope (2011c) estimates that the less optimistic assumptions regarding the ability to offset impacts of temperature and sea level rise via adaptation increase the SCC by approximately 30 percent.

Other Noteworthy Changes

Two other changes in the model are worth noting. There is a change in the way the model accounts for decreased CO₂ absorption on land and in the ocean as temperature rises. PAGE09 introduces a linear feedback from global mean temperature to the percentage gain in the excess concentration of CO₂, capped at a maximum level. In PAGE2002, an additional amount was added to the CO₂ emissions each period to account for a decrease in ocean absorption and a loss of soil carbon. Also updated is the method by which the average global and annual temperature anomaly is downscaled to determine annual average regional temperature anomalies to be used in the regional damage functions. In PAGE2002, the scaling was determined solely based on regional difference in emissions of sulfate aerosols. In PAGE09, this regional temperature anomaly is further adjusted using an additive factor that is based on the average absolute latitude of a region relative to the area weighted average absolute latitude of the Earth's landmass, to capture relatively greater changes in temperature forecast to be experienced at higher latitudes.

III. Revised SCC Estimates

The updated versions of the three integrated assessment models were run using the same methodology detailed in the 2010 TSD (Interagency Working Group on Social Cost of Carbon 2010). The approach along with the inputs for the socioeconomic emissions scenarios, equilibrium climate sensitivity distribution, and discount rate remains the same. This includes the five reference scenarios based on the EMF-22 modeling exercise, the Roe and Baker equilibrium climate sensitivity distribution calibrated to the IPCC AR4, and three constant discount rates of 2.5, 3, and 5 percent.

As was previously the case, the use of three models, three discount rates, and five scenarios produces 45 separate distributions for the global SCC. The approach laid out in the 2010 TSD applied equal weight to each model and socioeconomic scenario in order to reduce the dimensionality down to three separate distributions representative of the three discount rates. The interagency group selected four values from these distributions for use in regulatory analysis. Three values are based on the average SCC across models and socio-economic-emissions scenarios at the 2.5, 3, and 5 percent discount rates, respectively. The fourth value was chosen to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, the 95th percentile of the SCC estimates at a 3 percent discount rate was chosen. (A detailed set of percentiles by model and scenario combination and additional summary statistics for the 2020 values is available in the Appendix.) As noted in the 2010 TSD, "the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate" (Interagency Working Group on Social Cost of Carbon 2010, p. 25). However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance and value of including all four SCC values.

Table 2 shows the four selected SCC estimates in five year increments from 2010 to 2050. Values for 2010, 2020, 2030, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated

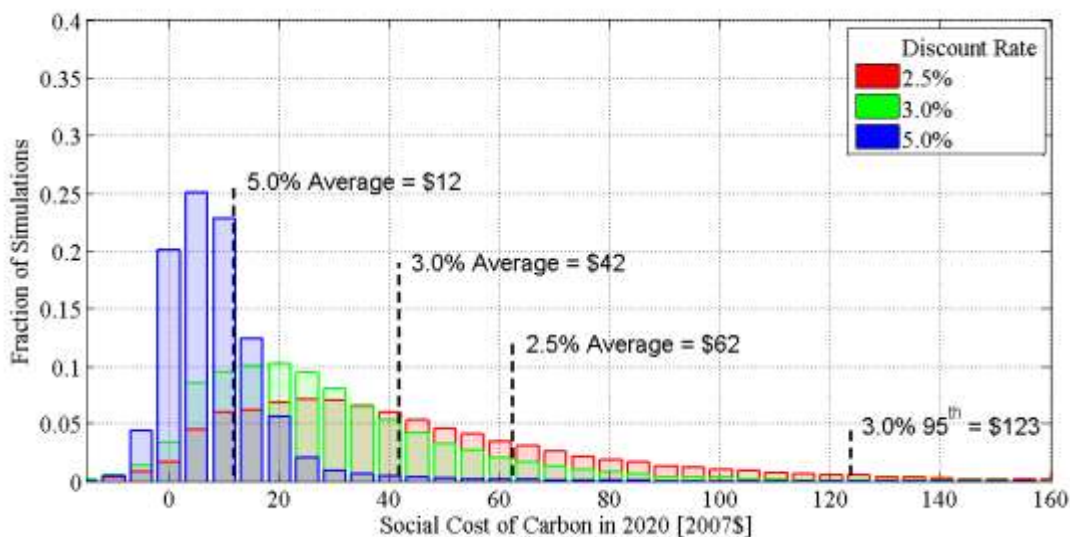
using linear interpolation. The full set of revised annual SCC estimates between 2010 and 2050 is reported in the Appendix.

Table 2: Revised Social Cost of CO₂, 2010 – 2050 (in 2007 dollars per metric ton of CO₂)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD due to the changes to the models outlined in the previous section. By way of comparison, the 2020 SCC estimates reported in the original TSD were \$7, \$26, \$42 and \$81 (2007\$) (Interagency Working Group on Social Cost of Carbon 2010). Figure 1 illustrates where the four SCC values for 2020 fall within the full distribution for each discount rate based on the combined set of runs for each model and scenario (150,000 estimates in total for each discount rate). In general, the distributions are skewed to the right and have long tails. The Figure also shows that the lower the discount rate, the longer the right tail of the distribution.

Figure 1: Distribution of SCC Estimates for 2020 (in 2007\$ per metric ton CO₂)



As was the case in the 2010 TSD, the SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in

response to greater climatic change. The approach taken by the interagency group is to compute the cost of a marginal ton emitted in the future by running the models for a set of perturbation years out to 2050. Table 3 illustrates how the growth rate for these four SCC estimates varies over time.

Table 3: Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Growth Rate (%)	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010-2020	1.2%	3.2%	2.4%	4.4%
2020-2030	3.4%	2.1%	1.7%	2.3%
2030-2040	3.0%	1.9%	1.5%	2.0%
2040-2050	2.6%	1.6%	1.3%	1.6%

The future monetized value of emission reductions in each year (the SCC in year t multiplied by the change in emissions in year t) must be discounted to the present to determine its total net present value for use in regulatory analysis. As previously discussed in the 2010 TSD, damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency – i.e., future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate.

Under current OMB guidance contained in Circular A-4, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. For additional discussion, see the 2010 TSD.

IV. Other Model Limitations and Research Gaps

The 2010 interagency SCC TSD discusses a number of important limitations for which additional research is needed. In particular, the document highlights the need to improve the quantification of both non-catastrophic and catastrophic damages, the treatment of adaptation and technological change, and the way in which inter-regional and inter-sectoral linkages are modeled. While the new version of the models discussed above offer some improvements in these areas, further work remains warranted. The 2010 TSD also discusses the need to more carefully assess the implications of risk aversion for SCC estimation as

well as the inability to perfectly substitute between climate and non-climate goods at higher temperature increases, both of which have implications for the discount rate used. EPA, DOE, and other agencies continue to engage in research on modeling and valuation of climate impacts that can potentially improve SCC estimation in the future.

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Appendix A

Table A1: Annual SCC Values: 2010-2050 (2007\$/metric ton CO₂)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2011	11	32	51	90
2012	11	33	53	93
2013	11	34	54	97
2014	11	35	55	101
2015	11	36	56	105
2016	11	38	57	108
2017	11	39	59	112
2018	12	40	60	116
2019	12	41	61	120
2020	12	42	62	123
2021	12	42	63	126
2022	13	43	64	129
2023	13	44	65	132
2024	13	45	66	135
2025	14	46	68	138
2026	14	47	69	141
2027	15	48	70	143
2028	15	49	71	146
2029	15	49	72	149
2030	16	50	73	152
2031	16	51	74	155
2032	17	52	75	158
2033	17	53	76	161
2034	18	54	77	164
2035	18	55	78	168
2036	19	56	79	171
2037	19	57	81	174
2038	20	58	82	177
2039	20	59	83	180
2040	21	60	84	183
2041	21	61	85	186
2042	22	61	86	189
2043	22	62	87	192
2044	23	63	88	194
2045	23	64	89	197
2046	24	65	90	200
2047	24	66	92	203
2048	25	67	93	206
2049	25	68	94	209
2050	26	69	95	212

Table A2: 2020 Global SCC Estimates at 2.5 Percent Discount Rate (2007\$/metric ton CO₂)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95 th	99th
Scenario ¹²	PAGE									
IMAGE	6	10	15	26	55	123	133	313	493	949
MERGE Optimistic	4	6	8	15	32	75	79	188	304	621
MESSAGE	4	7	10	19	41	104	103	266	463	879
MiniCAM Base	5	8	12	21	45	102	108	255	412	835
5th Scenario	2	4	6	11	24	81	66	192	371	915

Scenario	DICE									
IMAGE	25	31	37	47	64	72	92	123	139	161
MERGE Optimistic	14	18	20	26	36	40	50	65	74	85
MESSAGE	20	24	28	37	51	58	71	95	109	221
MiniCAM Base	20	25	29	38	53	61	76	102	117	135
5th Scenario	17	22	25	33	45	52	65	91	106	126

Scenario	FUND									
IMAGE	-14	-2	4	15	31	39	55	86	107	157
MERGE Optimistic	-6	1	6	14	27	35	46	70	87	141
MESSAGE	-16	-5	1	11	24	31	43	67	83	126
MiniCAM Base	-7	2	7	16	32	39	55	83	103	158
5th Scenario	-29	-13	-6	4	16	21	32	53	69	103

Table A3: 2020 Global SCC Estimates at 3 Percent Discount Rate (2007\$/metric ton CO₂)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	4	7	9	17	36	87	91	228	369	696
MERGE Optimistic	2	4	6	10	22	54	55	136	222	461
MESSAGE	3	5	7	13	28	72	71	188	316	614
MiniCAM Base	3	5	7	13	29	70	72	177	288	597
5th Scenario	1	3	4	7	16	55	46	130	252	632

Scenario	DICE									
IMAGE	16	21	24	32	43	48	60	79	90	102
MERGE Optimistic	10	13	15	19	25	28	35	44	50	58
MESSAGE	14	18	20	26	35	40	49	64	73	83
MiniCAM Base	13	17	20	26	35	39	49	65	73	85
5th Scenario	12	15	17	22	30	34	43	58	67	79

Scenario	FUND									
IMAGE	-13	-4	0	8	18	23	33	51	65	99
MERGE Optimistic	-7	-1	2	8	17	21	29	45	57	95
MESSAGE	-14	-6	-2	5	14	18	26	41	52	82
MiniCAM Base	-7	-1	3	9	19	23	33	50	63	101
5th Scenario	-22	-11	-6	1	8	11	18	31	40	62

¹² See 2010 TSD for a description of these scenarios.

Table A4: 2020 Global SCC Estimates at 5 Percent Discount Rate (2007\$/metric ton CO₂)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	1	2	2	4	10	27	26	68	118	234
MERGE Optimistic	1	1	2	3	6	17	17	43	72	146
MESSAGE	1	1	2	4	8	23	22	58	102	207
MiniCAM Base	1	1	2	3	8	20	20	52	90	182
5th Scenario	0	1	1	2	5	17	14	39	75	199

Scenario	DICE									
IMAGE	6	8	9	11	14	15	18	22	25	27
MERGE Optimistic	4	5	6	7	9	10	12	15	16	18
MESSAGE	6	7	8	10	12	13	16	20	22	25
MiniCAM Base	5	6	7	8	11	12	14	18	20	22
5th Scenario	5	6	6	8	10	11	14	17	19	21

Scenario	FUND									
IMAGE	-9	-5	-4	-1	2	3	6	10	14	24
MERGE Optimistic	-6	-4	-2	0	3	4	6	11	15	26
MESSAGE	-10	-6	-4	-1	1	2	5	9	12	21
MiniCAM Base	-7	-4	-2	0	3	4	6	11	14	25
5th Scenario	-11	-7	-5	-3	0	0	3	5	7	13

Table A5: Additional Summary Statistics of 2020 Global SCC Estimates

Discount rate:	5.0%				3.0%				2.5%			
Statistic:	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	21	1481	5	32	68	13712	4	22	97	26878	4	23
FUND	3	41	5	179	19	1452	-42	8727	33	6154	-73	14931

Appendix B

The November 2013 revision of this technical support document is based on two corrections to the runs based on the FUND model. First, the potential dry land loss in the algorithm that estimates regional coastal protections was misspecified in the model's computer code. This correction is covered in an erratum to Anthoff and Tol (2013) published in the same journal (*Climatic Change*) in October 2013 (Anthoff and Tol (2013b)). Second, the equilibrium climate sensitivity distribution was inadvertently specified as a truncated Gamma distribution (the default in FUND) as opposed to the truncated Roe and Baker distribution as was intended. The truncated Gamma distribution used in the FUND runs had approximately the same mean and upper truncation point, but lower variance and faster decay of the upper tail, as compared to the intended specification based on the Roe and Baker distribution. The difference between the original estimates reported in the May 2013 version of this technical support document and this revision are generally one dollar or less.

The July 2015 revision of this technical support document is based on two corrections. First, the DICE model had been run up to 2300 rather than through 2300, as was intended, thereby leaving out the marginal damages in the last year of the time horizon. Second, due to an indexing error, the results from the PAGE model were in 2008 U.S. dollars rather than 2007 U.S. dollars, as was intended. In the current revision, all models have been run through 2300, and all estimates are in 2007 U.S. dollars. On average the revised SCC estimates are one dollar less than the mean SCC estimates reported in the November 2013 version of this technical support document. The difference between the 95th percentile estimates with a 3% discount rate is slightly larger, as those estimates are heavily influenced by results from the PAGE model.

Exhibit 9



Estimating the Benefits from Carbon Dioxide Emissions Reductions

JULY 2, 2015 AT 2:00 PM ET BY HOWARD SHELANSKI AND MAURICE OBSTFELD



Summary: The social cost of carbon (SCC) is a tool that helps Federal agencies decide which carbon-reducing regulatory approaches make the most sense

By now, just about everyone accepts that carbon dioxide emissions from burning fossil fuels are warming our planet and changing our climate in harmful ways. With growing frequency we see headlines about extreme weather events such as heat waves, polar melting, severe drought, and violent storms—a dangerous mix whose costs for our economy and environment will only grow over time. Transitioning to a lower carbon economy is an essential step toward reducing these costs. The social cost of carbon (SCC) is a tool that helps Federal agencies decide which carbon-reducing regulatory approaches make the most sense—to know which come at too great a cost and which are a good deal for society. The SCC is a range of estimates, in dollars, of the long-term damage done by one ton of carbon emissions.

The effort to incorporate the SCC into regulatory impact analysis started during the Bush Administration. At that time, each Federal agency developed its own estimate of the SCC using a variety of methodologies. In 2009, the Obama Administration established a working group of technical experts from across the government to develop a single set of estimates, based on the best available science and economics, to be used by all agencies in their emissions reducing regulations. In February 2010, after considering public

comments on interim values that agencies had been using, the working group released harmonized and improved SCC estimates, along with a [Technical Support Document \(TSD\)](#) that explained how the SCC estimates were derived. Recognizing that the underlying models would evolve and improve over time as scientific and economic understanding increased, the Administration committed to periodic updates of the 2010 estimates.

In November 2013, OMB published a [request for comment](#) on a set of updated SCC estimates and the methodology used to develop them, to supplement the comments already routinely received when agencies use the SCC in particular rulemakings. In response, we received about 150 substantive comments, some quite lengthy and technical, as well as about 39,000 form letters that expressed support for our efforts to establish a harmonized SCC.

Today, we are following up on that public comment process and announcing next steps for further refining the social cost of carbon:

- First, we are publishing a [detailed summary and formal response](#) to the many thoughtful comments we received.
- Second, we are issuing some minor technical revisions to the SCC, and publishing a [revised TSD](#) that explains those changes. The resulting central SCC estimate for a ton of CO₂ emitted in 2015 is \$36.
- Third, to ensure that the next SCC update keeps up with the latest available science and economics, we will seek independent expert advice on opportunities to improve the estimates, including many of the approaches suggested by commenters and summarized in the Response to Comments document. Specifically, we are asking the National Academies of Sciences, Engineering, and Medicine to provide advice on the pros and cons of potential approaches to future updates. Input from the Academies, informed by on-going public comment and the peer-reviewed literature, will help to ensure that the SCC estimates used by the federal government continue to reflect the best available science and economics. Federal agencies will continue to use the current SCC estimates in regulatory impact analysis until further updates can be made to reflect the forthcoming guidance from the Academies.

The SCC will become increasingly important if we are to protect our economy, environment, and quality of life for current and future generations from the mounting costs of climate change. The Administration is committed to ensuring consistency across Federal agencies in how they value the carbon emission reductions that will result from their rules. We will continue to keep these estimates informed by the most up-to-date science and economics so that agencies can appropriately account for the social cost of carbon emissions in evaluating the costs and benefits of their regulations.

Howard Shelanski is the Administrator of the Office of Information and Regulatory Affairs. Maurice Obstfeld is a Member of the Council of Economic Advisers.



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Exhibit 10



July 2014

REGULATORY IMPACT ANALYSIS

Development of Social Cost of Carbon Estimates

Why GAO Did This Study

Executive Order 12866 directs federal agencies to assess the economic effects of their proposed significant regulatory actions, including a determination that a regulation's benefits justify the costs. In 2008, a federal appeals court directed DOT to update a regulatory impact analysis with an estimate of the social cost of carbon—the dollar value of the net effects (damages and benefits) of an increase in emissions of carbon dioxide, a greenhouse gas.

In 2009, the Interagency Working Group on Social Cost of Carbon was convened to develop estimates for use governmentwide, and it issued final estimates in its 2010 Technical Support Document. In 2013, the group issued revised estimates that were about 50 percent higher than the 2010 estimates, which raised public interest.

GAO was asked to review the working group's development of social cost of carbon estimates. This report describes the participating entities and processes and methods they used to develop the 2010 and 2013 estimates. GAO reviewed executive orders, OMB guidance, the Technical Support Document, its 2013 update, and other key documents. GAO interviewed officials who participated in the working group on behalf of the EOP offices and agencies involved. GAO did not evaluate the quality of the working group's approach.

GAO is making no recommendations in this report. Of seven agencies, OMB and Treasury provided written or oral comments and generally agreed with the findings in this report. Other agencies provided technical comments only or had no comments.

View [GAO-14-663](#). For more information, contact J. Alfredo Gómez at (202) 512-3841 or gomezj@gao.gov.

July 2014

REGULATORY IMPACT ANALYSIS

Development of Social Cost of Carbon Estimates

What GAO Found

To develop the 2010 and 2013 social cost of carbon estimates, the Office of Management and Budget (OMB) and Council of Economic Advisers convened and led an informal interagency working group in which four other offices from the Executive Office of the President (EOP) and six federal agencies participated. Participating agencies were the Environmental Protection Agency (EPA) and the Departments of Agriculture, Commerce, Energy, Transportation (DOT), and the Treasury. According to several working group participants, the working group included relevant subject-matter experts and the agencies likely to use the estimates in future rulemakings. According to OMB staff, there is no single approach for convening informal interagency working groups and no requirement that this type of working group should document its activities or proceedings. However, OMB and EPA participants stated that the working group documented all major issues discussed in the Technical Support Document, which is consistent with federal standards for internal control. According to the Technical Support Document and participants GAO interviewed, the working group's processes and methods reflected the following three principles:

- **Used consensus-based decision making.** The working group used a consensus-based approach for making key decisions in developing the 2010 and 2013 estimates. Participants generally stated that they were satisfied that the Technical Support Document addressed individual comments on draft versions and reflected the overall consensus of the working group.
- **Relied on existing academic literature and models.** The working group relied largely on existing academic literature and models to develop its estimates. Specifically, the working group used three prevalent academic models that integrate climate and economic data to estimate future economic effects from climate change. The group agreed on three modeling inputs reflecting the wide uncertainty in the academic literature, including discount rates. Once the group reached agreement, EPA officials—sometimes with the assistance of the model developers—calculated the estimates. All other model assumptions and features were unchanged by the working group, which weighted each model equally to calculate estimates. After the academic models were updated to reflect new scientific information, such as in sea level rise and associated damages, the working group used the updated models to revise its estimates in 2013, resulting in higher estimates.
- **Took steps to disclose limitations and incorporate new information.** The Technical Support Document discloses several limitations of the estimates and areas that the working group identified as being in need of additional research. It also sets a goal of revisiting the estimates when substantially updated models become available. Since 2008, agencies have published dozens of regulatory actions for public comment that use various social cost of carbon estimates in regulatory analyses and, according to working group participants, agencies received many comments on the estimates throughout this process. Several participants told GAO that the working group decided to revise the estimates in 2013 after a number of public comments encouraged revisions because the models used to develop the 2010 estimates had been updated and used in peer-reviewed academic literature.

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Abbreviations

ADS-B	Automatic Dependent Surveillance-Broadcast
ATC	Air Traffic Control
DICE	Dynamic Integrated Climate and Economy
DOT	Department of Transportation
EOP	Executive Office of the President
EPA	Environmental Protection Agency
FUND	Climate Framework for Uncertainty, Negotiation, and Distribution
NHTSA	National Highway Traffic Safety Administration
OMB	Office of Management and Budget
PAGE	Policy Analysis of the Greenhouse Effect

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July 24, 2014

The Honorable David Vitter
Ranking Member
Committee on Environment and Public Works
United States Senate

The Honorable Tim Murphy
Chairman
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
House of Representatives

The Honorable John Culberson
House of Representatives

The Honorable Duncan Hunter
House of Representatives

To encourage a regulatory system that protects and improves health, safety, the environment, and the economy, without imposing unreasonable costs on society, federal agencies are required to assess the economic effects of proposed significant regulatory actions. Agencies can use regulatory impact analysis to assess whether a proposed regulation's benefits justify the costs. For example, regulations aimed at benefiting society by decreasing health risks associated with air pollution may require regulated entities, such as power plants, to incur costs for installing pollution control technologies. According to Environmental Protection Agency (EPA) officials, beginning in 2008, some agencies' regulatory impact analyses incorporated estimates of the social cost of carbon,¹ which agencies use to value the net effects of reducing or

¹The social cost of carbon (measured in dollars per metric ton of carbon dioxide) is the monetized net effects (damages and benefits) associated with an incremental increase in carbon emissions in a given year. Estimates of the social cost of carbon depend on the data and the models used to calculate them and can include a wide range of damage categories, such as projected changes in net agricultural productivity, human health, and property damages from increased flood risk due to increased carbon emissions. Monetization is the process of estimating the dollar value of benefits and costs.

increasing carbon dioxide emissions.² In 2009, in part because agencies used varying estimates of the social cost of carbon, the Executive Office of the President's (EOP) Office of Management and Budget (OMB) and Council of Economic Advisers convened an interagency working group to develop social cost of carbon estimates for federal agencies to use in their regulatory impact analyses. The working group finalized its estimates in 2010 and included them in a document—called the Technical Support Document—that also provides guidance for agencies on using the estimates.³ In May 2013, the working group issued an update to the Technical Support Document that included revised estimates of the social cost of carbon.⁴ These 2013 estimates of the social cost of carbon were approximately 50 percent higher than the 2010 estimates, which raised public interest.

You asked us to review the interagency working group's development of social cost of carbon estimates. This report describes the approach used, including participating entities and processes and methods, to develop the 2010 and 2013 social cost of carbon estimates for regulatory impact analysis.

To address this objective, we reviewed pertinent requirements and guidance, including executive orders and OMB guidance; the Technical Support Document and its 2013 update; published materials and presentations by working group participants on the development of the social cost of carbon estimates; and related GAO reports. We interviewed current and former federal officials or staff who participated in the working group on behalf of the EOP offices and agencies named in the Technical

²Carbon dioxide is a greenhouse gas recognized as a major contributor to climate change. Concentrations of greenhouse gases—including carbon dioxide, methane, nitrous oxide, and synthetic chemicals such as fluorinated gases—trap heat in the atmosphere and prevent it from returning to space.

³Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866* (Washington, D.C.: February 2010).

⁴Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866* (Washington, D.C.: May 2013). This document was reissued with minor technical corrections in November 2013.

Support Document.⁵ We identified these participants by contacting all of the agencies and OMB and then following up with additional individuals identified during our discussions with them. Through this process, we interviewed over 20 individuals who participated in the working group to develop the estimates in the Technical Support Document or its 2013 update, or both. We also corresponded with researchers who developed key academic materials the working group used. Our review describes the approach the working group used to develop estimates of the social cost of carbon; evaluating the quality of the approach is outside the scope of this review.

We conducted this performance audit from November 2013 to July 2014 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

Executive Order 12866 directs federal agencies to assess the potential costs and benefits of their significant regulatory actions, consisting of several categories of regulatory actions, including those likely to result in a rule that may have an annual effect on the economy of \$100 million or more or that have a material adverse effect on the economy; a sector of the economy; productivity; competition; jobs; the environment; public health or safety; or state, local, or tribal governments or communities.⁶ Under the executive order, for regulatory actions expected to meet this

⁵According to the Technical Support Document, the working group consisted of participants from the Council of Economic Advisers, Council on Environmental Quality, EPA, National Economic Council, Office of Energy and Climate Change, OMB, Office of Science and Technology Policy, and the Departments of Agriculture, Commerce, Energy, Transportation, and the Treasury. In March 2011, the Office of Energy and Climate Change joined the Domestic Policy Council.

⁶Exec. Order No. 12866, 58 Fed. Reg. 51,735 (Sept. 30, 1993). Other significant regulatory actions include those that are likely to result in a rule that may create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in Executive Order 12866.

threshold, or economically significant regulatory actions, agencies must also assess costs and benefits of reasonably feasible alternatives and explain why the planned regulatory action is preferable to the identified alternatives. For each significant regulatory action, the agency is to develop the proposed regulation and associated regulatory impact analysis and submit them to OMB for formal review. After OMB concludes its review, the agency is to publish the proposed rule in the *Federal Register* for public comment. The agency is to issue a document summarizing its consideration of the public comments and, if appropriate, modify the proposed rule in response to the comments. This phase of regulatory development may also include further internal and external review. For significant regulatory actions, the agency is to submit the final regulatory impact analysis and regulation to OMB for review before it publishes the final rule.

In 2003, OMB issued Circular A-4 to provide guidance to federal agencies on the development of regulatory analysis as directed by Executive Order 12866.⁷ Circular A-4 states that it is designed to assist agencies by defining good regulatory analysis and standardizing the way benefits and costs of federal regulatory actions are measured and reported. In particular, the guidance provides for systematic evaluation of qualitative and quantitative benefits and costs, including their monetization. Circular A-4 also provides guidance on the selection of discount rates to adjust the estimated benefits and costs for differences in timing.⁸ According to Circular A-4, a regulatory impact analysis should include an evaluation of the benefits and costs of the proposed action and any reasonable alternatives, as well as a description of assumptions and uncertainty.⁹ It acknowledges that agencies cannot analyze all regulations according to a

⁷OMB, Circular A-4: Regulatory Analysis (Sept. 17, 2003).

⁸When the benefits and costs of a regulatory action will occur in the future, agencies must determine the present value of future benefits and costs by applying an appropriate discount rate—the interest rate used to convert benefits and costs occurring in different time periods to a common present value.

⁹Circular A-4 states that agencies should discount future benefits and costs using rates of 3 and 7 percent but notes that agencies may, in addition, consider a lower discount rate if a rule will have important intergenerational benefits or costs. In July 2014, we reported on the application of the guidance in Circular A-4 and the Technical Support Document and made recommendations to OMB to help clarify the relationship between those two documents. See GAO, *Environmental Regulation: EPA Should Improve Adherence to Guidance for Selected Elements of Regulatory Impact Analyses*, [GAO-14-519](#) (Washington, D.C.: July 18, 2014).

formula, and that different regulations may call for different emphases in the analysis. Executive Order 13563, which reaffirmed and supplemented Executive Order 12866 in 2011, generally directs federal agencies to conduct regulatory actions based on the best available science.¹⁰ It also directs agencies to use the best available techniques to quantify benefits and costs accurately.

Federal agencies began including estimates of the social cost of carbon in regulatory impact analyses following a decision by the U.S. Court of Appeals for the Ninth Circuit. Specifically, in 2006, the Department of Transportation's National Highway Traffic Safety Administration (NHTSA) issued a final rule on fuel economy standards for certain vehicles which, like other regulations at the time, did not include estimates of the social cost of carbon.¹¹ The final rule stated that the agency had identified a benefit from a significant reduction in carbon dioxide emissions but stated that the dollar value of the benefit could not be determined because of the wide variation in published estimates of the social cost of carbon. In 2008, in response to a challenge from 11 states and several other organizations, the Ninth Circuit held that NHTSA had acted arbitrarily and capriciously by failing to monetize the value of carbon emissions reduction and directed NHTSA to include such a monetized value in an updated regulatory impact analysis for the regulation.¹² The court stated that, "[w]hile the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."¹³ Following the court's decision, the Department of Energy, the Department of Transportation, and EPA incorporated a variety of individually developed estimates of the social cost of carbon into their regulatory analyses. These estimates were derived from academic literature and ranged, in general, from \$0 to \$159 (in 2006, 2007, or 2008 dollars) per metric ton of carbon dioxide emitted

¹⁰Exec. Order No. 13563, 76 Fed. Reg. 3821 (Jan. 18, 2011).

¹¹Average Fuel Economy Standards for Light Trucks Model Years 2008-2011, 71 Fed. Reg. 17,566 (Apr. 6, 2006). According to EPA officials, other regulations at the time did not typically quantify changes in carbon emissions.

¹²*Ctr. For Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1203 (9th Cir. 2008). The Ninth Circuit issued the 2008 opinion after vacating and withdrawing its prior opinion, 508 F.3d 508, issued on Nov. 15, 2007.

¹³*Id.* at 1200.

in 2007. They also varied in whether they reflected domestic or global measures of the social cost of carbon.¹⁴

In early 2009, in part to improve consistency in agencies' use of social cost of carbon estimates for regulatory impact analysis, OMB's Office of Information and Regulatory Affairs and the Council of Economic Advisers convened the Interagency Working Group on Social Cost of Carbon. The working group developed interim governmentwide social cost of carbon estimates based on an average of selected estimates published in academic literature. The interim estimates first appeared—and, thus, were first available for public review—in August 2009 in the Department of Energy's final rule on energy standards for vending machines.¹⁵ Agencies subsequently incorporated the interim estimates into several published regulatory actions that sought public comments to inform the development of final estimates for future use. The middle or "central" value for the range of interim estimates was \$19 (in 2006 dollars) per metric ton of carbon dioxide emitted in 2007.¹⁶

In October 2009, after developing the interim estimates, the working group reassembled to begin developing the final social cost of carbon estimates issued in the Technical Support Document. While the Technical Support Document is dated February 2010, it was first released publicly in March 2010 as an appendix to the Department of Energy's final rule on energy standards for small electric motors.¹⁷ Subsequently, dozens of published regulatory actions incorporated the estimates. The Technical

¹⁴The benefits and costs of reducing most greenhouse gas emissions, including carbon dioxide, differ from most other benefits and costs in at least two respects: (1) greenhouse gas emissions can contribute to global damages even when emitted in the United States because these emissions can disperse widely throughout the atmosphere, and (2) these emissions generally remain in the atmosphere for years, causing subsequent long-term damages. While Circular A-4 states that agencies should generally estimate domestic benefits and costs of regulations, it also provides latitude to include global economic effects resulting from regulations when relevant and states that such effects should be reported separately and in addition to domestic effects.

¹⁵Energy Conservation Program: Energy Conservation Standards for Refrigerated Bottled or Canned Beverage Vending Machines, 74 Fed. Reg. 44,914 (Aug. 31, 2009).

¹⁶The working group calculated five interim estimates of the social cost of carbon using different discount rate scenarios and referred to \$19—the middle of the five estimates—as the "central value."

¹⁷Energy Conservation Program: Energy Conservation Standards for Small Electric Motors, 75 Fed. Reg. 10,874 (Mar. 9, 2010).

Support Document states that the working group agreed to regularly update the social cost of carbon estimates as the research underlying the estimates evolves. In June 2013, after using the 2010 estimates in an earlier proposal of the rule, the Department of Energy’s final rule on energy standards for microwaves was the first regulatory action to incorporate the revised estimates developed by the working group in the 2013 update to the Technical Support Document.¹⁸ Table 1 shows the central values for the range of 2010 and 2013 social cost of carbon estimates for carbon emissions occurring in selected years.

Table 1: Central Values for the Social Cost of Carbon Estimates Issued by the Interagency Working Group on Social Cost of Carbon in 2010 and 2013

Dollars are 2007 dollars per metric ton of carbon dioxide

Year	2010 central values	2013 central values
2010	\$21	\$32
2020	26	43
2030	33	52
2040	39	61
2050	\$45	\$71

Source: Interagency Working Group on Social Cost of Carbon’s Technical Support Document and 2013 update. | GAO-14-663

Note: The Technical Support Document states that the working group calculated the social cost of carbon for emissions occurring in multiple future years to cover the time horizons anticipated for upcoming regulatory analysis. When the benefits and costs of a regulatory action will occur in the future, agencies must determine the present value of future benefits and costs by applying an appropriate discount rate—the interest rate used to convert benefits and costs occurring in different periods to a common present value. According to the Technical Support Document, the social cost of carbon estimates increase over time because future emissions are expected to produce larger incremental damages as the environment and the economy become more stressed in response to greater climate change. The working group selected four values of the social cost of carbon for regulatory analysis. The first three values are based on the average of estimates calculated at discount rates of 2.5 percent, 3 percent, and 5 percent, and the fourth value was included to represent higher-than-expected economic impacts at the 3 percent discount rate. The Technical Support Document refers to the average of estimates calculated at the 3 percent discount rate as the “central value” of the social cost of carbon and states that agencies should consider all four values when conducting regulatory analyses.

Appendix I lists regulatory actions from 2008 to 2014 and the type of social cost of carbon estimates (i.e., individually developed, interim, 2010, or 2013) incorporated in the actions’ regulatory analyses.

¹⁸Energy Conservation Program: Energy Conservation Standards for Standby Mode and Off Mode for Microwave Ovens, 78 Fed. Reg. 36,316 (June 17, 2013).

Approach Used to Develop Estimates of the Social Cost of Carbon

According to the Technical Support Document and participants we interviewed, the working group consisted of participants representing six EOP offices and six federal agencies and was convened under Executive Order 12866. The working group's processes and methods for developing the estimates reflected three key principles. Specifically, according to participants, the working group (1) used consensus-based decision making; (2) relied largely on existing academic literature and models, including technical assistance from outside resources; and (3) took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available.

Participating Entities

According to the Technical Support Document and participants we spoke with, OMB and the Council of Economic Advisers convened and led the working group, and four other EOP offices and six federal agencies actively participated in the group. According to several participants, the participating EOP offices included the relevant subject-matter experts to best contribute on behalf of the EOP,¹⁹ and the other participating agencies were those likely to conduct rulemakings affecting carbon emissions and, therefore, use the social cost of carbon estimates in the future. For example, EPA and the Department of Energy have issued numerous rules using the social cost of carbon estimates (see app. I).

OMB staff and EPA officials told us that OMB and the Council of Economic Advisers decided which EOP offices and federal agencies to invite to participate in the working group and, according to participants we interviewed from several agencies, each agency that chose to participate decided which of its internal offices would send representatives. OMB staff stated that any federal agency was welcome to participate in the working group, and EPA officials told us that at least two invited agencies declined to participate. OMB staff recalled that the working group generally included up to several participants from each participating office and agency and numbered approximately two dozen participants in total.

¹⁹We previously reported that four of these EOP offices—the Council on Environmental Quality, Office of Energy and Climate Change, OMB, and Office of Science and Technology Policy—provide high-level policy direction for federal climate change programs and activities and commonly lead formal and informal interagency initiatives on related issues. See GAO, *Climate Change: Improvements Needed to Clarify National Priorities and Better Align Them with Federal Funding Decisions*, [GAO-11-317](#) (Washington, D.C.: May 20, 2011).

Table 2 lists the 12 participating offices and agencies, along with the internal offices they sent to represent them on the working group.

Table 2: Offices and Agencies Participating in the Interagency Working Group on Social Cost of Carbon to Develop the 2010 and 2013 Social Cost of Carbon Estimates

Participating office or agency	2010 estimates	2013 estimates
Executive Office of the President		
Council of Economic Advisers ^a	X	X
Council on Environmental Quality	X	X
National Economic Council	X	X
Office of Energy and Climate Change ^b	X	X
Office of Management and Budget ^a	X	X
Office of Information and Regulatory Affairs		
Office of Science and Technology Policy	X	X
Federal agencies		
Department of Agriculture		
• Office of the Chief Economist	X	X
Department of Commerce ^c		
• International Trade Administration, Office of Competition and Economic Analysis ^d	X	
• National Oceanic and Atmospheric Administration, National Marine Fisheries Service ^e		X
Department of Energy ^f		
• Office of Climate Change Policy and Technology ^g	X	X
Department of Transportation		
• Office of the Secretary	X	X
• Volpe, The National Transportation Systems Center	X	
Department of the Treasury		
• Office of Economic Policy	X	
• Office of International Affairs, Office of Environment and Energy	X	X
Environmental Protection Agency		
• Office of Air and Radiation, Office of Atmospheric Programs	X	X
• Office of Policy, National Center for Environmental Economics	X	X

Source: GAO analysis of information provided by the Office of Management and Budget, Environmental Protection Agency, and Departments of Agriculture, Commerce, Energy, Transportation, and the Treasury. | GAO-14-663

^aThe Council of Economic Advisers and the Office of Management and Budget convened and led the working group to develop the 2010 and 2013 estimates.

^bIn March 2011, the Office of Energy and Climate Change joined the Domestic Policy Council.

^cAn official from the Department of Commerce's Economics and Statistics Administration told us that he attended two working group meetings as an observer during the development of the 2013 estimates, but that he did not review any materials produced by the group or otherwise contribute to the development of the estimates.

^dThe International Trade Administration's Office of Competition and Economic Analysis is now known as the Office of Trade and Economic Analysis.

^eAn official from the Department of Commerce's National Oceanic and Atmospheric Administration told us that she participated in the working group to develop the 2010 estimates while serving on detail to the Office of Science and Technology Policy.

^fA former Administrator of the Energy Information Administration told us that he participated as a technical advisor to the working group to develop the 2010 estimates and not as a representative of the Department of Energy. Participants told us that the Energy Information Administration also sent a representative to some working group meetings as an observer during the development of the 2013 estimates.

^gThe Office of Climate Change Policy and Technology is now known as the Office of Climate, Environment, and Efficiency.

In establishing the working group, several participants told us that OMB and the Council of Economic Advisers made efforts to ensure that the group's members, collectively, brought the necessary technical expertise for developing social cost of carbon estimates. For example, according to these participants and EPA documentation, participants from the EOP offices included individuals with expertise in pertinent topics, such as economics and climate science. The former Deputy Assistant Secretary for Environment and Energy at the Department of the Treasury stated that he was invited to participate in the working group because of his prior experience researching ways to discount costs and benefits across generations. In addition, the former Administrator of the Energy Information Administration told us that he was asked to participate, in part, based on his previous experience evaluating climate models while conducting research with the National Academy of Sciences. According to an OMB staff member, the six participating federal agencies were also responsible for ensuring that they provided adequate technical expertise to the working group. Agency representatives included environmental economists and climate scientists, among other key professionals. According to EPA documentation, participants from EPA also provided technical expertise in climate science, economics, and academic modeling to the broader group, as needed.

When the working group reconvened in 2013 to update the estimates, the same EOP offices and agencies generally participated, although some of the individuals participating on behalf of offices or agencies changed, in part due to individuals changing positions or leaving the government altogether. Also, some participants who previously had been serving details at other participating agencies had returned to their home agencies. For example, certain participants who were on detail to the

Council of Economic Advisers during the development of the 2010 Technical Support Document instead represented EPA on the working group during the development of the 2013 update.

According to the Technical Support Document, the working group was convened under the broad direction of Executive Order 12866 for agencies to assess the costs and benefits of intended regulations.²⁰ In addition, participants from several agencies told us that the executive order was the key requirement driving the working group's effort to develop social cost of carbon estimates. OMB staff stated that, while there is no single requirement or other approach for convening interagency working groups, it is appropriate for OMB to form interagency working groups to collaborate on policy or analytic needs identified under Executive Order 12866. These OMB staff members said that, instead of being organized under a written agreement or other requirements, the working group was an informal interagency working group with no charter or other convening document. According to OMB staff, there was no requirement that the informal working group should document its activities or proceedings, including the meetings held or specific discussions that occurred at each. However, OMB staff and EPA officials stated that all major issues discussed during working group meetings are documented in the Technical Support Document and its 2013 update, which is consistent with the control activities standard in the federal standards for internal control.²¹ We have also reported that interagency working groups use a variety of mechanisms to implement interagency collaborative efforts, including temporary working groups,²² and that not all collaborative arrangements, particularly those that are informal, need to be documented through written guidance and agreements.²³

²⁰The 2013 update to the Technical Support Document adds that Executive Order 13563, issued after the working group developed the 2010 social cost of carbon estimates, commits the administration to regulatory decision making based on the best available science.

²¹GAO, *Standards for Internal Control in the Federal Government*, [GAO/AIMD-00-21.3.1](#) (Washington, D.C.: November 1999).

²²GAO, [GAO-11-317](#); *Managing for Results: Key Considerations for Implementing Interagency Collaborative Mechanisms*, [GAO-12-1022](#) (Washington, D.C.: Sept. 27, 2012); and *Managing for Results: Implementation Approaches Used to Enhance Collaboration in Interagency Groups*, [GAO-14-220](#) (Washington, D.C.: Feb. 14, 2014).

²³[GAO-12-1022](#).

Processes and Methods

Participants told us that the working group's processes and methods reflected three key principles. First, the group used consensus-based decision making. Second, the group relied largely on existing academic literature and models, including technical assistance from outside resources. Third, the group took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available.

Used Consensus-Based Decision Making

All of the participants we spoke with said that the working group used a consensus-based approach for making key decisions on developing the social cost of carbon estimates. Most participants said that the working group's overall approach was open and collegial, and that participants had many opportunities to make contributions and raise issues for discussion that were important to them.

OMB staff stated that the working group did not assign roles or responsibilities, and many participants told us that different working group participants and agencies volunteered to take responsibility for various aspects of the development of the estimates that fell within their particular areas of expertise. For example, OMB staff stated that, while OMB and the Council of Economic Advisers were the official leaders of the working group meetings, all EOP offices that participated played a large role during the meetings, and discussions were informal. According to these staff and other officials we spoke with, participants could generally choose the extent of their involvement, and all participants' contributions were considered equally.

According to many participants, the Council of Economic Advisers coordinated drafting the Technical Support Document, including gathering feedback from working group members. Specifically, they told us that, following the meetings, officials from the Council of Economic Advisers summarized the group discussions to include in the latest draft of the Technical Support Document and circulated draft sections of the Technical Support Document for the working group to review. For example, a participant told us that he raised concerns about whether the Technical Support Document provided adequate information on domestic measures of the social cost of carbon. The participant said that, in response to this feedback, the working group decided to include a separate discussion in the Technical Support Document on estimating domestic benefits and costs. The Technical Support Document states that reported domestic effects should be calculated using a range of values from 7 to 23 percent of the global measure of the social cost of carbon, although it cautions that these values are approximate, provisional, and

Relied on Existing Academic Literature and Models

highly speculative due to limited evidence. None of the participants we spoke with expressed concerns about how their contributions were incorporated into the final Technical Support Document. The participants generally stated that they were satisfied that the final Technical Support Document successfully addressed individual comments on the draft version and the overall consensus of the working group and its participating offices and agencies.

The Technical Support Document states that the main objective of the working group was to develop a range of estimates of the social cost of carbon using a defensible set of modeling inputs based on existing academic literature. Many participants confirmed that the working group relied largely on existing academic literature and models to develop its estimates. According to the Technical Support Document and many participants we spoke with, the working group calculated its estimates using three models that integrate climate and economic data into a single modeling framework for estimating future economic effects resulting from climate change.²⁴ In general, each model translates carbon dioxide emissions scenarios into changes in greenhouse gas concentrations in the atmosphere, greenhouse gas concentrations in the atmosphere into temperature changes, and temperature changes into net economic effects (i.e., damages and benefits). However, each model uses its own methods to estimate these effects. The Technical Support Document states that the three models are frequently cited in peer-reviewed literature. They have also been used in climate assessments by the Intergovernmental Panel on Climate Change—an organization within the United Nations that assesses scientific, technical, and economic information on the effects of climate change. In addition, the National Research Council of the National Academies recognized these three models as three of the most widely used models of their kind.²⁵

Many participants told us that the working group spent most of its meeting time reviewing and discussing academic literature to help decide on

²⁴The three models are Dynamic Integrated Climate and Economy (DICE), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND), and Policy Analysis of the Greenhouse Effect (PAGE). They were first developed in the early 1990s by researchers acknowledged as leaders in their field and are updated regularly based on new developments in climate and economic research.

²⁵National Research Council, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (Washington, D.C.: National Academies Press, 2010).

values for three key modeling inputs to run in each model. The key modeling inputs the working group selected were based on data from prevalent research organizations, such as the Stanford Energy Modeling Forum, and reflected the wide uncertainty in the academic literature, according to the Technical Support Document.²⁶ These inputs were as follows:

- scenarios for future population and economic growth (i.e., gross domestic product) and carbon dioxide emissions,
- a measure of the climate's responsiveness to increased concentrations of greenhouse gases in the atmosphere—known as equilibrium climate sensitivity,²⁷ and
- discount rates.

Several participants told us that different meetings focused on different modeling inputs and included technical presentations by participants with expertise in each technical area. For example, due to their previous experience working with the models, EPA officials made presentations on how each model works. OMB staff stated that the technical presentations focused on the academic materials cited in the Technical Support Document, including dozens of peer-reviewed journal articles. They also said that all technical decisions discussed in the Technical Support Document were arrived at by consensus through this process. Several participants said that a significant amount of the group's discussions focused on selecting discount rates that best reflect the most current academic literature, while also comports with OMB's guidance in Circular A-4. The Technical Support Document cites guidance from Circular A-4 in its discussion of many technical topics, including its selection of discount rates. It states that the discount rate (i.e., 3 percent) used to calculate the central value of the social cost of carbon estimates is consistent with Circular A-4 guidance. Some working group participants told us that they recognized the importance of using OMB guidance, including Circular A-4, in developing the Technical Support Document. The Technical Support Document states that the working group decided

²⁶The Stanford Energy Modeling Forum is an international forum for sharing and facilitating discussions on energy policy and global climate issues among researchers.

²⁷Equilibrium climate sensitivity is the long-term increase in the annual global-average surface temperature from a sustained doubling of the concentration of carbon dioxide in the atmosphere relative to preindustrial levels of the concentration of carbon dioxide in the atmosphere.

to calculate estimates for several discount rates (2.5, 3, and 5 percent) because the academic literature shows that the social cost of carbon is highly sensitive to the discount rate chosen, and because no consensus exists on the appropriate rate. It further states that, in light of such uncertainties, the working group determined that these three discount rates reflect reasonable judgments about the appropriate rate to use. Several participants stated that the working group chose this approach to capture varied concerns and interests, including participants' respective knowledge of the academic literature, on selecting the discount rate.

Once the working group agreed on these modeling inputs, EPA officials supervised their use in running the models to calculate the social cost of carbon estimates. All other model assumptions and features were unchanged by the working group, which weighted each model equally to calculate the final estimates. Several participants stated that an important principle for the leaders of the working group was that the working group reach consensus on the modeling inputs before running the models and agree, in advance, to accept the results based on the inputs selected, whatever the outcome. Through this approach, the working group developed a set of four social cost of carbon estimates for use in regulatory impact analyses. The first three values are based on the average of the estimates produced by all three models and selected modeling inputs at the three discount rates chosen. The fourth value was included to represent higher-than-expected economic impacts from climate change, and it is based on an average of certain values produced by each model at a 3 percent discount rate.²⁸ To capture uncertainties involved in regulatory impact analysis, the Technical Support Document emphasizes the importance of agencies considering all four estimates when conducting analyses.

According to EPA documentation and several participants, groups from outside the federal government did not participate in the working group, but the working group used some outside resources, specifically technical assistance. As noted in the Technical Support Document, the working group explored technical literature in relevant fields for developing the social cost of carbon estimates. Members of the working group

²⁸According to the Technical Support Document, the working group determined the fourth value by combining the values appearing at the furthest reaches of the distributions produced by each model. For this purpose, the working group used values produced from all three models for the 95th percentile at a 3 percent discount rate.

sometimes contacted researchers or developers of key data in an effort to ensure that the working group had a clear understanding of the information and how to use it. For example, according to several participants, members of the working group consulted with lead authors of a chapter on climate sensitivity that appears in the *Fourth Assessment Report of the Intergovernmental Panel on Climate Change*.²⁹ According to the Technical Support Document, after consulting with the chapter authors, the working group was able to make some decisions to assist with statistical analyses needed to develop the social cost of carbon estimates. Many participants stated that the working group also consulted with the developers of the models used by the group to develop the estimates. For example, EPA officials told us that, while they conducted runs for one model that was readily available to the public, they spent a few days training with the developer of a second model before using it to conduct runs. They also contracted with the developer of a third model to run the model according to the decisions reached by the working group. They stated that they ran all of the 2013 estimates themselves, but that they continued to consult with the model developers to do so.

According to many participants and the 2013 update to the Technical Support Document, the only changes made to the models used for the 2013 revisions were those that the model developers incorporated into the latest versions of the models and that were subsequently used in peer-reviewed academic literature. Specifically, the developers updated the academic models to reflect new scientific information, such as in sea level rise and associated damages, resulting in higher estimates.³⁰ The working group did not make changes in the modeling inputs that it used

²⁹Intergovernmental Panel on Climate Change, *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (S. Solomon, et al. [eds.]) (Cambridge, UK: Cambridge University Press, 2007).

³⁰This new scientific information included an explicit representation of sea level rise and associated damages, updated climate change adaptation assumptions, and updated damage functions for agricultural impacts.

Took Steps to Disclose
Limitations and Incorporate
New Information

for the 2010 estimates.³¹ Several participants said that, while the original working group included frequent, hours-long meetings over several months, the working group assembled to discuss the 2013 revisions only met a few times. According to the 2010 Technical Support Document, the working group is committed to updating its estimates as the science and economic understanding of climate change and its impacts on society improve over time.

According to several participants and the Technical Support Document, the working group's processes and methods took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated economic and scientific research became available. The Technical Support Document discusses several limitations of its estimates and areas that the working group identified as being in particular need of additional exploration and research. For example, it points out that none of the three models accounts for damages from wildlife loss or ocean acidification caused by carbon dioxide emissions. Also, the models cannot completely predict how technology may adapt to warmer temperatures. In addition, according to the Technical Support Document, the models may not fully consider the effects of damages due to potential catastrophic events, such as the melting of Antarctic ice sheets. As a result of such limitations, the models may underestimate damages from increased carbon emissions, according to the Technical Support Document. The Technical Support Document states that, as a result of these limitations, the social cost of carbon estimates should continue to evolve as knowledge is gained, and available models improve. Some of the participating agencies have incorporated discussions of these limitations into regulatory impact analyses using social cost of carbon estimates. For example, in a 2012 rule setting pollution standards for certain power plants, EPA noted that

³¹In January 2014, a former coleader of the working group discussed some of the reasons behind this approach in a presentation before the annual meeting of the American Economic Association, a leading economic interest group. See Cass Sunstein, "On Not Revisiting Official Discount Rates: Institutional Inertia and the Social Cost of Carbon" (paper presented at the annual meeting of the American Economic Association, Philadelphia, PA, Jan. 3, 2014). In 2013, another former coleader of the working group published a paper detailing the working group's methodology. See Greenstone, Michael et al., "Developing a Social Cost of Carbon for U.S. Regulatory Analysis: A Methodology and Interpretation," *Review of Environmental Economics and Policy* 7, no. 1: 23-46 (2013).

the social cost of carbon estimates are subject to limitations and uncertainties.³²

Over the years, there have been opportunities for public comment on the various individually developed and working group estimates of the social cost of carbon for regulatory impact analysis, and several participants stated that these estimates were developed with input from the public. Since 2008, agencies have published over three dozen regulatory actions for public comment in the *Federal Register* that use various social cost of carbon estimates in regulatory impact analyses. While some of them specifically sought comments on the development of the social cost of carbon estimates used, and others did not, these regulatory actions were open to public comment, in general, for approximately 60 days and, according to OMB staff and other participants, agencies received many comments on the estimates through this process. Several participants stated that, while they discussed such public comments during working group meetings, individual agencies typically do not coordinate formally with other agencies on their reviews of comments received. According to the Technical Support Document, the working group convened, in part, to consider public comments on issues related to the social cost of carbon. After considering public comments on the interim values that agencies used in several rules, the working group developed the Technical Support Document, according to these participants and to the Technical Support Document. Several participants told us that the working group decided to revise the estimates for the first time in 2013 after agencies received a number of public comments encouraging revisions because the models used to develop the 2010 estimates had been subsequently updated and used in peer-reviewed academic literature. OMB staff stated that this theme was reflected in several public comments on regulations using the 2010 estimates.

In November 2013, OMB published a request in the *Federal Register* for public comments on all aspects of the Technical Support Document and

³²National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304 (Feb. 16, 2012).

its use of the models to develop estimates of the social cost of carbon.³³ The notice stated that OMB is particularly interested in comments on the selection of the models for use in developing the estimates, how the distribution of estimates should be represented in regulatory impact analyses, and the strengths and limitations of the overall approach. OMB staff told us that they decided to issue the request in response to calls for additional transparency, and that they received over 100 unique comments and thousands of identical form-letter comments in response to the request. They said that, since they were still reviewing the comments received, they had not yet decided on steps for responding to them, but that they expect to review them with the working group to determine whether they could inform future updates to the Technical Support Document. OMB staff stated that they have already made most of the comments publicly available online at <http://www.regulations.gov/> and that all of the comments would be made available soon.

The Technical Support Document states that the working group would regularly revisit the social cost of carbon estimates as new information becomes available due to improved scientific and economic research. The Technical Support Document set a goal of revisiting the estimates within 2 years, or when substantially updated models become available. Many participants told us that, to revise the estimates in 2013, the working group met only a few times and mostly for participants from EPA to present information about updates made to the models since the group last met in 2010. The updates touched on a variety of issues, including how some models represent damages from sea level rise. The 2013 update to the Technical Support Document states that it acknowledges the continued limitations described in the original Technical Support Document, and that it updates the estimates based on new versions of the underlying models without revisiting the working group's decisions on modeling inputs. Several participants stated that they reviewed drafts of the 2013 update to the Technical Support Document, but that there was little new information to review because only the models had been updated. In addition to stating that the working group would regularly

³³Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order No. 12866, 78 Fed. Reg. 70,586 (Nov. 26, 2013). In January 2014, OMB extended the public comment period through February 26, 2014. See Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866, 79 Fed. Reg. 4359 (Jan. 27, 2014).

revisit its estimates, the Technical Support Document states that the working group will continue to support research to improve the estimates and hopes to develop methods to value other greenhouse gases as part of its ongoing work.³⁴

Agency Comments

We provided a draft of this report for review and comment to the Departments of Agriculture, Commerce, Energy, Transportation, and the Treasury; EPA; and OMB. Only the Department of the Treasury provided written comments, which we received on July 14, 2014, and are reproduced in appendix II; in its written comments, the Department of the Treasury stated that the draft report does a good job of capturing the interagency process through which the estimates of the social cost of carbon were developed. In oral comments provided on July 15, 2014, OMB staff confirmed that OMB generally agreed with the report findings. OMB staff also provided technical comments, which we incorporated into the report, as appropriate. The Department of Energy and EPA provided technical comments only, which we incorporated into the report, as appropriate. In e-mails received on July 1, July 9, and July 14, 2014, respectively, the liaisons from the Departments of Agriculture, Commerce, and Transportation stated that the departments did not have any comments on the draft report.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies to the appropriate congressional committees; the Secretaries of Agriculture, Commerce, Energy, Transportation, and the Treasury; the Administrator of EPA; the

³⁴In late 2010 and early 2011, EPA and the Department of Energy sponsored two workshops on valuing climate change damages for regulatory analysis. The agencies reported that they sponsored the workshops to prepare for and inform future working group activities. See ICF International, *Workshop Report: Improving the Assessment and Valuation of Climate Change Impacts for Policy and Regulatory Analysis – Part 1* (January 2011); summary of workshop sponsored by EPA and the Department of Energy and titled “Modeling Climate Change Impacts and Associated Economic Damages” (Washington, D.C.: Nov. 18-19, 2010) and *Workshop Report: Improving the Assessment and Valuation of Climate Change Impacts for Policy and Regulatory Analysis – Part 2* (March 2011); summary of workshop sponsored by EPA and the Department of Energy and titled “Research on Climate Change Impacts and Associated Economic Damages” (Washington, D.C., Jan. 27-28, 2011).

Director of OMB; and other interested parties. In addition, the report will be available at no charge on the GAO website at <http://www.gao.gov>.

If you or your staff members have any questions about this report, please contact me at (202) 512-3841 or gomezj@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. Key contributors to this report are listed in appendix III.

A handwritten signature in black ink, reading "Alfredo Gómez". The signature is written in a cursive style with a large, stylized "A" and "G".

J. Alfredo Gómez
Director, Natural Resources and Environment

Appendix I: Regulatory Actions, by Agency and Type of Social Cost of Carbon Estimates Used, 2008-2014

This appendix lists regulatory actions from 2008 to 2014 and the type of social cost of carbon estimates used (i.e., individually developed, interim, 2010, or 2013) in the actions' regulatory impact analyses. For each regulatory action, table 3 lists the date published in the *Federal Register*, the agency conducting the action, the name and status of the rule associated with the action, and the action's citation in the *Federal Register*.

Table 3: Regulatory Actions, by Agency and Type of Social Cost of Carbon Estimates Used in the Regulatory Impact Analysis, 2008-2014

Date published in the <i>Federal Register</i>	Agency	Rule	Status of rule	<i>Federal Register</i> citation
Individually developed agency estimates				
May 2, 2008	Department of Transportation (Transportation), National Highway Traffic Safety Administration (NHTSA)	Average Fuel Economy Standards, Passenger Cars and Light Trucks; Model Years 2011-2015	Proposed	73 Fed. Reg. 24,352
July 30, 2008	Environmental Protection Agency (EPA)	Regulating Greenhouse Gas Emissions Under the Clean Air Act	Advanced Notice of Proposed Rulemaking	73 Fed. Reg. 44,354
Aug. 25, 2008	Department of Energy (Energy)	Energy Conservation Program for Commercial and Industrial Equipment: Energy Conservation Standards for Commercial Ice-Cream Freezers; Self-Contained Commercial Refrigerators, Commercial Freezers, and Commercial Refrigerator-Freezers Without Doors; and Remote Condensing Commercial Refrigerators, Commercial Freezers, and Commercial Refrigerator-Freezers	Proposed	73 Fed. Reg. 50,072
Oct. 7, 2008	Energy	Energy Conservation Program for Commercial and Industrial Equipment: Packaged Terminal Air Conditioner and Packaged Terminal Heat Pump Energy Conservation Standards	Final	73 Fed. Reg. 58,772

**Appendix I: Regulatory Actions, by Agency
and Type of Social Cost of Carbon Estimates
Used, 2008-2014**

Date published in the Federal Register	Agency	Rule	Status of rule	Federal Register citation
Oct. 17, 2008	Energy	Energy Conservation Program: Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Electric and Gas Kitchen Ranges and Ovens, and Microwave Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers)	Proposed	73 Fed. Reg. 62,034
Jan. 9, 2009	Energy	Energy Conservation Program for Commercial and Industrial Equipment: Energy Conservation Standards for Commercial Ice- Cream Freezers; Self-Contained Commercial Refrigerators, Commercial Freezers, and Commercial Refrigerator-Freezers Without Doors; and Remote Condensing Commercial Refrigerators, Commercial Freezers, and Commercial Refrigerator- Freezers	Final	74 Fed. Reg. 1092
Mar. 30, 2009	Transportation, NHTSA	Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011	Final	74 Fed. Reg. 14,196
Apr. 8, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers)	Final	74 Fed. Reg. 16,040
Apr. 13, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for General Service Fluorescent Lamps and Incandescent Reflector Lamps	Proposed	74 Fed. Reg. 16,920
May 26, 2009	EPA	Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program	Proposed	74 Fed. Reg. 24,904
May 29, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for Refrigerated Bottled or Canned Beverage Vending Machines	Proposed	74 Fed. Reg. 26,020

**Appendix I: Regulatory Actions, by Agency
and Type of Social Cost of Carbon Estimates
Used, 2008-2014**

Date published in the <i>Federal Register</i>	Agency	Rule	Status of rule	<i>Federal Register</i> citation
July 14, 2009	Energy	Energy Conservation Program: Energy Conservation Standards and Test Procedures for General Service Fluorescent Lamps and Incandescent Reflector Lamps	Final	74 Fed. Reg. 34,080
July 22, 2009	Energy	Energy Conservation Program for Certain Industrial Equipment: Energy Conservation Standards and Test Procedures for Commercial Heating, Air-Conditioning, and Water-Heating Equipment	Final	74 Fed. Reg. 36,312
Interim governmentwide estimates				
Aug. 31, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for Refrigerated Bottled or Canned Beverage Vending Machines	Final	74 Fed. Reg. 44,914
Sep. 28, 2009	EPA and Transportation, NHTSA	Proposed Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards	Proposed	74 Fed. Reg. 49,454
Nov. 9, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers)	Supplemental Notice of Proposed Rulemaking	74 Fed. Reg. 57,738
Nov. 24, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for Small Electric Motors	Proposed	74 Fed. Reg. 61,410
Dec. 11, 2009	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters	Proposed	74 Fed. Reg. 65,852
Jan. 8, 2010	Energy	Energy Conservation Program: Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers)	Final	75 Fed. Reg. 1122

**Appendix I: Regulatory Actions, by Agency
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Used, 2008-2014**

Date published in the Federal Register	Agency	Rule	Status of rule	Federal Register citation
Mar. 26, 2010	EPA	Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program	Final	75 Fed. Reg. 14,670
June 21, 2010	EPA	Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities	Proposed	75 Fed. Reg. 35,128
2010 governmentwide estimates				
Mar. 9, 2010	Energy	Energy Conservation Program: Energy Conservation Standards for Small Electric Motors	Final	75 Fed. Reg. 10,874
Apr. 16, 2010	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Water Heaters, Direct Heating Equipment, and Pool Heaters	Final	75 Fed. Reg. 20,112
May 7, 2010	EPA and Transportation, NHTSA	Light Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards	Final	75 Fed. Reg. 25,324
May 28, 2010	Transportation, Federal Aviation Administration	Automatic Dependent Surveillance—Broadcast (ADS-B) Out Performance Requirements to Support Air Traffic Control (ATC) Service	Final	75 Fed. Reg. 30,160
Aug. 2, 2010	EPA	Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone	Proposed	75 Fed. Reg. 45,210
Sep. 9, 2010	EPA	National Emission Standards for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants	Final	75 Fed. Reg. 54,970
Oct. 14, 2010	EPA	Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units	Proposed	75 Fed. Reg. 63,260
Nov. 30, 2010	EPA and Transportation, NHTSA	Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles	Proposed	75 Fed. Reg. 74,152

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Used, 2008-2014**

Date published in the <i>Federal Register</i>	Agency	Rule	Status of rule	<i>Federal Register</i> citation
Mar. 14, 2011	EPA	National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants	Supplemental Proposed Rule	76 Fed. Reg. 13,852
Mar. 21, 2011	EPA	Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units	Final	76 Fed. Reg. 15,372
Mar. 21, 2011	EPA	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	Final	76 Fed. Reg. 15,608
Apr. 11, 2011	Energy	Energy Conservation Program: Energy Conservation Standards for Fluorescent Lamp Ballasts	Proposed	76 Fed. Reg. 20,090
Apr. 21, 2011	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers and Room Air Conditioners	Direct Final	76 Fed. Reg. 22,454
June 27, 2011	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Furnaces and Residential Central Air Conditioners and Heat Pumps	Direct Final	76 Fed. Reg. 37,408
Aug. 8, 2011	EPA	Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals ^a	Final	76 Fed. Reg. 48,208
Sep. 15, 2011	EPA and Transportation, NHTSA	Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles	Final	76 Fed. Reg. 57,106
Sep. 15, 2011	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers	Final	76 Fed. Reg. 57,516
Nov. 14, 2011	Energy	Energy Conservation Program: Energy Conservation Standards for Fluorescent Lamp Ballasts	Final	76 Fed. Reg. 70,548
Dec. 1, 2011	EPA and Transportation, NHTSA	2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards	Proposed	76 Fed. Reg. 74,854

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Used, 2008-2014**

Date published in the Federal Register	Agency	Rule	Status of rule	Federal Register citation
Dec. 23, 2011	EPA	Commercial and Industrial Solid Waste Incineration Units: Reconsideration and Proposed Amendments; Non-Hazardous Secondary Materials That Are Solid Waste	Proposed	76 Fed. Reg. 80,452
Jan. 17, 2012	Energy	Energy Conservation Program for Certain Industrial Equipment: Energy Conservation Standards and Test Procedures for Commercial Heating, Air-Conditioning, and Water-Heating Equipment	Proposed	77 Fed. Reg. 2356
Feb. 10, 2012	Energy	Energy Conservation Program: Energy Conservation Standards for Distribution Transformers	Proposed	77 Fed. Reg. 7282
Feb. 14, 2012	Energy	Energy Conservation Program: Energy Conservation Standards for Standby Mode and Off Mode for Microwaves	Supplemental Notice of Proposed Rulemaking	77 Fed. Reg. 8526
Feb. 16, 2012	EPA	National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units	Final	77 Fed. Reg. 9304
Mar. 27, 2012	Energy	Energy Conservation Program: Energy Conservation Standards for Battery Chargers and External Power Supplies	Proposed	77 Fed. Reg. 18,478
Apr. 13, 2012	EPA	Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units	Proposed	77 Fed. Reg. 22,392
May 30, 2012	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers	Direct Final	77 Fed. Reg. 31,918
May 31, 2012	Energy	Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers	Direct Final	77 Fed. Reg. 32,308
Oct. 15, 2012	EPA and Transportation, NHTSA	2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards	Final	77 Fed. Reg. 62,624

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Used, 2008-2014**

Date published in the <i>Federal Register</i>	Agency	Rule	Status of rule	<i>Federal Register</i> citation
Apr. 18, 2013	Energy	Energy Conservation Program: Energy Conservation Standards for Distribution Transformers	Final	78 Fed. Reg. 23,336
June 7, 2013	EPA	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category	Proposed	78 Fed. Reg. 34,432
2013 revised governmentwide estimates				
June 17, 2013	Energy	Energy Conservation Program: Energy Conservation Standards for Standby Mode and Off Mode for Microwave Ovens	Final	78 Fed. Reg. 36,316
Aug. 20, 2013	Energy	Energy Conservation Program: Energy Conservation Standards for Metal Halide Lamp Fixtures	Proposed	78 Fed. Reg. 51,464
Sep. 11, 2013	Energy	Energy Conservation Program: Energy Conservation Standards for Walk-In Coolers and Freezers	Proposed	78 Fed. Reg. 55,782
Sep. 11, 2013	Energy	Energy Conservation Program: Energy Conservation Standards for Commercial Refrigeration Equipment	Proposed	78 Fed. Reg. 55,890
Oct. 25, 2013	Energy	Energy Conservation Program for Consumer Products: Energy Conservation Standards for Residential Furnace Fans	Proposed	78 Fed. Reg. 64,068
Dec. 6, 2013	Energy	Energy Conservation Program: Energy Conservation Standards for Commercial and Industrial Electric Motors	Proposed	78 Fed. Reg. 73,590
Jan. 8, 2014	EPA	Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units	Proposed	79 Fed. Reg. 1430
Feb. 10, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for Metal Halide Lamp Fixtures	Final	79 Fed. Reg. 7746
Feb. 10, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for External Power Supplies	Final	79 Fed. Reg. 7846
Mar. 4, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for Commercial Clothes Washers	Proposed	79 Fed. Reg. 12,302

**Appendix I: Regulatory Actions, by Agency
and Type of Social Cost of Carbon Estimates
Used, 2008-2014**

Date published in the <i>Federal Register</i>	Agency	Rule	Status of rule	<i>Federal Register</i> citation
Mar. 17, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for Automatic Commercial Ice Makers	Proposed	79 Fed. Reg. 14,846
Mar. 28, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for Commercial Refrigeration Equipment	Final	79 Fed. Reg. 17,726
Apr. 29, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for General Service Fluorescent Lamps and Incandescent Reflector Lamps	Proposed	79 Fed. Reg. 24,068
May 29, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for Commercial and Industrial Electric Motors	Final	79 Fed. Reg. 30,934
June 3, 2014	Energy	Energy Conservation Program: Energy Conservation Standards for Walk-In Coolers and Freezers	Final	79 Fed. Reg. 32,050
June 18, 2014	EPA	Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units	Proposed	79 Fed. Reg. 34,830

Sources: Environmental Protection Agency and *Federal Register*. | GAO-14-663

Notes:

Regulatory actions in this table are as of June 18, 2014.

In 2008 and early 2009, individual estimates of the social cost of carbon were developed by each agency and typically based on estimates published in academic literature. The interim governmentwide estimates were developed in early 2009 by the Interagency Working Group on Social Cost of Carbon and derived from an average of selected estimates published in academic literature. The 2010 governmentwide estimates were developed by the Interagency Working Group on Social Cost of Carbon and issued in its February 2010 Technical Support Document. The 2013 revised governmentwide estimates were developed by the Interagency Working Group on Social Cost of Carbon and issued in a May 2013 update to the Technical Support Document, which was reissued with minor technical corrections in November 2013.

^aSIP refers to State Implementation Plan.

Appendix II: Comments from the Department of the Treasury



DEPARTMENT OF THE TREASURY
WASHINGTON, D.C.

JUL 14 2014

TO: Director J. Alfredo Gomez, Government Accountability Office

FROM: Leonardo Martinez-Diaz, Deputy Assistant Secretary for Energy and Environment

RE: Draft report on Development of Social Cost of Carbon Estimate (361544)

Dear Director Gomez,

Thank you for the opportunity to review the draft report on the Development of the Social Cost of Carbon Estimates (361544). The report does a good job of capturing the interagency process through which the estimates of the social cost of carbon were developed. We have no further comments on the draft.

Sincerely,

A handwritten signature in black ink, appearing to read "Leonardo Martinez-Diaz", written over a large, stylized "X" mark.

Leonardo Martinez-Diaz

Appendix III: GAO Contact and Staff Acknowledgments

GAO Contact

J. Alfredo Gómez, (202) 512-3841, or gomezj@gao.gov

Staff Acknowledgments

In addition to the individual named above, Janet Frisch (Assistant Director), Elizabeth Beardsley, Stephanie Gaines, Cindy Gilbert, Chad M. Gorman, Tim Guinane, Patricia Moye, Susan Offutt, Alison O'Neill, and Kiki Theodoropoulos made key contributions to this report.

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Exhibit 11



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUN 06 2011

ASSISTANT ADMINISTRATOR
FOR ENFORCEMENT AND
COMPLIANCE ASSURANCE

Mr. Jose W. Fernandez
Assistant Secretary
Economic, Energy and Business Affairs
U.S. Department of State
Washington, DC 20520

Dr. Kerri-Ann Jones
Assistant Secretary
Oceans and International Environmental and Scientific Affairs
U.S. Department of State
Washington, DC 20520

Dear Mr. Fernandez and Dr. Jones:

In accordance with our authorities under the National Environmental Policy Act (NEPA), the Council on Environmental Quality (CEQ) NEPA regulations, and Section 309 of the Clean Air Act, EPA has reviewed the Supplemental Draft Environmental Impact Statement (SDEIS) for TransCanada's proposed Keystone XL Project ("Project").

EPA reviewed the Draft Environmental Impact Statement (DEIS) for this project and submitted comments in July of 2010. At that time EPA rated the DEIS as "Inadequate-3" because potentially significant impacts were not evaluated and additional information and analyses were necessary to ensure that the EIS fully informed decision makers and the public about potential consequences of the Keystone XL Project. Since that time, the State Department has worked diligently to develop additional information and analysis in response to EPA's comments and the large number of other comments received on the DEIS. The State Department also made a very constructive decision to seek further public review and comment through publication of the SDEIS, to help the public and decision makers carefully weigh the environmental costs and benefits of transporting oil sands crude from Canada to delivery points in Oklahoma and Texas. The consideration of the environmental impacts associated with constructing and operating this proposed pipeline is especially important given that current excess pipeline capacity for transporting oil sands crude to the United States will likely persist until after 2020, as noted in the SDEIS.

While the SDEIS has made progress in responding to EPA's comments on the DEIS and providing information necessary for making an informed decision, EPA believes additional analysis is necessary to fully respond to our earlier comments and to ensure a full evaluation of

the potential impacts of proposed Project, and to identify potential means to mitigate those impacts. As EPA and the State Department have discussed many times, EPA recommends that the State Department improve the analysis of oil spill risks and alternative pipeline routes, provide additional analysis of potential impacts to communities along the pipeline route and adjacent to refineries and the associated environmental justice concerns, together with ways to mitigate those impacts, improve the discussion of lifecycle greenhouse gas emissions (GHGs) associated with oil sands crude, and improve the analysis of potential impacts to wetlands and migratory bird populations. We are encouraged by the State Department's agreement to include some of these additional analyses in the Final Environmental Impact Statement (Final EIS). We have noted those agreements in this letter, and look forward to working with you to develop these analyses for the Final EIS.

Pipeline Safety/Oil Spill Risks

EPA is the lead federal response agency for responding to oil spills occurring in and around inland waters. As part of that responsibility, we have considerable experience working to prevent and respond to oil spills. Pipeline oil spills are a very real concern, as we saw during the two pipeline spills in Michigan and Illinois last summer. Just in the last month, the Keystone Pipeline experienced two leaks (in North Dakota and Kansas), one of which was brought to the company's attention by a local citizen. These leaks resulted in shut-downs and issuance of an order to TransCanada from the Pipeline and Hazardous Materials Safety Administration (PHMSA), requiring that corrective measures be taken prior to the subsequently approved restart of operations. PHMSA's Order of June 3, 2011 for the Keystone Pipeline – which also carries Canadian oil sands crude oil and is operated by the same company as the proposed Keystone XL Project – was based on the hazardous nature of the product that the pipeline transports and the potential that the conditions causing the failures that led to the recent spills were present elsewhere on the pipeline. These events, which occurred after EPA's comment letter on the DEIS, underscore the comments about the need to carefully consider both the route of the proposed Keystone XL Pipeline and appropriate measures to prevent and detect a spill.

We have several recommendations for additional analyses that relate to the potential for oil spills, as well as the potential impacts and implications for response activities in the event of a pipeline leak or rupture. We recommend and appreciate your agreement that the Final EIS use data from the National Response Center, which reports a more comprehensive set of historical spill events than the Pipeline and Hazardous Material Safety Administration's incident database, to assess the risk of a spill from the proposed pipeline. With respect to the spill detection systems proposed by the applicant, we remain concerned that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, we also appreciate your agreement that the Final EIS consider additional measures to reduce the risks of undetected leaks. For example, requiring ground-level inspections of valves and other parts of the system several times per year, in addition to aerial patrols, could improve the ability to detect leaks or spills and minimize any damage.

The SDEIS indicates that there may be a "minor" increase in the number of mainline valves installed to isolate pipeline segments and limit impacts of a spill, compared to what was

originally reported in the DEIS (SDEIS, pg. 2-4). However, no detailed information or decision criteria are provided with regard to the number of valves, or their location. In order to evaluate potential measures to mitigate accidental releases, we appreciate your agreement to provide additional information in the Final EIS on the number and location of the valves that will be installed and to evaluate the feasibility of increasing the number of valves in more vulnerable areas. For example, it may be appropriate to increase the number of valves where the water table is shallow, or where an aquifer is overlain by highly permeable soils, such as the Ogallala aquifer. We also recommend consideration of external pipe leak detection systems in these areas to improve the ability to detect pinhole (and greater) leaks that could be substantial, yet below the sensitivity of the currently proposed leak detection systems. In addition, while we understand that valves are not proposed to be located at water crossings that are less than 100 feet wide, we recommend that the Final EIS nevertheless consider the potential benefits of installing valves at water crossings less than 100 feet wide where there are sensitive aquatic resources.

Predicting the fate and transport of spilled oil is also important to establish potential impacts and develop response strategies. While the SDEIS provides additional information about the different classes of crude oils that may be transported, we recommend the Final EIS evaluate each class of crude that will be transported, how it will behave in the environment, and qualitatively discuss the potential issues associated with responding to a spill given different types of crude oils and diluents used.

With regard to the chemical nature of the diluents that are added to reduce the viscosity of bitumen, the SDEIS states “the exact composition may vary between shippers and is considered proprietary information” (SDEIS, pg. 3-104). We believe an analysis of potential diluents is important to establish the potential health and environmental impacts of any spilled oil, and responder/worker safety, and to develop response strategies. In the recent Enbridge oil spill in Michigan, for example, benzene was a component of the diluent used to reduce the viscosity of the oil sands crude so that it could be transported through a pipeline. Benzene is a volatile organic compound, and following the spill in Michigan, high benzene levels in the air prompted the issuance of voluntary evacuation notices to residents in the area by the local county health department. Similarly, although the SDEIS provides additional information on the potential impact of spills on groundwater, we recommend that the Final EIS improve the risk assessment by including specific information on the groundwater recharge areas along the pipeline route, recognizing that these areas are more susceptible to groundwater contamination from oil spills.

We appreciate that the SDEIS provides additional information about the feasibility of alternative pipeline routes that would reduce the risk of adverse impacts to the Ogallala aquifer, by re-routing the pipeline so it does not cross the aquifer. Many commenters, including EPA, expressed concerns over the potential impacts to this important resource during the review of the DEIS. If a spill did occur, the potential for oil to reach groundwater in these areas is relatively high given shallow water table depths and the high permeability of the soils overlying the aquifer. In addition, we are concerned that crude oil can remain in the subsurface for decades, despite efforts to remove the oil and natural microbial remediation.

However, the SDEIS concludes that the alternative routes that avoid the Ogallala aquifer are not reasonable, and consequently does not provide a detailed evaluation of the environmental impacts of routes other than the applicant's proposed route. The SDEIS indicates that no other alternatives are considered in detail because, in part, they do not offer an overall environmental advantage compared to other routes. In support of this conclusion the SDEIS presents a limited analysis of the potential environmental impacts of the alternative routes and offers qualitative judgments about the relative severity of impacts to different resources, e.g., considering potential impacts from spills to the Ogallala aquifer less important than impacts to surface waters from a spill associated with an additional crossing of the Missouri River. We think this limited analysis does not fully meet the objectives of NEPA and CEQ's NEPA regulations, which provide that agencies rigorously explore and objectively evaluate reasonable alternatives. CEQ guidance states that reasonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense.¹ Recognizing the regional significance of these groundwater resources, we recommend that the State Department re-evaluate the feasibility of these alternative routes and more clearly outline the environmental, technical and economic reasons for not considering other alternative routes in more detail as part of the NEPA analysis.

Oil Spill Impacts on Affected Communities and Environmental Justice Concerns

The communities facing the greatest potential impact from spills are of course the communities along the pipeline route. We are concerned that the SDEIS does not adequately recognize that some of these communities may have limited emergency response capabilities and consequently may be more vulnerable to impacts from spills, accidents and other releases. This is particularly likely to be true of minority, low-income and Tribal communities or populations along the pipeline route. We appreciate your agreement to address this issue in the Final EIS by clarifying the emergency response capability of each county along the pipeline route using the plans produced by Local Emergency Planning Committees. We also appreciate your agreement to identify potential mitigation measures in the Final EIS based on this information. We look forward to working with your staff to identify data sources and approaches for addressing these issues.

As part of this analysis, we are concerned that the SDEIS may have underestimated the extent to which there are communities along the pipeline with less capacity to respond to spills and potentially associated health issues, particularly minority, low-income or Tribal communities. We appreciate your agreement to re-evaluate in the Final EIS which communities may have such capacity issues by adopting the more commonly-used threshold of 20% higher low-income, minority or Tribal population compared to the general population, instead of the 50% used in the SDEIS.

With respect to data on access to health care, we are encouraged that the SDEIS provided critically important information on medically underserved areas and on health professional shortage areas. We will provide recommendations on methods to present this data to make it

¹ 40 CFR 1502.14; "Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations," 46 FR 18026 (1981) - Question 2a: Alternatives Outside the Capability of Applicant or Jurisdiction of Agency.

more meaningful to reviewers and will work with your staff as you move towards publishing a Final EIS.

The SDEIS does recognize that minority, low-income or Tribal populations may be more vulnerable to health impacts from an oil spill, and we appreciate the applicant's commitment to provide an alternative water supply "if an accidental release from the proposed Project that is attributable to Keystone's actions contaminates groundwater or surface water used as a source of potable water or for irrigation or industrial purposes..." (SDEIS, pg. 3-154). Further, the SDEIS states that impacts would be mitigated by the applicant's liability for costs associated with cleanup, restoration and compensation for any release that could affect surface water (SDEIS, pg. 3-154). We believe that this mitigation measure should also apply for releases that could affect groundwater. Finally, we recommend that the Final EIS evaluate additional mitigation measures that would avoid and minimize potential impacts through all media (i.e., surface and ground water, soil, and air) to minority, low-income and Tribal populations rather than rely solely on after-the-fact compensation measures. Some examples of additional mitigation include developing a contingency plan before operations commence for emergency response and remedial efforts to control the contamination. This would also include providing notification to individuals affected by soil or groundwater contamination, ensuring the public is knowledgeable and aware of emergency procedures and contingency plans (including posting procedures in high traffic visibility areas), and providing additional monitoring of air emissions and conducting medical monitoring and/or treatment responses where necessary.

Environmental and Health Impacts to Communities Adjacent to Refineries

We are also concerned with the conclusion that there are no expected disproportionate adverse impacts to minority or low-income populations located near refineries that are expected to receive the oil sands crude, particularly because many of these communities are already burdened with large numbers of high emitting sources of air pollutants. It is not self-evident that the addition of an 830,000 barrels per day capacity pipeline from Canada to refineries in the Gulf Coast will have no effect on emissions from refineries in that area. We recommend that the Final EIS re-examine the potential likelihood of increased refinery emissions, and provide a clearer analysis of potential environmental and health impacts to communities from refinery air emissions and other environmental stressors. As part of this re-evaluation, we encourage the State Department to provide more opportunities for people in these potentially affected communities to have meaningful engagement, including additional public meetings, particularly in Port Arthur, Texas, before publication of the Final EIS. Public meetings in these potentially affected communities provide an opportunity for citizens to present their concerns, and also for the State Department to clearly explain its analysis of potential impacts associated with the proposed project to the people potentially affected.

Lifecycle GHG Emissions

We appreciate the State Department's efforts to improve the characterization of lifecycle GHG emissions associated with Canadian oil sands crude. The SDEIS confirms, for example, that Canadian oil sands crude are GHG-intensive relative to other types of crude oil, due primarily to increased emissions associated with extraction and refining.

The SDEIS also includes an important discussion of lifecycle GHG emissions associated with oil sands crude and provides quantitative estimates of potential incremental impacts associated with the proposed Project. For example, the SDEIS (pg. 3-198) states that under at least one scenario, additional annual lifecycle GHG emissions associated with oil sands crude compared to Middle East Sour crude are 12 to 23 million metric tons of CO₂ equivalent (CO₂-e) at the proposed Project pipeline's full capacity (roughly the equivalent of annual emissions from 2 to 4 coal-fired power plants).² While we appreciate the inclusion of such estimates, EPA believes that the methodology used by the State Department and its contractors to calculate those estimates may underestimate the values at the high-end of the ranges cited in the lifecycle GHG emissions discussion by approximately 20 percent. We will continue to work with your staff to address this concern as you move towards publishing a Final EIS.

Further, in discussing these lifecycle GHG emissions, the SDEIS concludes "on a global scale, emissions are not likely to change" (SDEIS, pg. 3-197). We recommend against comparing GHG emissions associated with a single project to global GHG emission levels. As recognized in CEQ's draft guidance concerning the consideration of GHG emissions in NEPA analyses, "[T]he global climate change problem is much more the result of numerous and varied sources, each of which might seem to make a relatively small addition to global atmospheric GHG concentrations."³

Moreover, recognizing the proposed Project's lifetime is expected to be at least fifty years, we believe it is important to be clear that under at least one scenario, the extra GHG emissions associated with this proposed Project may range from 600 million to 1.15 billion tons CO₂-e, assuming the lifecycle analysis holds over time (and using the SDEIS' quantitative estimates as a basis). In addition, we recommend that the Final EIS explore other means to characterize the impact of the GHG emissions, including an estimate of the "social cost of carbon" associated with potential increases of GHG emissions.⁴ The social cost of carbon includes, but is not limited to, climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. Federal agencies use the social cost of carbon to incorporate the social benefits of reducing CO₂ emissions into analyses of regulatory actions that have a marginal impact on cumulative global emissions; the social cost of carbon is also used to calculate the negative impacts of regulatory actions that increase CO₂ emissions.

Finally, we continue to be concerned that the SDEIS does not discuss opportunities to mitigate the entire suite of GHG emissions associated with constructing the proposed Project. We appreciate your agreement to identify practicable mitigation measures in the Final EIS for

² <http://www.epa.gov/cleanenergy/energy-resources/calculator.html>

³ "Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions," (February 18, 2010)

⁴ "Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866;" Interagency Working Group on Social Cost of Carbon, United States Government, February 2010. Presents four estimates of estimated monetized damages associated with a ton of CO₂ released in 2010 (\$5, \$21, \$35, \$65) (\$2007); these estimates grow over time and are associated with different discount rates.

GHG emissions associated with operation of the pipeline in the United States. As part of that analysis, we recommend consideration of opportunities for energy efficiency and utilization of green power for pipeline operations. In addition, we recommend a discussion of mitigation approaches for GHG emissions from extraction activities that are either currently or could be employed to help lower lifecycle GHG emissions to levels closer to those of conventional crude oil supplies. We recommend that this discussion include a detailed description of efforts ongoing and under consideration by producers, as well as the government of Alberta, to reduce GHG emissions from oil sands production.

Wetlands Impacts

EPA co-administers the Clean Water Act Section 404 regulatory program, which regulates the discharge of dredged or fill material into waters of the United States, including wetlands. While we appreciate that the U.S. Army Corps of Engineers is responsible for day-to-day processing of permit applications, our review of aerial photography recently posted on the Project's website indicates that the DEIS may have underestimated the extent of ecologically valuable bottomland hardwood wetlands in Texas. We appreciate your agreement to evaluate these wetland estimates in the Final EIS and to display the location of the bottomland hardwood wetlands with maps and aerial photography. Given their ecological importance, we recommend the same evaluation be done for prairie pothole wetlands that may be impacted by the proposed Project. EPA also recommends that the Final EIS discuss whether it is possible to make further pipeline route variations to avoid both bottomland hardwood and prairie pothole wetlands.

Our review of the aerial photography also indicates that there may be numerous wetland crossings that would impact more than 0.5 acres of wetlands, which is the upper threshold for impacts under the US Army Corps of Engineers' (Corps) nationwide general permit for utility line crossings in waters of the United States. In that light, and recognizing that there will be several hundred acres of wetlands affected along the entire pipeline route, we recommend that the Corps review the proposed wetland impacts as a single project requiring an individual Clean Water Act Section 404 permit. Consolidating each of these crossings into one individual permit review would also provide for more transparency as to the project impacts and allow for more effective mitigation planning, as well as compliance monitoring of the entire project.

Finally, we appreciate your agreement to provide a discussion of potential mitigation measures for project activities that permanently convert forested wetlands to herbaceous wetlands. We continue to recommend providing a conceptual wetland mitigation plan in the Final EIS, including a monitoring component that would, for a specified period of time, direct field evaluations of those wetlands crossed by the pipeline (and mitigation sites) to ensure wetland functions and values are recovering. We also recommend that the Final EIS evaluate the feasibility of using approved mitigation banks to compensate for wetlands impacts.

Migratory Birds

The SDEIS includes a summary of regulatory and other programs aimed at protecting migratory bird populations that may be affected by oil sands extraction activities in Canada. However, we recommend that the Final EIS provide additional information that would address

potential impacts to specific migratory species, with an emphasis on already-vulnerable species, and we appreciate your agreement to provide that information in the Final EIS. Data found in the North American Breeding Bird Survey (a partnership between the U.S. Geological Survey's Patuxent Wildlife Research Center and the Canadian Wildlife Service's National Wildlife Research Center), which monitors bird populations and provides population trend estimates, should be helpful. We also recommend that the Final EIS discuss mitigation measures that are either currently or could be employed for identified impacts.

Conclusion

Based on our review, we have rated the SDEIS as "Environmental Objections - Insufficient Information (EO-2)" (see enclosed "Summary of Rating Definitions and Follow-up Actions"). As explained in this letter, we have a number of concerns regarding the potential environmental impacts of the proposed Project, as well as the level of analysis and information provided concerning those impacts. Our concerns include the potential impacts to groundwater resources from spills, as well as effects on emission levels at refineries in the Gulf Coast. In addition, we are concerned about levels of GHG emissions associated with the proposed Project, and whether appropriate mitigation measures to reduce these emissions are being considered. Moreover, the SDEIS does not contain sufficient information to fully assess the environmental impacts of the proposed Project, including potential impacts to groundwater resources and communities that could be affected by potential increases in refinery emissions.

We look forward to continuing to work with you to strengthen the environmental analysis of this project and to provide any assistance you may need to prepare the Final EIS. In addition, we will be carefully reviewing the Final EIS to determine if it fully reflects our agreements and that measures to mitigate adverse environmental impacts are fully evaluated. We look forward as well to working with you as you consider the determination as to whether approving the proposed project would be in the national interest under the provisions of Executive Order 13337.

Please feel free to contact me at (202) 564-2400, or have your staff contact Susan Bromm, Director, Office of Federal Activities, at (202) 564-5400, if you have any questions or would like to discuss our comments.

Sincerely,



Cynthia Giles

Enclosure

Summary of Rating Definitions and Follow-up Action

Environmental Impact of the Action

LO--Lack of Objections

The EPA review has not identified any potential environmental impacts requiring substantive changes to the proposal. The review may have disclosed opportunities for application of mitigation measures that could be accomplished with no more than minor changes to the proposal.

EC--Environmental Concerns

The EPA review has identified environmental impacts that should be avoided in order to fully protect the environment. Corrective measures may require changes to the preferred alternative or application of mitigation measures that can reduce the environmental impact. EPA would like to work with the lead agency to reduce these impacts.

EO--Environmental Objections

The EPA review has identified significant environmental impacts that must be avoided in order to provide adequate protection for the environment. Corrective measures may require substantial changes to the preferred alternative or consideration of some other project alternative (including the no action alternative or a new alternative). EPA intends to work with the lead agency to reduce these impacts.

EU--Environmentally Unsatisfactory

The EPA review has identified adverse environmental impacts that are of sufficient magnitude that they are unsatisfactory from the standpoint of public health or welfare or environmental quality. EPA intends to work with the lead agency to reduce these impacts. If the potentially unsatisfactory impacts are not corrected at the final EIS stage, this proposal will be recommended for referral to the CEQ.

Adequacy of the Impact Statement

Category 1--Adequate

EPA believes the draft EIS adequately sets forth the environmental impact(s) of the preferred alternative and those of the alternatives reasonably available to the project or action. No further analysis or data collection is necessary, but the reviewer may suggest the addition of clarifying language or information.

Category 2--Insufficient Information

The draft EIS does not contain sufficient information for EPA to fully assess environmental impacts that should be avoided in order to fully protect the environment, or the EPA reviewer has identified new reasonably available alternatives that are within the spectrum of alternatives analyzed in the draft EIS, which could reduce the environmental impacts of the action. The identified additional information, data, analyses, or discussion should be included in the final EIS.

Category 3--Inadequate

EPA does not believe that the draft EIS adequately assesses potentially significant environmental impacts of the action, or the EPA reviewer has identified new, reasonably available alternatives that are outside of the spectrum of alternatives analyzed in the draft EIS, which should be analyzed in order to reduce the potentially significant environmental impacts. EPA believes that the identified additional information, data, analyses, or discussions are of such a magnitude that they should have full public review at a draft stage. EPA does not believe that the draft EIS is adequate for the purposes of the NEPA and/or Section 309 review, and thus should be formally revised and made available for public comment in a supplemental or revised draft EIS. On the basis of the potential significant impacts involved, this proposal could be a candidate for referral to the CEQ.

Exhibit 12



In Reply Refer To:

United States Department of the Interior

BUREAU OF LAND MANAGEMENT

Miles City Field Office

111 Garryowen Road

Miles City, Montana 59301-7000

www.blm.gov/mt



October 2014 Comp Sale
3160 (MTC023)

May 19, 2014

Dear Reader:

The Bureau of Land Management (BLM) Miles City Field Office has prepared an environmental assessment (EA) to analyze the potential effects from offering 18 nominated lease parcels for competitive oil and gas leasing in a sale tentatively scheduled to occur on October 21, 2014.

The EA with an unsigned Finding of No Significant Impact (FONSI) is available for a 30-day public comment period. Written comments must be postmarked by June 18, 2014, to be considered. Comments may be submitted using one of the following methods:

Email: BLM_MT_Miles_CityFO_Lease_EA@blm.gov

Mail: Miles City Field Office
Attn: Jon David
111 Garryowen Road
Miles City, Montana 59301-7000

Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment – including your personal identifying information – will be available for public review. If you wish to withhold personal identifying information from public review or disclosure under the Freedom of Information Act (FOIA), you must clearly state, in the first line of your written comment, “CONFIDENTIALITY REQUESTED.” While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so. All submissions from organizations, from businesses, and from individuals identifying themselves as representatives of organizations or businesses, will be available for public review.

Upon review and consideration of public comments, the EA will be updated as needed. Based on our analysis, parcels recommended for leasing in our assessment would be included as part of a competitive oil and gas lease sale tentatively scheduled to occur on October 21, 2014.

Prior to issuance of any leases, the Decision Record and FONSI will be finalized and posted for public review on our BLM website. Please refer to the Montana/Dakotas BLM website at

<http://blm.gov/qtld>. Current and updated information about our EAs, Lease Sale Notices, and corresponding information pertaining to this sale can be found at the link referenced above.

If you have any questions or would like more information about lease sale notices or the issuance of the EA, Decision Record and FONSI, please contact me at 406-233-2837.

Sincerely,

A handwritten signature in black ink, appearing to read "Todd D. Yeager", with a stylized flourish at the end.

Todd D. Yeager
Field Manager

United States Department of the Interior
Bureau of Land Management

Environmental Assessment DOI-BLM-MT-C020-2014-0091-EA
May 19, 2014

Project Title: Oil and Gas Lease Parcel, October 21, 2014 Sale

Location: Miles City Field Office (see Appendix A for list of lease parcels by number and legal description and Maps 1-6)



Miles City Oil and Gas Lease Sale EA
DOI-BLM-MT-C020-2014-0091-EA

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Figure B – Northeastern Montana spring temperatures (March-May, 1895-2013). (Source: National Climatic Data Center (NCDC) website – <http://www.ncdc.noaa.gov/cag/>)

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Miles City Field Office Oil and Gas Lease Sale Parcel Reviews

DOI-BLM-MT-C020-2014-0091-EA

1.0 PURPOSE AND NEED

1.1 Introduction

It is the policy of the Bureau of Land Management (BLM) to make mineral resources available for use and to encourage development of mineral resources to meet national, regional, and local needs. This policy is based on various laws, including the Mineral Leasing Act of 1920 and the Federal Land Policy and Management Act of 1976. The Federal Onshore Oil and Gas Leasing Reform Act of 1987 Sec. 5102(a)(b)(1)(A) directs the BLM to conduct quarterly oil and gas lease sales in each state whenever eligible lands are available for leasing. The Montana State Office conducts mineral estate lease auctions for lands managed by the Federal Government, whether the surface is managed by the Department of the Interior (BLM or Bureau of Reclamation), United States Forest Service, or other departments and agencies. In some cases the BLM holds subsurface mineral rights on split estate lands where the surface estate is owned by another party, other than the Federal Government. Federal mineral leases can be sold on such lands as well. The Montana State Office has historically conducted five lease sales per year.

Members of the public file Expressions of Interest (EOI) to nominate parcels for leasing by the BLM. From these EOIs, the Montana State Office provides draft parcel lists to the appropriate field offices for review. The BLM field offices then review legal descriptions of nominated parcels to determine: if they are in areas open to leasing; if new information has come to light which might change previous analyses conducted during the land use planning process; if there are special resource conditions of which potential bidders should be made aware; and which stipulations should be identified and included as part of a lease. Ultimately, all of the lands in proposed lease sales are nominated by private individuals, companies, or the BLM, and therefore represent areas of high interest.

This environmental assessment (EA) has been prepared to disclose and analyze the potential environmental consequences from leasing all 18 nominated lease parcels encompassing a total of 7,945.28 surveyed Federal mineral acres located in the Miles City Field Office (MCFO), to be included as part of a competitive oil and gas lease sale tentatively scheduled to occur in October 21, 2014.

The analysis area includes the 18 nominated parcels in Richland, Roosevelt, McCone, Prairie, and Powder River counties (Map 1).

1.2 Purpose and Need for the Proposed Action

The purpose of offering parcels for competitive oil and gas leasing is to provide opportunities for private individuals or companies to explore for and develop Federal oil and gas resources in Richland, Roosevelt, McCone, Prairie, and Powder River counties after receipt of necessary approvals and to sell the oil and gas in public markets.

This action is needed to help meet the energy needs of the people of the United States. By conducting lease sales, the BLM provides for the potential increase of energy reserves for the U.S., a steady source of income, and at the same time meets the requirement identified in the Energy Policy Act, Sec. 362(2), Federal Oil and Gas Leasing Reform Act of 1987, and the Mineral Leasing Act of 1920, Sec. 17. Oil and gas companies filed Expressions of Interest (EOI) to nominate parcels for leasing by the BLM Montana. The BLM needs to respond to the EOIs by determining whether or not to recommend these lease parcels for competitive oil and gas lease sale and, if so, with any stipulations attached.

The decision to be made is whether to sell oil and gas leases on the lease parcels identified, and, if so, identify stipulations that would be included with specific lease parcels at the time of lease sale.

1.3 Conformance with Land Use Plan(s)

This EA is tiered to the information and analysis and conforms to the decisions contained in the Big Dry Resource Management Plan (RMP/EIS) of April 1996 and the Powder River RMP/EIS of March 1985, as amended (1994 Oil and Gas RMP/EIS Amendment, 2003 Final Statewide Oil and Gas Environmental Impact Statement and proposed Amendment of the Powder River and Billings RMPs, and the 2008 Final Supplement to the Montana Statewide Oil and Gas Environmental Impact Statement and Proposed Amendment of the Powder River and Billings RMPs). The Big Dry and Powder River RMPs are the governing land use plans for the MCFO. The lease parcels to potentially be offered for sale are within areas determined to be open to oil and gas leasing in the Big Dry and Powder River RMPs. An electronic copy of the Big Dry RMP/EIS and the Powder River RMP/EIS, as amended, can be located via the internet on the BLM home page, www.blm.gov/mt. On the home page, locate the heading titled “Montana/Dakotas,” then select “What We Do”, then click on the “Planning” link.

A more complete description of activities and impacts, related to oil and gas leasing, development, production, etc. can be found at pages 111 to 156 of the Big Dry RMP and pages 55 to 77 of the 1994 Oil and Gas Amendment of the Powder River RMP (for leasing decisions), and pages 4-1 to 4-310 of the 2008 Final Supplement to the Montana Statewide Oil and Gas Environmental Impact Statement and Proposed Amendment of the Powder River and Billings RMPs (for development, production, etc).

Analysis of the 18 parcels is documented in this EA, and was conducted by MCFO resource specialists who relied on professional knowledge of the areas involved, review of current databases, file information, and some site visits to ensure that appropriate stipulations were recommended for a specific parcel. Analysis may have also identified the need to defer entire or partial parcels from leasing pending further environmental review.

At the time of this review it is unknown whether a particular parcel will be sold and a lease issued. It is unknown when, where, or if future well sites, roads, and facilities might be proposed. Assessment of potential activities and impacts was based on potential well densities discerned from the Reasonably Foreseeable Development (RFD) Scenario developed for this environmental assessment (Appendix C), which is based on information contained in the MCFO RFD developed in 2005 and revised in 2012; it is an unpublished report that is available by

contacting the MCFO. The RFD contains projections of the number of possible oil and gas wells that could be drilled and produced in the MCFO area and used to analyze projected wells for the 18 nominated lease parcels. Detailed site-specific analysis and mitigation of activities associated with any particular lease would occur when a lease holder submits an application for permit to drill (APD). A more complete description of mitigation, BMPs, and conditions of approval related to oil and gas lease activities can be found at pages 302-326 of the Big Dry RMP, pages 130-137 of the 1994 Oil and Gas Amendment of the Powder River RMP, pages 3-6 of the 2008 Record of Decision for the Final Supplement to the Montana Statewide Oil and Gas Environmental Impact Statement and Proposed Amendment of the Powder River and Billings RMPs, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development-The Gold Book, and online at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html. Offering the parcels for sale and issuing leases would not be in conflict with any local, county, or state laws or plans.

1.4 Public Scoping and Identification of Issues

Public scoping for this project was conducted through a 15-day scoping period advertised on the BLM Montana State Office website and posted on the MCFO website National Environmental Policy Act (NEPA) notification log. Scoping was initiated March 25, 2014.

The BLM coordinates with Montana Fish, Wildlife, and Parks (MFWP), and the United States Fish and Wildlife Service (USFWS) to manage wildlife habitat because BLM management decisions can affect wildlife populations which depend on the habitat. The BLM manages habitat on BLM lands, while MFWP is responsible for managing wildlife species populations. The USFWS also manages some wildlife populations but only those Federal trust species managed under mandates such as the Endangered Species Act, Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act. Managing wildlife is factored into project planning at multiple scales and is to be implemented early in the planning process.

Coordination with Montana Fish Wildlife and Parks (MFWP) was conducted for the 18 lease parcels being reviewed and in the completion of this EA in order to prepare the analysis, identify protective measures, and apply stipulations and lease notices associated with these parcels being analyzed. A letter was sent to the USFWS and MFWP during the 15-day scoping and 30-day public comment periods requesting comments on the 18 parcels being reviewed. Refer to Section 5.2 of this EA for a more complete summary of the scoping comments received from MFWP.

The BLM consults with Native Americans under various statutes, regulations, and executive orders, including the American Indian Religious Freedom Act, the National Historic Preservation Act, the Native American Graves Protection and Repatriation Act, the National Environmental Policy Act, and Executive Order 13175-Consultation and Coordination with Indian Tribal Governments. The BLM sent letters to tribes in Montana, North and South Dakota and Wyoming for the 15-day scoping period informing them of the potential for the 18 parcels to be leased and inviting them to submit issues and concerns BLM should consider in the environmental analysis. Letters were sent to the Tribal Presidents and the Tribal Historical Preservation Officer (THPO) or other cultural contacts for the Cheyenne River Sioux Tribe, Crow Tribe of Montana, Crow Creek Sioux Tribe, Eastern Shoshone Tribe, Ft. Peck Tribes, Lower Brule Sioux Tribe, the Mandan, Hidasta, and Arkira Nation, Northern Arapaho Nation,

Northern Cheyenne Tribe, Oglala Sioux Tribe, Rosebud Sioux Tribe of Indians, Standing Rock Sioux Tribe, and Turtle Mountain Band of Chippewa. In addition to scoping letters, THPOs also received file search results from the preliminary review of parcels conducted by BLM. The BLM sent a second letter with a copy of the EA to the tribes informing them about the 30 day public comment period for the EA and solicit any information BLM should consider before making a decision whether to offer any or all of the nominated parcels for sale.

Site specific resource concerns were identified by the BLM through the preliminary review process conducted prior to a 15-day public scoping period. Lease stipulations (as required by Title 43 Code of Federal Regulations 3131.3) were added as necessary to each parcel as identified by the BLM to address site specific resource concerns.

The BLM focuses its analysis on issues that are truly significant to the action in question, rather than amassing needless detail” (40 CFR 1500.1(b)). Issues have a relationship with the proposed action; are within the scope of analysis; and are amenable to scientific analysis.

The issues carried forward through analysis in this EA are associated with air resources, greenhouse gas emission and climate change, economic resources, socioeconomics, cultural resources, paleontological resources, water resources, recreation and visual resources, wildlife habitat, Special Status and Sensitive Species, vegetation , livestock grazing management, invasive, non-invasive species and noxious weeds,

The BLM considered other issues, listed below, but decided not to analyze those in further detail. The aspects of the existing environment that the BLM determined to not be present or not potentially impacted by this project include: coal, locatable minerals, salable minerals, lands with wilderness characteristics, cave and karst resources, wild and scenic rivers; wilderness study areas. Thus, the EA contains no further discussion of these issues.

2.0 DESCRIPTION OF ALTERNATIVES, INCLUDING PROPOSED ACTION

2.1 Alternative A - No Action

For EAs on externally initiated Proposed Actions, the No Action Alternative generally means that the Proposed Action would not take place. In the case of a lease sale, this would mean that all expressions of interest to lease (parcel nominations) would be denied or rejected.

The No Action Alternative would exclude all 18 lease parcels, covering 7,945.28 surveyed Federal mineral acres (3,637.97 surveyed BLM administered surface and 4,307.31 surveyed private/State surface), from the competitive oil and gas lease sale (Maps 1-6). Surface management would remain the same and ongoing oil and gas development would continue on surrounding Federal, private, and State leases.

2.2 Alternative B – Proposed Action

The Proposed Action Alternative would be to offer 18 lease parcels of Federal minerals for oil and gas leasing, covering 7,945.28 surveyed Federal mineral acres (3,637.97 surveyed BLM administered surface and 4,307.31 surveyed private surface), in conformance with the existing

land use planning decisions. Parcel number, size, and detailed locations and associated stipulations are listed in Appendix A. Maps 1-6 indicate the detailed location of each parcel.

2.3 Alternative C -BLM Preferred

Under the BLM Preferred Alternative, 2 whole and 5 partial parcels of the 18 lease parcels, 1,396.87 surveyed Federal mineral acres (680 surveyed BLM administered surface and 716.87 surveyed private surface) would be offered with RMP lease stipulations and/or lease notices as necessary (Appendix A) for competitive oil and gas lease sale and lease issuance.

A total of 11 lease parcels in whole and 5 partial lease parcels, encompassing 6,549.15 surveyed Federal mineral acres (2,958.73 surveyed BLM administered surface and 3,590.42 private surveyed surface), are recommended for deferral. These lease parcels contain sage grouse, big game winter range, badlands rock outcrop, and sensitive soil protection areas being analyzed in the current MCFO RMP effort; therefore, 11 whole lease parcels and 5 partial lease parcels would be deferred at this time pending further review and analysis. This would provide for consideration of alternatives in the current MCFO RMP planning.

2.4 Additional Considerations for Alternatives B and C

For the split-estate lease parcels, the BLM provided courtesy notification to private landowners that the Federal oil and gas estate under their surface would be included in this lease sale. In the event of activity on such split estate lease parcels, the lessee and/or operator would be responsible for adhering to BLM requirements as well as reaching an agreement with the private surface landowners regarding access, surface disturbance, and reclamation.

The terms and conditions of the standard federal lease and federal regulations would apply to each parcel offered for sale in each of the two Alternatives. Stipulations shown in Appendix A would be included with identified parcels offered for sale. Standard operating procedures for oil and gas operations on federal leases include measures to protect the environment and resources such as groundwater, air, wildlife, historical and prehistorical concerns, and others as mentioned in the Big Dry and Powder River RMPs at pages 9 to 40 and 302 to 330 of the Minerals Appendix (Big Dry) and 2-1 to 2-28 and the Minerals Appendix Min-36 to Min-42 (2008 Final Supplement to the Montana Statewide Oil and Gas EIS and Proposed Amendment of the Powder River and Billings RMPs). Conditions of Approval (COAs) would be attached to permits issued to explore and develop the parcels to address site-specific concerns or new information. Standard operating procedures, best management practices (BMPs), COAs, and lease stipulations can change over time to meet RMP objectives, resource needs or land use compatibility.

Federal oil and gas leases would be issued for a 10-year period and would remain valid for as long thereafter as oil or gas is produced in paying quantities, required payments are made and lease operations are conducted in compliance with regulations and approved permits. If a lessee fails to produce oil and gas by the end of the initial 10 year period, does not make annual rental payments, or does not comply with the terms and conditions of the lease, the BLM would terminate the lease. The lessee can relinquish the lease. The oil and gas resources could be offered for sale at a future lease sale.

Drilling of wells on a lease would not be permitted until the lessee or operator secures approval of a drilling permit and a surface use plan as specified in 43 CFR 3162.

3.0 AFFECTED ENVIRONMENT

3.1 Introduction

This chapter describes the existing environment (i.e., the physical, biological, social, and economic values and resources) within the analysis area, which includes the 18 nominated parcels in Richland, Roosevelt, McCone, Prairie, and Powder River counties (Map 1), that could be affected by implementation of the alternatives described in Chapter 2.

The existing environment is described by the different resources found throughout the counties listed above. Within each resource description, lease parcels containing the resource will be listed and analyzed further in Chapter 4. If the lease parcel does not contain the resource, then the lease parcel will be omitted from the description of that specific resource.

Unless otherwise stated, resource analysis in this chapter, and Chapter 4, will be described in approximate acres due to the scaling and precision parameters associated with the Geographic Information System (GIS), in addition to being referenced to a different land survey.

Most of the analysis area consists of open expanses characteristic of the Northern Great Plains. This area is largely comprised of herbaceous vegetation (e.g., grasses) with interspersed shrubs (e.g., sagebrush). Lands with greater moisture or slopes exhibit ponderosa pine, limber pine, limited Douglas fir, and juniper species. Some hardwood trees grow along riparian areas and are common along the Missouri River. The analysis area experiences extreme weather variations on a yearly basis due to its semiarid continental climate. Most of the public lands are scattered throughout the analysis area. The public lands are rich in natural resources, such as wildlife and livestock forage, minerals, cultural resources, paleontological resources, recreation opportunities, and watershed values.

3.2 Air Resources

Air resources include air quality, air quality related values (AQRVs), and climate change. As part of the planning and decision making process, BLM considers and analyzes the potential effects of BLM and BLM-authorized activities on air resources.

The Environmental Protection Agency (EPA) has the primary responsibility for regulating air quality, including seven criteria air pollutants subject to National Ambient Air Quality Standards (NAAQS). Pollutants regulated under NAAQS include carbon monoxide (CO), lead, nitrogen dioxide (NO₂), ozone, particulate matter with a diameter less than or equal to 10 microns (PM₁₀), particulate matter with a diameter less than or equal to 2.5 microns (PM_{2.5}), and sulfur dioxide (SO₂). Two additional pollutants, nitrogen oxides (NO_x) and volatile organic compounds (VOCs) are regulated because they form ozone in the atmosphere. Regulation of air quality is also delegated to some states. Air quality is determined by pollutant emissions and emission characteristics, atmospheric chemistry, dispersion meteorology, and terrain. AQRVs include effects on soil and water, such as sulfur and nitrogen deposition and lake acidification, and aesthetic effects, such as visibility.

Climate is the composite of generally prevailing weather conditions of a particular region throughout the year, averaged over a series of years. Climate change includes both historic and predicted climate shifts that are beyond normal weather variations.

3.2.1 Air Quality

The EPA air quality index (AQI) is an index used for reporting daily air quality (<http://www.epa.gov/oar/data/geosel.html>) to the public. The index tells how clean or polluted an area's air is and whether associated health effects might be a concern. The EPA calculates the AQI for five criteria air pollutants regulated by the Clean Air Act (CAA): ground-level ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide. For each of these pollutants, EPA has established NAAQS to protect public health. An AQI value of 100 generally corresponds to the primary NAAQS for the pollutant. The following terms help interpret the AQI information:

- **Good** – The AQI value is between 0 and 50. Air quality is considered satisfactory and air pollution poses little or no risk.
- **Moderate** – The AQI is between 51 and 100. Air quality is acceptable; however, for some pollutants there may be a moderate health concern for a very small number of people. For example, people who are unusually sensitive to ozone may experience respiratory symptoms.
- **Unhealthy for Sensitive Groups** – When AQI values are between 101 and 150, members of “sensitive groups” may experience health effects. These groups are likely to be affected at lower levels than the general public. For example, people with lung disease are at greater risk from exposure to ozone, while people with either lung disease or heart disease are at greater risk from exposure to particle pollution. The general public is not likely to be affected when the AQI is in this range.
- **Unhealthy** – The AQI is between 151 and 200. Everyone may begin to experience some adverse health effects, and members of the sensitive groups may experience more serious effects.
- **Very Unhealthy** – The AQI is between 201 and 300. This index level would trigger a health alert signifying that everyone may experience more serious health effects.

AQI data show that there is little risk to the general public from air quality in the analysis area (Table 1). Based on available 2010–2012 data for Richland County in the northern portion of the planning area, 88 percent of the days were rated “good” and the three-year median daily AQI was 35. In the southern portion of the planning area, 2010–2012 data for Powder River County indicated that 82 percent of the days were rated good and the three-year median daily AQI was 37.

Table 1. US EPA – Air Data Air Quality Index Report (2010–2012)

County ¹	# Days in Period	# Days Rated Good or No Data	Percent of Days Rated Good or No Data	# Days Rated Moderate	# Days Rated Unhealthy for Sensitive Groups	# Days Rated Unhealthy	# Days Rated Very Unhealthy
Powder River	1,092	898	82%	194	0	0	0
Richland	1,096	968	88%	128	0	0	0

¹The Powder River and Richland County monitors are located near Broadus and Sidney, respectively.
Source: EPA 2013b.

The area managed by the MCFO is in compliance with all NAAQS. Based on monitoring data available for 2010 through 2012, maximum concentrations as a percentage of the NAAQS are summarized in Table 2. Data are not provided for CO and lead which are not monitored within the analysis area.

Table 2. Monitored Concentrations Representative of the Study Area ^a

Pollutant	Averaging Time	Applicable Standard ^b	Concentration ^d	
			Powder River County	Richland County
NO ₂	1 hour	100 ppb	16 ppb (16%)	9 ppb (9%)
O ₃	8 hour	0.075 ppm	0.055 ppm (73%)	0.057 ppm (76%)
PM ₁₀	24 hour	150 µg/m ³	100 µg/m ³ (67%)	100 µg/m ³ (67%)
PM _{2.5}	24 hour	35 µg/m ³	16 µg/m ³ (46%)	15 µg/m ³ (43%)
	Annual	12 µg/m ³	6 µg/m ³ (51%)	7 µg/m ³ (55%)
SO ₂	1 hour	75 ppb	N/A	5 ppb (7%)
	24 hour	140 ppb	N/A	1 ppb (21%)

^a Representative concentrations are based on data from the Sidney monitoring station in Richland County and the Broadus monitor in Powder River County.

^b Most restrictive national or State standard.

^c Monitored concentrations are the 2nd highest for 24-hour PM₁₀ and 24-hour SO₂; three-year average of the annual 4th highest daily maximum for 8-hour O₃; three-year average of the 98th percentile for 24-hour PM_{2.5} and 1-hour NO₂; and three-year arithmetic mean for annual PM_{2.5}.

^d Values in parentheses are monitored concentrations as a percentage of the most restrictive applicable standard.

Source: EPA 2013b.

Although ozone concentrations above the NAAQS have been monitored in some rural areas in other states with oil and gas activity, moderate ozone concentrations have been monitored in Montana oil and gas areas. Based on 2010-2012 data from monitors located near Sidney and Broadus, Montana, ozone concentrations are approximately 75 percent of the ozone NAAQS (MDEQ 2013).

Hazardous air pollutants (HAPs) would also be emitted from oil and gas operations, including well drilling, well completion, and gas and oil production. Recent air quality modeling performed for the MCFO indicates that concentrations of benzene, ethylbenzene, formaldehyde,

n-hexane, toluene, and xylene would be less than 14 percent of applicable health-based standards and that the additional risk of cancer would be less than 0.18 in one million (BLM 2013).

Air resources also include visibility, which can be degraded by regional haze due in part to sulfur, nitrogen, and particulate emissions. Based on trends identified during 2005-2009, visibility has degraded slightly at the Medicine Lake National Wildlife Refuge IMPROVE monitor in Sheridan County on the haziest days (20 percent worse days). On the 20 percent best (clearest) days, visibility at this monitor has been improving, as shown by decreasing haze in Figure A.

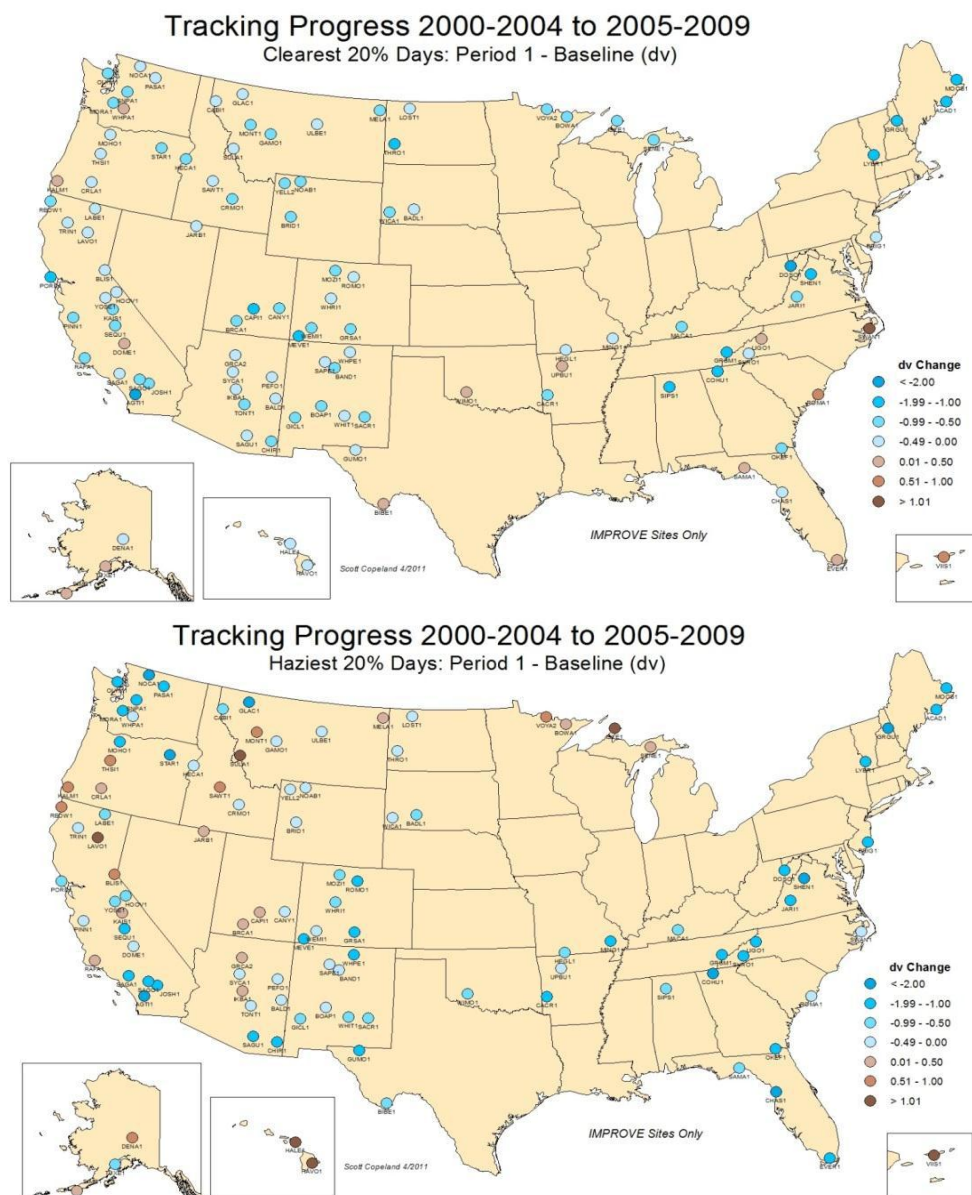


Figure A. Trends in haze index (deciview) on haziest and clearest days, 2005-2009. Source: IMPROVE 2011.

3.2.2 Climate Change

Climate change is defined by the Intergovernmental Panel on Climate Change (IPCC) as “a change in the state of the climate that can be identified (e.g., by using statistical tests) by changes in the mean and/or the variability of its properties, and persists for an extended period, typically decades or longer. Climate change may be due to natural internal processes or external forcings such as modulations of the solar cycles, volcanic eruptions and persistent anthropogenic changes in the composition of the atmosphere or in land use.” (IPCC 2013). Climate change and climate science are discussed in detail in the climate change Supplementary Information Report for Montana, North Dakota, and South Dakota, Bureau of Land Management (Climate Change SIR 2010). This document is incorporated by reference into this EA.

The IPCC states: “Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.” (IPCC 2013). The global average surface temperature has increased approximately 1.5°F from 1880 to 2012 (IPCC 2013). Warming has occurred on land surfaces, oceans and other water bodies, and in the troposphere (lowest layer of earth’s atmosphere, up to 4-12 miles above the earth). Other indications of global climate change described by the IPCC (Climate Change SIR 2010) include:

- Rates of surface warming increased in the mid-1970s and the global land surface has been warming at about double the rate of ocean surface warming since then;
- Eleven of the last 12 years rank among the 12 warmest years on record since 1850;
- Lower-tropospheric temperatures have slightly greater warming rates than the earth’s surface from 1958-2005.

As discussed and summarized in the climate change SIR, earth has a natural greenhouse effect wherein naturally occurring gases such as water vapor, CO₂, methane, and N₂O absorb and retain heat. Without the natural greenhouse effect, earth would be approximately 60°F cooler (Climate Change SIR 2010). Current ongoing global climate change is caused, in part, by the atmospheric buildup of greenhouse gases (GHGs), which may persist for decades or even centuries. Each GHG has a global warming potential that accounts for the intensity of each GHG’s heat trapping effect and its longevity in the atmosphere (Climate Change SIR 2010). The buildup of GHGs such as CO₂, methane, N₂O, and halocarbons since the start of the industrial revolution has substantially increased atmospheric concentrations of these compounds compared to background levels. At such elevated concentrations, these compounds absorb more energy from the earth’s surface and re-emit a larger portion of the earth’s heat back to the earth rather than allowing the heat to escape into space than would be the case under more natural conditions of background GHG concentrations.

A number of activities contribute to the phenomenon of climate change, including emissions of GHGs (especially CO₂ and methane) from fossil fuel development, large wildfires, activities using combustion engines, changes to the natural carbon cycle, and changes to radiative forces and reflectivity (albedo). It is important to note that GHGs will have a sustained climatic impact over different temporal scales due to their differences in global warming potential (described above) and lifespans in the atmosphere. For example, CO₂ may last 50 to 200 years in the

atmosphere while methane has an average atmospheric life time of 12 years (Climate Change SIR 2010).

With regard to statewide GHG emissions, Montana ranks in the lowest decile when compared to all the states (http://assets.opencrs.com/rpts/RL34272_20071205.pdf, Ramseur 2007). The estimate of Montana's 2005 GHG emissions of 37 million metric tons (MMt) of gross consumption-based carbon dioxide equivalent (CO₂e) account for approximately 0.6 percent of the U.S. GHG emissions (CCS 2007).

Some information and projections of impacts beyond the project scale are becoming increasingly available. Chapter 3 of the climate change SIR describes impacts of climate change in detail at various scales, including the state scale when appropriate. The EPA identifies eastern Montana as part of the Great Plains region. The following summary characterizes potential changes identified by the EPA (EPA 2008) that are expected to occur at the regional scale, where the Proposed Action and its alternatives are to occur.

- The region is expected to experience warmer temperatures with less snowfall.
- Temperatures are expected to increase more in winter than in summer, more at night than in the day, and more in the mountains than at lower elevations.
- Earlier snowmelt means that peak stream flow would be earlier, weeks before the peak needs of ranchers, farmers, recreationalist, and others. In late summer, rivers, lakes, and reservoirs would be drier.
- More frequent, more severe, and possibly longer-lasting droughts are expected to occur.
- Crop and livestock production patterns could shift northward; less soil moisture due to increased evaporation may increase irrigation needs.
- Drier conditions would reduce the range and health of ponderosa and lodgepole pine forests, and increase the susceptibility to fire. Grasslands and rangelands could expand into previously forested areas.
- Ecosystems would be stressed and wildlife such as the mountain lion, black bear, long-nose sucker, marten, and bald eagle could be further stressed.

Other impacts could include:

- Increased particulate matter in the air as drier, less vegetated soils experience wind erosion.
- Shifts in vegetative communities which could threaten plant and wildlife species.
- Changes in the timing and quantity of snowmelt which could affect both aquatic species and agricultural needs.

Projected and documented broad-scale changes within ecosystems of the U.S. are summarized in the Climate Change SIR. Some key aspects include:

- Large-scale shifts have already occurred in the ranges of species and the timing of the seasons and animal migrations. These shifts are likely to continue (USGCRP 2009, as cited by Climate Change SIR 2010). Climate changes include warming temperatures throughout the year and the arrival of spring an average of 10 days to 2 weeks earlier through much of the U.S. compared to 20 years ago. Multiple bird species now migrate north earlier in the year.

- Fires, insect epidemics, disease pathogens, and invasive weed species have increased and these trends are likely to continue. Changes in timing of precipitation and earlier runoff would increase fire risks.
- Insect epidemics and the amount of damage that they may inflict have also been on the rise. The combination of higher temperatures and dry conditions have increases insect populations such as pine beetles, which have killed trees on millions of acres in western U.S. and Canada. Warmer winters allow beetles to survive the cold season, which would normally limit populations; while concurrently, drought weakens trees, making them more susceptible to mortality due to insect attack.

More specific to Montana, additional projected changes associated with climate change described in Section 3.0 of the Climate Change SIR (2010) include:

- Temperature increases in Montana are predicted to be between 3 to 5°F at the mid-21st century. As the mean temperature rises, more heat waves are predicted to occur.
- Precipitation increases in winter and spring in Montana may be up to 25 percent in some areas. Precipitation decreases of up to 20 percent may occur during summer, with potential increases or decreases in the fall.
- For most of Montana, annual median runoff is expected to decrease between 2 and 5 percent. Mountain snowpack is expected to decline, reducing water availability in localities supplied by meltwater.
- Wind power production potential is predicted to decline in Montana based on modeling focused on the Great Falls area.
- Water temperatures are expected to increase in lakes, reservoirs, rivers, and streams. Fish populations are expected to decline due to warmer temperatures, which could also lead to more fishing closures.
- Wildland fire risk is predicted to continue to increase due to climate change effects on temperature, precipitation, and wind. One study predicted an increase in median annual area burned by wildland fires in Montana based on a 1°C global average temperature increase to be 241 to 515 percent.

While long-range regional changes might occur within this analysis area, it is impossible to predict precisely when they could occur. The following example summarizing climate data for northeastern Montana (Montana Climate Division 6) illustrates this point. A potential regional effect of climate change is earlier snowmelt and associated runoff. This is directly related to spring-time temperatures. Over a 118-year record, overall warming is clearly evident with temperatures increasing 0.2°F per decade (Figure B). Similar temperature increases occurred in southeastern Montana (Montana Climate Division 7).

However, data from 1991-2005 indicate a cooling trend of -1.3 degrees per decade (Figure C) in the northern and southern portions of the MCFO. This example is not an anomaly, as several other 15-year windows can be selected to show either warming or cooling trends. Substantial year-to-year fluctuations in temperature are due to natural processes, such as the effects of El Niños, La Niñas, and the eruption of large volcanoes (Climate Change SIR 2010). Annual fluctuations illustrate the difficulty of predicting actual short-term regional changes or conditions which may be due to climate change during any specific time frame.

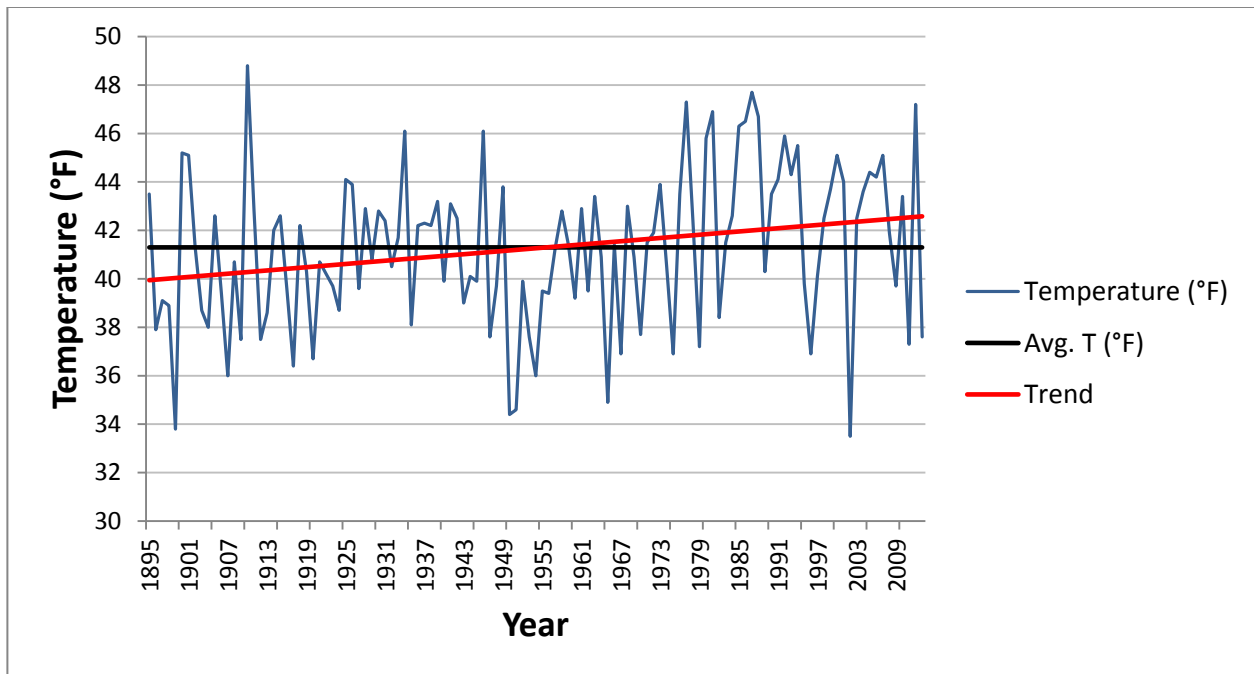


Figure B. Northeastern Montana spring temperatures (March-May, 1895-2013). (Source: National Climatic Data Center (NCDC) website – <http://www.ncdc.noaa.gov/cag/>)

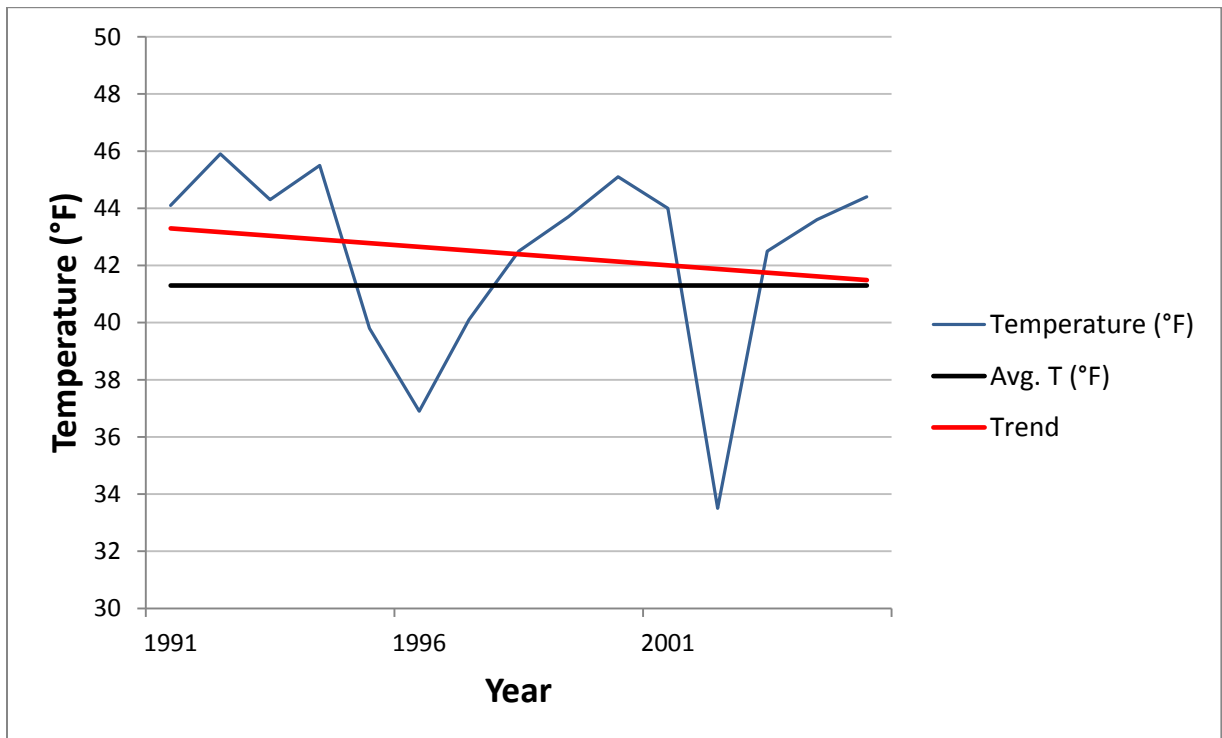


Figure C. Northeastern Montana spring temperatures (March-May, 1991-2005). (Source: National Climatic Data Center (NCDC) website – <http://www.ncdc.noaa.gov/cag/>)

From 1895–2013, annual precipitation decreased 0.06 inches per decade in the northern portion of the MCFO, while precipitation remained relatively constant in the southern portion. Throughout the MCFO, precipitation trends show increased during spring and fall seasons, while precipitation decreased during summer and winter.

3.3 Soil Resources

The soil-forming factors (climate, parent material, topography, biota, and age) are variable across the planning area, which results in soils with diverse physical, chemical, and biotic properties. Important properties of naturally functioning soil systems include biotic activity, diversity, and productivity; water capture, storage, and release; nutrient storage and cycling; contaminant filtration, buffering, degradation, immobilization, and detoxification; and biotic system habitat.

The lease parcels are located within 5 counties including Prairie, Roosevelt, Richland, Powder River, and McCone. The acreage of the lease parcels comprises less than 1 percent of each county. Soils considered prime farmlands if irrigated occur within lease parcels MTM 102757-WT, MTM 105431-HB, MTM 105431-HD, MTM 105431-HF, MTM 105431-HG, MTM 105431-HH, MTM 105431-HJ, MTM 105431-HK, MTM 105431-HL, and MTM 105431-HM. The following describes the common soil properties of lease parcels within each county:

Prairie County contains proposed parcels MTM 102757-WT and MTM 102757-WW. Parcel soils generally developed from the Fort Union Formation. Ecological sites within these parcels fall within MLRA 58A, 14-19 p. z. It is an area of old plateaus and terraces that have been eroded. Slopes generally are gently rolling to steep and wide belts of steeply sloping badlands. In some areas flat-topped, steep-sided buttes rise sharply above the general level of the plains. Most of soils in the parcels are rated high for soil restoration potential with a small percentage approximately 10 to 15 percent being rated low.

Roosevelt County contains proposed parcels MTM 105431-H9 and MTM 105431-JA. Parcel soils generally developed from the Fort Union Formation. Ecological Site Descriptions for these parcels are found with MLRA 53A, 14-18 p. z. Terrain in the Northern Dark Brown Glaciated Plains are gently undulating to rolling till plains in this area are interrupted by more strongly rolling and steep slopes adjacent to kettle holes, kames, moraines, and major stream valleys. All soils within these parcels are rated high for Soil Restoration Potential.

Richland County contains proposed parcels MTM 105431-HB, MTM 105431-H6 and MTM 105431-H8. Parcel soils generally developed from the Fox Hills, Hell Creek and Fort Union Formations. Ecological sites are typical of MLRA 53A, 14-18 p. z. or MLRA 58A, 14-18 p.z. Soils in these parcels are rated moderate to high for Soil Restoration Potential.

Powder River County contains proposed parcels MTM 105431-HC, MTM 105431-HD, MTM 105431-HE, MTM 105431-HF, MTM 105431-HG, MTM 105431-HH, MTM 105431-HK, MTM 105431-HL, MTM 105431-HM and MTM 105431-HJ. Parcel soils generally developed from the Fort Union Formation. Ecological sites within these parcels fall within MLRA 58B, 14-18 p. z. Slopes generally are gently rolling to steep and wide belts of steeply sloping badlands. In some areas flat-topped, steep-sided buttes rise sharply above the general level of the plains.

Most of the soils are rated moderate to high for Soil Restoration Potential with a smaller percentage being rated low.

McCone County contains proposed parcels MTM 105431-HA. Soils generally developed from Hell Creek and Fort Union Formations. Ecological Site Descriptions for these parcels are found with MLRA 53A, 14-18 p. z. Terrain in the Northern Dark Brown Glaciated Plains are gently undulating to rolling till plains in this area are interrupted by more strongly rolling and steep slopes adjacent to kettle holes, kames, moraines, and major stream valleys. Soils in this parcel are rated high for Soil Restoration Potential however some have not been rated.

3.4 Water Resources

3.4.1 Surface Hydrology

Surface water resources across the MCFO are present as lakes, reservoirs, rivers, streams, wetlands, and springs. Water resources are essential to the residents of eastern Montana to support agriculture, public water supplies, industry, and recreation. Water resources and riparian areas are crucial to the survival of many BLM-sensitive fish, reptiles, birds, and amphibians.

Perennial streams retain water year-round and have variable flow regimes. Intermittent streams flow during the part of the year when they receive sufficient water from springs, groundwater, or surface sources such as snowmelt or storm events. Ephemeral streams flow only in direct response to precipitation. Intermittent and ephemeral streams play an important role in the hydrologic function of the ecosystems within the lease parcels by transporting water, sediment, nutrients, and debris and providing connectivity within a watershed. They filter sediment, dissipate energy from snowmelt and storm water runoff, facilitate infiltration, and recharge groundwater (Levick et al. 2008). The pools of intermittent streams retain water in the summer months, supporting riparian vegetation and providing water resources for wildlife and livestock.

Stream morphology is influenced by a number of factors including: stream flow regime, geology, soils, vegetation type, climate, and land use history. Stream conditions reflect a number of historic and current impacts, ranging from agriculture to mining. Surficial geology is generally represented by Tertiary sandstones, siltstones, and shales, with some alluvium and glacial till which tends to form fine grain soils (loams to clays), that are highly erosive. Streambeds consist typically of sand and silt, with few bedrock channels. Stream morphology is highly influenced by the presence and type of riparian vegetation because streambeds and stream banks generally lack control features (e.g., rocks, cobbles, bedrock).

Approximately 90 acres of 100-year floodplains are present within 5 of the proposed lease parcels. These floodplains are generally associated with Crow Rock Creek and various unnamed intermittent streams. Floodplain function is essential to watershed function, water quality, soil development, stream morphology, and riparian-wetland community composition. Floodplains reduce flood peaks and velocities, thereby reducing erosion; enhancing nutrient cycling; reducing frequency and duration of low flows; and increasing infiltration, water storage, and aquifer recharge. Floodplains enhance water quality by facilitating sedimentation and filtering overland flow. Floodplains support high plant productivity, high biodiversity, and habitat for wildlife.

The lease parcels are located within 5 watersheds [HUC 8 (Hydrological Unit Code); subbasins]: Big Muddy Creek (HUC 10060006), Charlie-Little Muddy Creeks (HUC 10060005), Little Dry Creek (HUC 10040106), Little Powder River (HUC 10090208), and Redwater River (HUC 10060002). The acreage of the lease parcels comprises between less than 0.1 percent and 0.36 percent of each watershed (USGS 2009).

The Big Muddy watershed contains proposed parcels MTM 105431-H9 and JA; comprising less than 0.1 percent of the watershed. The lease parcels are located in Roosevelt County. The Charlie-Little Muddy Creeks watershed contains proposed parcels MTM 105431-HB, H6, and H8; comprising 0.15 percent of the watershed. The lease parcels are located in Richland County. The Little Dry Creek watershed contains proposed parcels MTM 102757-WT and WW; comprising 0.24 percent of the watershed. The parcels are located in Prairie County. The Little Powder River contains proposed parcels MTM 105431-HC, HD, HE, HF, HG, HH, HJ, HK, HL, and HM; comprising 0.36 percent of the watershed. The lease parcels are located in Powder River County. The Redwater River watershed contains proposed parcel MTM 105431-HA; comprising less than 0.1 percent of the watershed. The lease parcel is located in McCone County. Any beneficial use of produced water requires water rights to be issued by Montana Department of Natural Resources and Conservation (MDNRC) as established by law. Water used for oil well development may come from several different sources. It may be purchased from municipalities under certain conditions, appropriated from a surface water source under a new appropriation or by making changes to an existing water right, or by extracting groundwater from either a permitted or exempt well.

3.4.2 Groundwater

The quality and availability of groundwater varies greatly across the region. Residents in eastern Montana commonly get their ground water from aquifers consisting of unconsolidated, alluvial valley-fill materials, glacial outwash, or consolidated sedimentary rock formations and some coal beds.

Alluvial aquifers within the area generally consist of Quaternary alluvium and undifferentiated Quaternary/Tertiary sediments, which include sand and gravel deposits. Alluvial aquifers occur in terrace deposits and within the floodplains, and along the channels of larger streams, tributaries, and rivers, and are among the most productive sources of groundwater. They are typically 0-40 feet thick. The quality of groundwater from alluvial aquifers is generally good, but can be highly variable [approximately 100 mg/l to 2,800 mg/l TDS, specific conductance (SC) of 500 to 125,000 microsiemens/centimeter (uS/cm), and sodium adsorption ratio (SAR) of 5.0 to 10]. Wells completed in coarse sand and gravel alluvial aquifers can yield as much as 100 gallons per minute (gpm), although the average yield is 15 gpm. Alluvial deposits associated with abandoned river channels or detached terraces are topographically isolated and have limited saturation and yield as much as 20 gpm (Zelt et al. 1999).

Within the analysis area, the primary bedrock aquifers occur in sandstones and coal beds of the Tertiary Fort Union Formation (Cenozoic rocks) and the sandstones of the Cretaceous Hell Creek and Fox Hills formations (Mesozoic rocks). Wells within the Fort Union formation aquifers are typically 100 to 200 feet deep, but can be up to 1,500 feet in depth. These wells may produce as much as 40 gpm, but yields of 15 gpm are typical. Where aquifers are confined and

artesian conditions exist, wells in the Fort Union Formation will generally flow less than 10 gpm. Well depths within the Hells Creek and Fox Hills formation aquifers are highly variable, but typically range from 200 to 1,000 feet in depth. Groundwater yields from these aquifers may be as much as 200 gpm, but are generally less than 100 gpm. Artesian wells within these aquifers may flow as high as 20 gpm (Zelt et al. 1999). Groundwater yields from the deeper Paleozoic Madison formation aquifer can range from 20 to 6,000 gpm, or can be higher, in karst areas. The depth to the Madison formation aquifer in the planning area can exceed 6,000 feet. Due to the extreme depth of this aquifer, it is rarely accessed for water use. Water quality of this aquifer is highly variable and is dependent on depth, bedrock type, recharge rate, and other factors.

3.5 Vegetation Resources

The vegetation within the analysis area is characteristic of the Eastern Sedimentary Plains of Montana in the 10 to 14-inch precipitation zone and the Northern Dark Brown Glaciated Plains in the 10 to 14-inch precipitation zone, which lie within the Northern Great Plains. The Northern Great Plains is known for its diverse vegetation types, soil types, and topography. Vegetation is comprised of both tall and short grasses as well as both warm and cool season grasses. A variety of grass-like plants, forbs, shrubs and trees also add to the vegetation diversity of this rangeland type. Plant species diversity increases in woody draws and riparian/wetland zones.

Existing influences on local distribution of plant communities include soils, topography, surface disturbance, availability of water, management boundary fence lines, and soil salinity. Vegetation communities have been affected by human activities for over a century. Some of these activities include: infrastructure developments (roads, powerlines, pipelines, etc.), chemical applications, logging, livestock grazing, farming, and wildfire rehabilitation, prevention, manipulation, and suppression.

The BLM Standards of Rangeland Health (Standards) for BLM administered lands address upland health, riparian health, air quality, water quality, and habitat for native plants and animals. Meeting these Standards ensures healthy, productive, and diverse vegetative resources on public lands. The BLM's policy for implementing the Standards for Rangeland Health (43 CFR §4180.2) provides that all uses of public lands are to complement the established rangeland standards. Application of 43 CFR §4180.2 provides the mechanism to adjust livestock grazing to meet or progress towards meeting Standards for Rangeland Health. Effects of other uses such as oil and gas development or off-highway vehicle use are evaluated against the Standards to provide rationale directing management of these uses.

Six vegetation communities have been identified within the analysis area: native mixed grass prairie, sagebrush/mixed grasslands, ponderosa pine-mixed grassland, agricultural lands, improved or restored pastures, and riparian-wetlands.

There are numerous ecological sites identified within the analysis area, but the primary ones include the following; Sandy (Sy), Shallow (Sw), Silty (Si), Clayey (Cy) and Overflow (Ov). The total dry-weight production expected to be found on these sites during a normal growing season ranges from approximately 800 to 1,500 lbs. /acre.

The native mixed grassland community is dominated by perennial grasses. Perennial grasses can be both warm season and cool season grasses. These perennial grasses can also be both tall and short grasses. Some of the more common grasses include western wheatgrass (*Pascopyrum smithii*), needle-and-thread (*Hesperostipa comata*), green needlegrass (*Nassella viridula*), blue grama (*Bouteloua gracilis*), and prairie junegrass (*Koeleria macrantha*). Various forbs and shrubs are present but, occur as a minor species composition component throughout the community.

The sagebrush/ mixed grassland community occurs on lower valley slopes near drainages, especially where soils are deeper. This community can include a combination of silver sagebrush (*Artemisia cana*) and Wyoming big sagebrush (*Artemisia tridentata* ssp. *wyomingensis*). This setting is common throughout the analysis area. The sagebrush/grassland vegetation community has a perennial grass and forb understory, similar to the species found in a mixed native grassland community. The expected species composition on this community consists of 70-75 percent native grass species, 10-15 percent forbs, and 5-10 percent shrubs and half-shrubs.

The ponderosa pine-mixed grassland community generally occurs on moderate-to-steep upland slopes on shallow soils. Ponderosa pine is a minor component of the community canopy cover but is characteristic of the type. Fifty-two percent of canopy cover is provided by grasses, including bluebunch wheatgrass (*Pseudoroegneria spicata*), western wheatgrass, and prairie junegrass, with forbs comprising about 41 percent of cover and 50 percent of herbaceous production. This community type is very limited within the analysis area.

Improved or restored pastures consists of cultivated areas planted with introduced grasses (crested wheatgrass, smooth brome (*Bromus inermis*), intermediate wheatgrass (*Thinopyrum intermedium*), and alfalfa (*Medicago sativa*), specifically for the improved vegetation production for livestock consumption. This setting is limited in the analysis area.

The cultivated plant community is comprised of monocultures of crops which may include small grains, alfalfa, or other crops grown primarily as supplemental feed sources for livestock production operations. These areas have been completely disturbed from the native vegetation potentials. This setting is absent or very limited in the analysis area.

Wetland areas are defined as “areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient, and which, under normal circumstances, do support, a prevalence of vegetation adapted for life in saturated soil conditions.” Riparian areas are defined as “a form of wetland transition between permanently saturated wetlands and upland areas. These areas exhibit vegetation or physical characteristics reflective of permanent surface or subsurface water influence. Lands along, adjacent to, or contiguous with perennially and intermittently flowing rivers and streams, glacial potholes, and the shores of lakes and reservoirs with stable water levels are typical riparian areas. Excluded are such sites as ephemeral streams or washes that do not exhibit the presence of vegetation dependent upon free water in the soil” (Prichard et. al 1995).

Within the analysis area, riparian and wetland areas would be associated with lakes, reservoirs, potholes, springs, bogs, and wet meadows as well as ephemeral, intermittent, or perennial streams. Riparian and wetland areas are among the most productive and important ecosystems (Prichard et. al. 1995). Characteristically, riparian and wetland areas display a greater diversity of plant, fish, wildlife, and other animal species and vegetative structure than adjoining ecosystems. Adequate, healthy riparian and wetland vegetative buffers protect associated waterbodies from accelerated erosion and sedimentation and reduce or eliminate non-point source pollution from upland areas (MDEQ 2012). Healthy riparian and wetland systems filter and purify water as it moves through the riparian-wetland zone, reduce sediment loads and enhance soil stability, provide micro-climate moderation when contrasted to temperature extremes in adjacent areas, and contribute to groundwater recharge and base flow (Eubanks, 2004).

Riparian areas are considered to be some of the most biologically diverse habitats (FSEIS 2008). Some of the more common vegetative species that occur in riparian-wetland areas include prairie cordgrass (*Spartina pectinata*), switchgrass (*Panicum virgatum*), Canada wildrye (*Elymus canadensis*), American licorice (*Glycyrrhiza lepidota*), sedges (*Carex spp.*), rushes (*Juncus spp.*), willow (*Salix spp.*), chokecherry (*Prunus virginiana*), buffaloberry (*Shepherdia argentea*), cottonwood (*Populus spp.*), needleleaf sedge (*Carex duriuscula*), sandbar willow (*Salix exigua*), Nebraska sedge (*Carex nebrascensis*), softstem bulrush (*Schoenoplectus tabernaemontani*), beaked sedge (*Carex rostrata*), yellow willow (*Salix lutea*), common three-square (*Schoenoplectus pungens*), and green ash (*Fraxinus pennsylvanica*). Weedy and invasive species common to riparian areas are knapweed (*Centaurea stoebe*), leafy spurge (*Euphorbia esula*), Russian olive (*Elaeagnus augustifolia*), saltcedar (*Tamarisk ramosissima*), kochia (*Bassia prostrata*), thistle (*Cirsium arvense*), sweet clover (*Melilotus officinalis*), cocklebur (*Xanthium strumarium*), and gumweed (*Grindelia squarrosa*).

Wetlands provide watering points for wildlife and livestock and provide habitat diversity. Species include sedges (*Carex spp.*), rushes (*Juncus spp.*), bulrush (*Schoenoplectus spp.*), cattail (*Typha spp.*), wild rose (*Rosa spp.*), and snowberry (*Symphoricarpos spp.*). At higher elevations they are associated primarily with springs, seeps, and intermittent streams. Precipitation-dependent wetland sites fluctuate annually, in a range from dry to wet, in direct response to seasonal moisture, temperature, and wind.

From the Montana Natural Heritage Program (MTNHP) provisional mapping GIS data and the USFWS National Wetland Inventory (NWI) GIS data, 8 proposed lease parcels contain approximately 31 acres of delineated riparian or wetland areas (see Table 3). This list is not comprehensive because complete GIS data was not available for 1 of the lease parcels: MTM 105431-WW.

Table 3: MTNHP and USFWS Riparian and Wetland Areas by Lease Parcel^{1,2}

Riparian/Wetland Type	Classification	Acres
Freshwater Emergent Wetland	Palustrine, Emergent, Temporary Flooded	6.8
	Palustrine, Emergent, Temporary Flooded, Diked/Impounded	<0.1

Riparian/Wetland Type	Classification	Acres
	Palustrine, Emergent, Seasonally Flooded	6.4
	Palustrine, Emergent, Seasonally Flooded, Diked/Impounded	0.8
	Palustrine, Emergent, Semipermanently Flooded, Diked/Impounded	0.5
Freshwater Pond	Palustrine, Aquatic Bed, Semipermanently Flooded	5.8
	Palustrine, Aquatic Bed, Semipermanently Flooded, Diked/Impounded	3.3
	Palustrine, Unconsolidated Shore, Temporary Flooded, Diked/Impounded	0.2
	Palustrine, Unconsolidated Shore, Seasonally Flooded	<0.1
	Palustrine, Unconsolidated Shore, Seasonally Flooded, Diked/Impounded	2.6
Riparian	Riparian, Lotic, Forested	4.8

¹(USFWS 2009) ² This list is not comprehensive because complete GIS data was not available for lease parcels MTM 105431-WW.

Competition from invasive, non-native plants constitutes a potential threat to native plant species and wildlife habitat within the analysis area. Several invasive, non-native plant species are found in the analysis area including: crested wheatgrass (*Agropyron cristatum*), Japanese brome (*Bromus japonicas*), cheatgrass (*Bromus tectorum*), and foxtail barley (*Hordeum jubatum*). Crested wheatgrass occurs in areas as a result of being planted to increase forage production or to stabilize soils by reducing erosion. Cheatgrass, Japanese brome, and foxtail barley are all aggressive invasive species that out-compete desirable vegetation for water and soil nutrients.

Noxious weeds are invasive species and occur in scattered isolated populations throughout the analysis area. The most common species of noxious weeds are leafy spurge, Russian knapweed, spotted knapweed, field bindweed and Canada thistle. Noxious weed control is the responsibility of the land owner or land managing agency. Chemical and biological control methods are utilized, with chemical control being the more predominant.

3.6 Special Status Species

3.6.1 Special Status Plant Species

According to the MTNHP, there are no known threatened or endangered plant species located within the lease parcels. Ten plant species on the Montana Plant Species of Concern list have been identified as having suitable habitat in areas near these parcels (MTNHP, 2014). These species are listed in the Table 4 and have the potential to exist on the lease parcels. Three of these species are also identified as BLM “Sensitive” plants.

According to the MTNHP field guide, these plants are typically found in very specific habitats and do not occur predictably across the landscape. Following is a list of Montana’s species of concern that may have existing populations and/or suitable habitat on or near the lease parcels by county:

Table 4. MT Species of Concern and BLM Sensitive Plants in or near lease parcels

Plant Name	Common Name	County	Habitat Description
<i>Carex gravida</i>	Pregnant sedge	Richland	wetland/riparian
<i>Dalea enneandra</i>	Nine-anther prairie clover	Richland	grasslands (plains)
<i>Dalea villosa</i>	Silky prairie clover	Richland	sandy sites
<i>Dalea enneandra</i>	Nine-anther prairie clover	Richland	grasslands (plains)
<i>Dalea villosa</i>	Silky prairie clover	Richland	sandy sites
<i>Lobelia spicata</i> *	Pale-spiked Lobelia	Richland	Moist meadow
<i>Solidago ptarmicoides</i>	Prairie Goldenrod	Richland	Moist meadow
<i>Suckleya suckleya</i> *	<i>Suckleya suckleana</i>	Richland, Roosevelt	wetland/riparian
<i>Viburnum lentago</i> *	Nannyberry	Richland	Riparian forests
<i>Teucrium canadense</i>	American Germander	Roosevelt	Moist meadow
<i>Carex crawei</i> *	Crawe's Sedge	Prairie	wetland/riparian
<i>Astragalus barrii</i> *	Barr's Milkvetch	Powder River	Sparsely vegetated knobs and buttes
* BLM Sensitive			

3.6.2 Special Status Animal Species

Special status species (SSS), collectively, are USFWS Federally listed or proposed species, and the BLM sensitive species from the 2009 Montana/Dakota's sensitive species list. The BLM sensitive species also include both Federal candidate species and delisted species within 5 years of delisting.

3.6.2.1 Aquatic Wildlife

For aquatic wildlife in the analysis area there are 9 fish, 3 amphibians, and 2 aquatic reptile species that are special status or are sensitive species (Table 5). All of these species depend on perennial and intermittent streams or rivers with intact floodplains, wetlands, and riparian areas that have functional habitat. One fish species, the pallid sturgeon (*Scaphirhynchus albus*), was federally listed as endangered by the U.S. Fish and Wildlife Service in 1990. Threats to the pallid sturgeon are habitat modification, small population size, limited natural reproduction, hybridization, pollution and contaminants, and commercial harvest. The pallid sturgeon inhabits the large river systems of the analysis area. In the analysis area the Yellowstone River (from the MT/ND border upstream to near Forsyth, MT) and Missouri River (from the MT/ND border upstream to near Fort Benton) are considered pallid sturgeon habitat. Additionally, these large rivers are classified as having the highest concern for fish species (particularly ESA species and species of concern) habitat under the MFWP Crucial Area Planning System (CAPS 2010). The USFWS recently took further action by listing the shovelnose sturgeon (*Scaphirhynchus platorynchus*), which closely resembles the pallid sturgeon, as a threatened species where its range overlaps with the Pallid sturgeon (FWS 2010). In Table 6, endangered or sensitive aquatic wildlife species that occur within each of the lease parcels are listed.

Table 5. Aquatic sensitive or special status wildlife species in the analysis area.

Species	USFWS Status	BLM Sensitive	In Range	Suitable Habitat Present
Pallid Sturgeon	Endangered	Special Status	Yes	Yes
Blue Sucker	None	Sensitive	Yes	Yes
Northern Redbelly Dace *	None	None	Yes	Yes
Northern Redbelly X Finescale Dace	None	Sensitive	No	N/A
Paddlefish	None	Sensitive	Yes	Yes
Pearl Dace	None	Sensitive	Yes	Yes
Sauger	None	Sensitive	Yes	Yes
Iowa Darter *	None	None	Yes	Yes
Sicklefin Chub *	None	None	Yes	Yes
Sturgeon Chub	None	Sensitive	Yes	Yes
Snapping Turtle	None	Sensitive	Yes	Yes
Spiny Softshell	None	Sensitive	Yes	Yes
Plains Spadefoot	None	Sensitive	Yes	Yes
Great Plains Toad	None	Sensitive	Yes	Yes
Northern Leopard Frog	None	Sensitive	Yes	Yes

***Iowa darter, northern redbelly dace, and sicklefin chub are listed as species of concern by the Montana Fish, Wildlife, and Parks.**

Table 6. Endangered or sensitive aquatic wildlife species that occur in, or their ranges overlap with, the lease parcels.

Lease Parcel	Endangered or Sensitive Species
MTM 102757-WT	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 102757-WW	Blue sucker, Sauger, Northern redbelly dace, Northern leopard frog, Plains spadefoot, Great plains toad
MTM 105431-HA	Pallid sturgeon, Paddle fish, Blue sucker, Sturgeon chub, Sicklefin chub, Sauger, Iowa darter, Northern redbelly dace, Pearl dace, Northern leopard frog, Plains spadefoot, Great plains toad
MTM 105431-HB	Pallid sturgeon, Paddle fish, Blue sucker, Sturgeon chub, Sicklefin chub, Sauger, Iowa darter, Northern redbelly dace, Pearl dace, Northern leopard frog, Plains spadefoot, Great plains toad
MTM 105431-H6	Pallid sturgeon, Paddle fish, Blue sucker, Sturgeon chub, Sicklefin chub, Sauger, Iowa darter, Northern redbelly dace, Pearl dace, Northern leopard frog, Plains spadefoot, Great plains toad
MTM 105431-H8	Pallid sturgeon, Paddle fish, Blue sucker, Sturgeon chub, Sicklefin chub, Sauger, Iowa darter, Northern redbelly dace, Pearl dace, Northern leopard frog, Plains spadefoot, Great plains toad
MTM 105431-H9	Sauger, Iowa darter, Northern redbelly dace, Pearl dace, Northern leopard frog, Plains spadefoot, Great plains toad
MTM 105431-JA	Sauger, Iowa darter, Northern redbelly dace, Pearl dace, Northern leopard frog, Plains spadefoot, Great plains toad

Lease Parcel	Endangered or Sensitive Species
MTM 105431-HC	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM105431-HD	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HE	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HG	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HH	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HJ	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HF	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HK	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HL	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle
MTM 105431-HM	Blue sucker, Sauger, Northern leopard frog, Plains spadefoot, Great plains toad, Spiny softshell, Snapping turtle

Note: The sauger, northern leopard frog, plains spadefoot, and great plains toad may occur in all lease parcels.

3.6.2.2 Terrestrial Wildlife

Evaluating wildlife values at the landscape scale is key to understanding potential impacts of a project. Wildlife values, including terrestrial conservation species, species richness, game quality, and aquatic conservation connectivity, have been mapped at the landscape level for Montana by MFWP through their Crucial Areas Planning System (CAPS) 2010.

The lease parcels were reviewed in the CAPS GIS website as an overlay to potential aquatic, terrestrial, and habitat values. This course-scale landscape analysis of wildlife resources provides one tool for understanding the context of the wildlife values at a large scale. Fine-scaled tools, data, and resource information based on inventory and monitoring data, as well as local knowledge from BLM and MFWP employees, are used to further examine resource issues at the site-specific level for the specific resources contained in the lease parcels considered in this EA.

The analysis area covers a variety of habitat consistent with the Northern Great Plains. Lease parcels are located within short and mixed grass prairies, riparian habitats, cultivated lands, and others. See Section 3.5 for a detailed description of vegetation.

Some of these analysis areas provide habitat for species considered as BLM “special status species”. Table 6 presents the following: a list of species; whether the analysis area is within the current range of the species; and if so, whether suitable habitat is present within the lease parcels.

Table 7. Analysis area occurrence of BLM terrestrial sensitive species and USFWS threatened, endangered, candidate or proposed terrestrial species.

Species	USFWS Status	Special Status Species (SSS) and BLM Sensitive Species	In Current Range	Suitable Habitat Present
Mammals				
Gray Wolf*	None	Sensitive	No	Not applicable (N/A)
Grizzly Bear**	Threatened	Special Status Species (SSS)	No	N/A
Black-footed ferret	Endangered	SSS	No	No
Black-tailed prairie dog	None	Sensitive	Yes	No
Swift fox	None	Sensitive	Yes	Yes
Fisher	None	Sensitive	No	NA
Meadow Jumping Mouse	None	Sensitive	Yes	Yes
Great Basin Pocket Mouse	None	Sensitive	No	N/A
North American Wolverine	None	Sensitive	No	N/A
Pygmy rabbit	None	Sensitive	No	N/A
Long-legged Myotis	None	Sensitive	Yes	Yes
Long-eared Myotis	None	Sensitive	Yes	Yes
Fringed Myotis	None	Sensitive	No	N/A
Fringe-tailed Myotis	None	Sensitive	No	N/A
Pallid bat	None	Sensitive	No	N/A
Northern long-eared bat	Proposed Endangered	SSS	No	N/A
Townsend’s big-eared bat	None	Sensitive	Yes	Yes
White-tailed prairie dog	None	Sensitive	No	N/A
Birds				
Common loon	None	Sensitive	Yes	Yes

Species	USFWS Status	Special Status Species (SSS) and BLM Sensitive Species	In Current Range	Suitable Habitat Present
Franklin's gull	None	Sensitive	Yes	Yes
Interior least tern	Endangered	SSS	Yes	No
Black tern	None	Sensitive	Yes	Yes
White-faced ibis	None	Sensitive	Yes	Yes
Whooping crane	Endangered	SSS	Yes	Yes
Yellow rail	None	Sensitive	Yes	Yes
Piping plover	Threatened, with critical habitat	SSS	Yes	No
Mountain plover	None	Sensitive	Yes	No
Marbled godwit	Bird of Conservation Concern (BCC)	Sensitive	Yes	Yes
Long-billed curlew	BCC	Sensitive	Yes	Yes
Black-crowned night heron	None	Sensitive	Yes	Yes
Bobolink	None	Sensitive	Yes	Yes
Greater sage-grouse	Candidate	Sensitive	Yes	Yes
Burrowing owl	BCC	Sensitive	Yes	No
Great gray owl	None	Sensitive	No	NA
Three-toed woodpecker	None	Sensitive	No	NA
Trumpeter swan	None	Sensitive	yes	unlikely
Flammulated owl	None	Sensitive	No	NA
Bald eagle	BCC	Sensitive	Yes	Yes
Golden eagle	None	Sensitive	Yes	Yes
Ferruginous hawk	None	Sensitive	Yes	Yes
Swainson's hawk	None	Sensitive	Yes	Yes
Peregrine falcon	None	Sensitive	Yes	unlikely
Northern goshawk	None	Sensitive	No	NA
Sage thrasher	BCC	Sensitive	Yes	Yes
Sprague's pipit	Candidate	Sensitive	Yes	Yes
Sedge wren	None	Sensitive	Yes	Yes
Loggerhead shrike	BCC	Sensitive	Yes	Yes
Chestnut-collared longspur	BCC	Sensitive	Yes	Yes
McCown's longspur	BCC	Sensitive	Yes	Yes
Baird's sparrow	BCC	Sensitive	Yes	Yes
Brewer's sparrow	BCC	Sensitive	Yes	Yes
LeConte's sparrow	None	Sensitive	Yes	Yes
Nelson's Sharp-tailed sparrow	None	Sensitive	Yes	Yes
Horned grebe	BCC	None	Yes	Yes
American bittern	BCC	None	Yes	Yes
Prairie falcon	BCC	None	Yes	Yes
Upland sandpiper	BCC	None	Yes	Yes

Species	USFWS Status	Special Status Species (SSS) and BLM Sensitive Species	In Current Range	Suitable Habitat Present
Yellow-billed Cuckoo	BCC	SSS	Yes	possible
Short-eared owl	BCC	None	Yes	Yes
Lewis's woodpecker	BCC	None	No	NA
Red-headed woodpecker	BCC	Sensitive	Yes	Yes
Black-backed woodpecker	None	Sensitive	No	NA
Sage sparrow	BCC	Sensitive	Yes	unlikely
Grasshopper sparrow	BCC	None	Yes	Yes
Dickcissel	BCC	Sensitive	Yes	Yes
Blue-gray natchcatcher	None	Sensitive	No	N/A
Harlequin duck	None	Sensitive	No	N/A
Amphibians				
Great Plains toad	None	Sensitive	Yes	Yes
Northern leopard frog	None	Sensitive	Yes	Yes
Plains spadefoot toad	None	Sensitive	Yes	Yes
Boreal/Western Toad	None	Sensitive	No	N/A
Coeur d'Alene salamander	None	Sensitive	No	N/A
Reptiles				
Snapping turtle	None	Sensitive	Yes	Yes
Spiny softshell	None	Sensitive	Yes	Yes
Greater short-horned lizard	None	Sensitive	Yes	Yes
Milk snake	None	Sensitive	Yes	Yes
Western hog-nosed snake	None	Sensitive	Yes	Yes

Table 6 sources: Montana Bird Distribution Committee 2012; Werner, Maxell, Hendricks, and Flath. 2004; Foresman 2001; MTNHP, 2010; BLM, 2009; USDA – NRCS Plants Database, 2010

*Gray wolf has been delisted so has been moved to the sensitive list

**Grizzly bear has been delisted for the Greater Yellowstone ecosystem. In that area it is a Bureau sensitive species.

3.6.2.3 Threatened, Endangered, Candidate, and Proposed Species

Threatened, endangered, or candidate wildlife species may occupy habitat infrequently or seasonally within the analysis area. These species include the whooping crane, sage grouse, and Sprague's pipit.

The USFWS has identified a primary migration corridor for the Aransas-Wood Buffalo population of whooping cranes (http://ecos.fws.gov/docs/recovery_plan/070604_v4.pdf). Lease parcels H6, H8, H9, and JA are located within this primary migration corridor. Nesting by whooping cranes has not been documented in the analysis area; however, stopover observations have been documented in eastern MT.

Two species recently classified as USFWS candidate species occur within the analysis area. These are the Sprague's pipit and the greater sage grouse. Candidate species are those that warrant protection under the Endangered Species Act, but listing the candidate species is precluded by the need to address other listing actions of a higher priority. The USFWS will review the need for listing these species annually and will propose the species for protection when funding and workload for other listing actions allow.

On March 5, 2010, USFWS concluded sage grouse warrants protection under the Endangered Species Act. However, USFWS determined the listing of the species is precluded by the need to take action on higher priority species. Sage grouse was placed on the list of species that are candidates under the Endangered Species Act.

Sage grouse are a native prairie grouse species that are considered sagebrush obligates and depend on sagebrush for survival. Lease parcel WW is located within 0.25 miles of a sage grouse lek location. In addition, 3 other lease parcels are located within 2 miles of lek locations. These include parcels WT, HG, and HF. Instruction Memorandum (IM) No. 2012-043 (BLM, 2011) identified Preliminary Priority Habitat (PPH), and Preliminary General Habitat (PGH) polygons for sage grouse in the planning area. In addition, IM No. 2012-043 provides conservation policies and procedures for sage grouse management within these polygons. None of the parcels are proposed within the PPH polygon; however, parcels HD, HE, HG, HH, HJ, HF, HK, HL, and HM are located within the PGH polygon.

Sprague's pipit was recently classified as USFWS candidate species and occurs within the analysis area. Candidate species are those that warrant protection under the Endangered Species Act, but listing the candidate species is precluded by the need to address other listing actions of a higher priority. The USFWS will review the need for listing these species annually and will propose the species for protection when funding and workload for other listing actions allow. Sprague's pipits were found warranted, but precluded as a threatened or endangered species on September 15, 2010. Sprague's pipits are strongly tied to native prairie (land which has never been plowed) throughout their life cycle (Owens and Myres 1973, pp. 705, 708; Davis 2004, pp. 1138-1139; Dechant et al. 1998, pp. 1-2; Dieni et al. 2003, p. 31; McMaster et al. 2005, p. 219). They are rarely observed in cropland (Koper et al. 2009, p. 1987; Owens and Myres 1973, pp. 697, 707; Igl et al. 2008, pp. 280, 284) or land in the Conservation Reserve Program (a program whereby marginal farmland is planted primarily with grasses) (Higgins et al. 2002, pp. 46-47). Sprague's pipits will use nonnative planted grassland (Higgins et al. 2002, pp. 46-47; Dechant et al. 1998, p. 3; Dohms 2009, pp. 77-78, 88). Vegetation structure may be a better predictor of occurrence than vegetation composition (Davis 2004, pp. 1135, 1137). (Federal Register: September 15, 2010 (Volume 75, Number 178)) Montana Natural Heritage Tracker has documented observations of Sprague's pipits in Daniels, Sheridan, Roosevelt, McCone, Richland, Dawson, Prairie, Custer, and Fallon Counties within the Miles City Field Office. Therefore, the proposed lease parcels have been identified as providing potential suitable habitat for Sprague's pipits based on a Sprague's pipit suitable habitat model utilized by the Montana Department of Fish, Wildlife, and Parks (<http://apps.fwp.mt.gov/gis/maps/caps/>), and aerial photography (NAIP, 2011). Ground-truthing of the parcels has not occurred to document actual habitat use by Sprague pipits, or that suitable habitat exists within all of the parcels identified by

the model. However, it is likely that at least portions of these parcels provide suitable habitat for Sprague's pipits. These include parcels H8, H6, H9, JA, HB, HA, WW, and WT.

3.6.2.4 Other Sensitive Species

As noted in Table 6 above, up to 51 wildlife species considered as BLM "sensitive" have the potential to occur within the analysis area. These include 37 birds, 6 mammals, 3 amphibians, and 5 reptiles. This list is a combination of recent and historic observations. In some instances, historic observations are the only known record. If a species is noted as in range, it signifies that habitat within the field office would be considered within the documented range of occupation of habitat by a particular species during some phase of its life cycle. This might be only for a short time frame, during migrations, seasonally, or possibly year-round. Documentation of occupation of habitat by specific wildlife species is considered good across this area for some species, (e.g., sage grouse) and lacking for other species (small mammals, herptiles, raptors, etc.). However, the table documents the potential for wildlife species occurrence if at least one lease parcel is located within a particular sensitive species' known range of habitat occupation based on available science and research.

Various bird surveys throughout different years have been conducted across the MCFO, which may have included some of the lease parcel areas or at least similar habitats. Surveys have been conducted by the United States Geological Survey, University of Montana Avian Science Center, Rocky Mountain Bird Observatory, MTNHP, and other interested "birders." Migratory bird species diversity varies across the MCFO area. According to P.D. Skaar's Montana Bird Distribution, 6th edition (Lenard et al., 2003) species diversity ranges from less than 40 species per "latilong" (~3,200 square miles) to more than 200 across the analysis area.

The analysis area provides potential nesting, foraging, and migratory habitat for various species of raptors; however, recent surveys for raptor nests have not occurred. Two lease parcels, WT and HG, are located within 0.5 miles of one historic Ferruginous hawk nest. In addition, parcel WW is located within 0.5 miles of a Swainson's hawk nest. Other species that would be expected within the analysis area include red-tailed hawks, great-horned owls, northern harriers, bald and golden eagles, sharp-shinned hawks, and cooper's hawks. . Peregrine falcons are also known to migrate through eastern Montana.

3.7 Fish and Wildlife

3.7.1 Aquatic Wildlife

The aquatic resources in the analysis area include aquatic wildlife and habitat for fish, aquatic arthropods (insects and crustaceans), amphibians, reptiles, and bivalves. The habitat consists of rivers, streams, and reservoirs that provide habitat for a variety of aquatic wildlife and riparian communities (and their varying lifecycle stages).

Based on known fish presence (MFWP 2010), there are approximately 20 miles of fish-bearing streams within the analysis area, but due to ongoing inventory efforts, the discovery of more prairie streams that support native fish and other aquatic wildlife would occur. Additionally, prairie fish are constantly moving through a landscape that balances, at the local and landscape scale, between drying and flooding stages. Consequently, the ability to migrate during high flows is a crucial life history strategy.

Aquatic resource conditions of streams are strongly related to riparian vegetation, upland range conditions, land use impacts, and quality and quantity of in-stream water. Habitat conditions throughout the analysis area vary between and within water bodies; the upper and middle reaches of smaller streams may be intermittent, while the lower reaches may receive perennial flows, resulting in different habitat conditions and different aquatic communities within the same stream. Prairie fish are adapted to these cycles of drying and flooding and thrive in these intermittent pools, provided land-use impacts are not severe (Bramblett et al. 2005). However, prairie streams are highly sensitive to disturbance, and due to this factor many prairie stream ecosystems are already imperiled due to anthropogenic activities (Dodds et al. 2004).

Riparian vegetation is a critical component in maintaining aquatic wildlife habitat and is a source of organic nutrients and food items for the prairie stream ecosystem, provides in-stream habitat for fish, amphibians, reptiles, and invertebrates, adds structure to the banks, and reduces erosion; when riparian vegetation senesces and falls into the stream, it adds cover, habitat complexity, and moderates water temperatures. In some cases throughout the analysis area, riparian habitats have been degraded, and the results include increases in erosion and sedimentation, shallower and wider streams (which increases evaporation and thus decreases water quality and quantity), increases in temperature fluctuations, and critically low oxygen content levels; these effects collectively reduce or degrade available aquatic wildlife habitat.

Existing factors limiting or affecting aquatic resources in the analysis area include the lack of a normative flow regime primarily through extensive reservoir development; loss or degradation of riparian habitat; habitat fragmentation; livestock grazing damage; past and current oil and gas development; un-passable fish & aquatic wildlife culverts, oil skimmers, and other stream crossings; and excess siltation due to the various land use activities.

3.7.2 General Wildlife

A diversity of topography and vegetation types exists across the analysis area. This diversity provides habitat for many wildlife species in addition to those previously mentioned.

Current and historic land uses within or adjacent to the lease parcels include grazing, farming, hunting, energy development, and others. A few areas contain blocks of well-functioning habitats, while other areas are composed of small, fragmented patches of native habitat and cultivated lands. In some areas, existing anthropogenic disturbance at some frequency can be expected to reduce habitat suitability for some species of wildlife intolerant to human activities.

The analysis area supports a variety of game and nongame species. Limited wildlife species and habitat surveys have been conducted within a portion of the analysis area. Although the entire area has not been comprehensively surveyed for all wildlife resources, past surveys document what species occur, and provides insight into what other species can be expected to occur within existing habitat types.

Mule deer are the most abundant big game species and use the greatest variety of habitats, generally preferring sagebrush, grassland, and conifer types (BLM 1984). Habitat diversity appears to be a good indicator of intensity of deer use. In mule deer habitats, diversity of

vegetation usually followed topographic diversity; thus, rugged topography may be the ultimate factor influencing mule deer use of an area (Mackie et. al. 1998). Habitat such as riparian bottoms, agricultural areas, and forests are used as well, both yearlong or seasonally. Habitat to support mule deer exists within all of the lease parcels.

Winter range is often part of year-round habitat in eastern Montana. Winter ranges are typically in areas of rougher topography and are often dominated by shrub species that provide crucial browse during winter months. Rough topography also provides critical escape and thermal cover important for maintenance and survival. Of the 18 proposed lease parcels, 6 of those are located within mule deer winter range. These include parcels H8, H6, HB, HK, HL, and HM.

White-tailed deer are common in the analysis area. White-tailed deer prefer riparian drainage bottoms, hardwood draws, and conifer areas, but they will also use a variety of other habitats including farmlands. During the winter, white-tailed deer using forested areas prefer dense canopy classes, moist habitat types, uncut areas, and low snow depths. Suitable winter range is a key habitat factor for white-tailed deer, and winter concentration areas occur almost exclusively in riparian and wetland habitats and dense pine (Youmans and Swenson 1982). Although white-tailed deer move on and off winter range, as dictated by seasonal habitat requirements, the animals do not migrate for long distances (Hamlin 1978). One parcel, HM, is proposed for lease within delineated crucial white-tailed deer winter range.

Pronghorn antelope are widely distributed across the analysis area. They are generally associated with grasslands and shrublands, but they also seasonally use agricultural fields. Winter ranges for pronghorn antelope generally occur within sagebrush grasslands with at least greater densities of big sagebrush than the surrounding areas. Crucial winter ranges for pronghorn exist within parcels WW, WT, HC, HD, HE, HG, HH, HJ, and HF. The potential exists for other big game species to occupy the areas. Species include elk, moose, mountain lion, and black bear although presence would likely occur as individual's transition to preferred habitats elsewhere.

The potential for big game movements or migrations through eastern Montana are not fully understood. At a local level, it is reasonable to assume big game movements occur at least seasonally. Migration corridors have not been identified through any of the lease parcels.

Sharp-tailed grouse are the other native prairie grouse species in the analysis area. Sharp-tailed grouse generally prefer hardwood draws, riparian areas, and prairie grasslands intermixed with shrubs such as chokecherry and buffaloberry. Lease parcels H8 and WW are located within 0.25 miles of sharp-tailed grouse dancing grounds. In addition, portions or all of 10 lease parcels are located within 2 miles of sharp-tailed grouse leks, and most of these parcels would be expected to provide at least seasonal habitat for sharp-tailed grouse. These parcels include H8, H6, WW, WT, HC, HD, HE, HK, HL, and HM.

Wild turkeys, pheasants, and Hungarian partridge are all species that have been introduced to eastern Montana and would be expected to utilize available habitats within some of the parcels.

3.8 Cultural Resources

The BLM is responsible for identifying, protecting, managing, and enhancing cultural resources

located on public lands or those that may be affected by BLM management actions on non-Federal lands. Cultural resources include archaeological, historic, architectural properties, and traditional lifeway values important to Native Americans. Sites can vary with regard to their intrinsic value as well as their significance to scientific study; therefore, management practices employed are commensurate with their designation. Significant cultural resource values include; their use to gather scientific information on human culture, history, interpretive and educational value, values associated with important people and events of significance in history, and often aesthetic value, as in a prehistoric rock art panel or an historic landscape.

A generalized prehistory of eastern Montana can be categorized in a chronological framework, and time periods are distinguished on the basis of differences in material culture traits or artifacts and subsistence patterns: the PaleoIndian period (ca. 12,500 BP-7800 BP), Archaic period (ca. 7800 BP-1500 BP), Prehistoric period (ca. 1500 BP-200 BP), Protohistoric period (ca. 250 BP-100 BP), and Historic Periods (A.D. 1805-A.D. 1960) (Aaberg et al 2006).

Cultural sites are evaluated with reference to their eligibility for listing on the National Register of Historic Places (NRHP). Each site is considered on a case-by-case basis.

A recent Class I overview of cultural resources was prepared for the analysis area (Aaberg et al 2006). The cultural environment of the MCFO as of May 2005 contained 7,065 prehistoric and 2,869 historic archeological sites as well as 1,929 paleontological localities. Archeological properties (historic and prehistoric sites) occur in all counties encompassed by the field office. The five counties with nominated lease parcels contain 33.8 percent of all prehistoric and 29.9 percent of all historic resources within the MCFO. Each of the five counties contains the following percentages of resource site types within its boundaries: McCone 2.3 percent prehistoric, 4.2 percent historic, Powder River 23.2 percent prehistoric, 8.1 percent historic, Prairie 2.6 percent prehistoric, 5.2 percent historic, Richland 1.9 percent prehistoric, 6.1 percent historic and Roosevelt 3.7 percent prehistoric, 6.2 percent historic.

The overall archeological site density of the MCFO (historic and prehistoric) is estimated at one site per 93 acres (Aaberg et al 2006). Prehistoric sites are estimated to be distributed at one site per 130.8 acres (4.9 per square mile) and historic sites at one site per 322 acres (two per square mile) for all surveyed acres within the MCFO. Approximately 10% to 15% of all sites are found to be or have the potential to be eligible for listing in the National Register of Historic Places.

A review of the Montana State Historical Preservation Office (SHPO) Cultural Resource Information System (CRIS) and Cultural Resource Annotated Bibliography System (CRABS), as well as BLM Cultural Resource databases and GIS data, indicates one (1) lease parcel (MTM 105431-H9) contains recorded cultural sites within the lease parcel boundaries. Inventory data is not available for a majority of individual lease parcels; however some parcels have incomplete coverage of cultural resource inventory.

The one parcel with identified sites contains three sites, all of the same site type within the boundaries of the reviewed parcel. Each site is a stone circle site. None of the sites have been evaluated for eligibility for inclusion in the National Register of Historic Places and may be of interest to Native American concerns, See Section 3.9.

3.9 Native American Religious Concerns

The BLM's management of Native American Religious concerns is guided through its 8120 Manual: *Tribal Consultation Under Cultural Resources Authorities* and 8120 Handbook: *Guidelines for Conducting Tribal Consultation*. Further guidance for consideration of fluid minerals leasing is contained in BLM Washington Office Instruction Memorandum 2005-003: Cultural Resources, Tribal Consultation, and Fluid Mineral Leasing. The 2005 memo notes leasing is considered an undertaking as defined in the National Historic Preservation Act. Generally areas of concern to Native Americans are referred to as "Traditional Cultural Properties" (TCPs) which are defined as cultural properties eligible for the National Register of Historic Places because of its association with cultural practices or beliefs that (a) are rooted in that community's history and (b) are important in maintaining the continuing cultural identity of the community.

Areas of tribal concern in southeast Montana are listed in Appendices B-E of the Ethnographic Overview of Southeast Montana (Peterson and Deaver 2002). Based on input from various tribes, the 2002 Ethnographic Overview also identified 12 sensitive site types. These include battlefield and raiding sites, burials, cairns, communal kills, fasting beds (vision quests), homesteads, medicine lodges, rock art, settlements (campsites), stone rings, spirit homes, and environmental places (plant gathering areas, mineral and fossil collection areas).

The Crow Tribe's 2002 document noted rock art, fasting sites, siege sites, camp sites, mourning sites, final resting places (burials), buffalo jumps, and environmental areas, including animal habitats and natural areas of concern such as springs. The Northern Cheyenne Tribe in its 2002 document noted large ring sites (both in terms of ring diameters and ring numbers), isolated fasting beds, rock art sites, and large diameter fasting structure as having religious significance to the tribe.

One parcel (MTM 105431-H9) contains three stone circle sites (24RV141-24RV143). The sites are currently unevaluated for listing on the National Register of Historic Places. A review of 2009 aerial imagery shows the well was not drilled and the sites have not been impacted by fluid mineral development. Prior to surface any surface disturbance the sites require a reevaluation of National Register eligibility including tribal participation.

3.10 Paleontology

According to Section 6301 of the Paleontological Resource Protection Act of 2009 Omnibus Public Lands Bill, Subtitle D, SEC. 6301, paleontological resources are defined as "any fossilized remains, traces, or imprints of organisms, preserved in or on the earth's crust, that are of paleontological interest and that provide information about the history of life on earth" (Paleontological Resource Protection Act of 2009 Omnibus Lands Bill, Subtitle D, SEC. 6301-3612 (P.L. 59-209; 34 Stat. 225; 16 U.S.C. 431-433). All vertebrate fossils, be they fossilized remains, traces, or imprints of vertebrate organisms, are considered significant. Paleontological resources do not include archaeological and cultural resources.

The BLM utilizes the Potential Fossil Yield Classification (PFYC) as a planning tool for identifying areas with high potential to yield significant fossils. The system consists of numbers ranging from 1-5 (low to high) assigned to geological units, with 1 being low potential and 5

being high potential to have significant fossil resources. It should be pointed out that the potential to yield significant fossil resources is never 0. Rock units not typically fossiliferous can in fact contain fossils in unique circumstances.

The BLM classified geologic formations that have a high Potential Fossil Yield Classification (PFYC) of 3 or higher should be specifically reviewed for paleontological resources. The MCFO has the following classifications on the relevant geologic units:

Quaternary deposits	Class 2 and 3
Ft Union	Class 4
Hell Creek	Class 5

All or part of the 18 parcels include geologic units rated as PFYC 3-5 and should be evaluated for fossil resources before and potentially during ground-disturbing activities.

3.11 Visual Resources

BLM Visual Resource classifications are only applied to BLM surface acres, as such the affected environment for visual resources only consists of approximately 3,640 acres of BLM - administered surface in the analysis area (Table 7).

A Class II VRM area classification means that the character of the landscape has unique combinations of visual features such as land, vegetation, and water. The existing character of the landscape should be retained. Activities or modifications of the environment should not be evident or attract the attention of the casual observer. Changes caused by management activities must repeat the basic elements of form, line, color, and texture found in the predominant natural features of the characteristic landscape.

A Class III VRM area classification means the level of change to the character of the landscape should be moderate. Changes caused by management activities should not dominate the view of the casual observer and should not detract from the existing landscape features. Any changes made should repeat the basic elements found in the natural landscape such as form, line, color and texture.

A Class IV VRM area classification means that the characteristic landscape can provide for major modification of the landscape. The level of change in the basic landscape elements can be high. However, every attempt should be made to minimize the impact of these activities through careful location, minimal disturbance, and repeating the basic elements.

Table 8: VRM Classes for the analysis area by lease parcel

Leasing Areas	VRM Class II Acres	VRM Class III Acres	VRM Class IV Acres
<i>RICHLAND COUNTY</i>	<i>0 total acres</i>	<i>722 total acres</i>	<i>37 total acres</i>
MTM 105431-HB	0	600	0
MTM 105431-H6	0	122	0
MTM 105431-H8	0	0	37
<i>PRAIRIE COUNTY</i>	<i>0 total acres</i>	<i>961 total acres</i>	<i>958 total acres</i>
MTM 102757-WT	0	961	0
MTM 102757-WW	0	0	958

POWDER RIVER COUNTY	0 total acres	0 total acres	960 total acres
MTM 105431-HD	0	0	80
MTM 105431-HE	0	0	160
MTM 105431-HK	0	0	640
MTM 105431-HL	0	0	80

3.12 Forest and Woodland Resources

Evergreen forest habitat types occurring in the analysis area include ponderosa pine (*Pinus ponderosa*) and Rocky Mountain juniper (*Juniperus scopulorum*). Deciduous forest habitat types include Green ash (*Fraxinus pennsylvanica*)/Chokecherry (*Prunus virginiana*), and Great Plains Cottonwood (*Populus deltoids*)/Herbaceous Communities. The deciduous habitat types occur along streams, rivers, lakes springs, and ponds, occupying terraces, fans, and floodplain positions. The Green ash/Choke cherry habitat types occur in V-shaped ravines (also called woody draws), where sites may occasionally be flooded by storm runoff flows. Table 9, summarizes forest and woodland acres in the analysis area by forest type and individual parcel.

Table 9. Forestland Acreage and Forest Type by Lease Parcel

Lease Parcel	Evergreen Forest	Deciduous Forest	Mixed Forest	Total Acres
MTM 102757-WT				
MTM 102757-WW				
MTM 105431-H6		123		123
MTM 105431-H8				
MTM 105431-H9				
MTM 105431-HA				
MTM 105431-HB	66			66
MTM 105431-HC	1006	235	7	1248
MTM 105431-HD	591		57	648
MTM 105431-HE				
MTM 105431-HF			4	4
MTM 105431-HG				
MTM 105431-HH			5	5
MTM 105431-HJ		3	7	10
MTM 105431-HK				
MTM 105431-HL			4	4
MTM 105431-HM	8			8
MTM 105431-JA				
Total	1671	361	84	2116

Source: GAP Vegetation Cover Types

The deciduous forest habitats add to the overall diversity of the landscape. They also attract wildlife and livestock for thermal cover, nesting habitat, moisture, browse and, and hiding cover. Because of this, these woodlands are focal points for some of the livestock and wildlife management. The evergreen forests occur in a mosaic patters across the grasslands. These evergreen habitats commonly occur on moderate to steep slopes. Ponderosa pine species tolerates dry environments more successfully than other native conifer except Rocky Mountain juniper. Rocky Mountain juniper has an interesting ecological role in the northern Great Plans.

In some cases, it can be the dominant species present in the stand or can be the understory of Ponderosa pine stands and some deciduous stands.

3.13 Livestock Grazing

Nine of the parcels (MTM 105431-H8, MTM 105431-H6, MTM 105431-HB, MTM 105431-HD, MTM 105431-HE, MTM 105431-HK, MTM 105431-HL, MTM 102757-WW, and MTM 102757-WT) in whole or part have BLM surface ownership within currently permitted grazing allotments. These parcels occur in Richland, Prairie and Powder River counties and include portions of ten separate grazing allotments. Cattle are the only class of livestock authorized to graze these allotments. Of the ten allotments, seven of the grazing authorizations do not restrict the grazing season or number of livestock due to the small percentage of public land within the allotment. Three allotments are authorized under active use which has strict seasons and numbers and are typically made up of a higher percentage of public land. None of the allotments are under an Allotment Management Plan (AMP). These allotments contain range improvements such as fences and reservoirs that have access roads for livestock management purposes. The remainder of the lease parcels does not contain any BLM administered lands and are primarily lands with private surface ownership.

3.14 Recreation and Travel Management

The BLM only manages recreational opportunities and experiences on BLM-administered surface. The affected environment consists of approximately 3,640 acres of BLM-administered surface. Recreational activities enjoyed by the public on BLM lands within the analysis area include hunting, hiking, camping, fishing, photography, picnicking, and winter activities such as snowshoeing and snowmobiling. Benefits and experiences enjoyed by recreational users include opportunities for solitude, spending time with families, enhancing leisure time, improving sports skills, enjoying nature and enjoying physical exercise.

Out of the approximately 3,640 BLM-administered acres proposed for lease, less than 950 acres have legal public access. The types of public use on the 950 acres lease parcels can be characterized as casual dispersed recreational activities including hiking, hunting (including outfitters), camping, and wildlife viewing. The rest of the BLM-administered acres have no public easements or rights-of-way across private property for legal land access. The lack of public access limits use of the BLM parcels for recreational use by the general public.

3.15 Lands and Realty

The analysis area consists of 18 parcels that include 7,945.28 surveyed surface acres of which 3,637.97 surveyed acres are BLM administered surface and 4,307.31 surveyed acres are Non-Federal surface (private). Table 10 below categorizes the 18 parcels by surface ownership and county.

There are three lease parcels with authorized BLM Rights-of Way (ROWs) approved on BLM administered surface, MTM-102757-WT, MTM-105431-HB and MTM-105431-H8.

Table 10. Number of parcels, surface ownership, and acres by county.

County	Parcels	Owner-ship	Acres
MCCONE			
	1 parcel (MTM-105431-HA)	Non-Federal	40
	1 TOTAL		40
RICHLAND			
	3 partial parcels (MTM-105431-HB, MTM-105431-H6, MTM-105431-H8)	BLM	758.73
	3 partial parcels (MTM-105431-HB, MTM-105431-H6, MTM-105431-H8)	Non-Federal	430.48
	3 TOTAL		1189.21
ROOSEVELT			
	1 parcel (MTM-105431-H9)	Non-Federal	160.02
	1 parcel (MTM-105431-JA)	Non-Federal	39.94
	2 TOTAL		199.96
PRAIRIE			
	1 parcel (MTM-102757-WT)	BLM	961.22
	1 parcel (MTM-102757-WW)	BLM	958.02
	2 TOTAL		1,919.24
POWDER RIVER			
	1 parcel (MTM-105431-HC)	Non-Federal	640
	1 partial parcel (MTM-105431-HD)	Non-Federal	560
	1 partial parcel (MTM-105431-HD)	BLM	80
	1 parcel (MTM-105431-HE)	BLM	160
	1 parcel (MTM-105431-HG)	Non-Federal	160
	1 parcel (MTM-105431-HH)	Non-Federal	440
	1 parcel (MTM-105431-HJ)	Non-Federal	316.87
	1 parcel (MTM-105431-HF)	Non-Federal	640
	1 parcel (MTM-105431-HK)	BLM	640
	1 parcel (MTM-105431-HL)	Non-Federal	640
	1 parcel (MTM-105431-HM)	Non-Federal	320
	10 TOTAL		4,596.87

*parcels MTM-105431-HB, H6, H8 and HD contain both Federal and Non-Federal surface.

3.16 Minerals

3.16.1 Fluid Minerals

It is the policy of the BLM to make mineral resources available for development and to encourage development of these resources to meet national, regional, and local needs, consistent with national objectives of an adequate supply of minerals at reasonable prices. At the same time, the BLM strives to assure that mineral development occurs in a manner which minimizes environmental damage and provides for the reclamation of the lands affected.

Currently there are 1,560 Federal oil and gas leases covering approximately 955,572.612 acres in the MCFO. The number of acres leased and the number of leases can vary on daily basis as leases are relinquished, expired, or are terminated. Existing production activity occurs on approximately 20.4 (195,497.180 acres) percent of this lease acreage. Information on numbers and status of wells on these leases and well status and numbers of private and State wells within the external boundary of the field office is displayed in Table 11. Numbers of townships, lease acres within those townships, and development activity for all jurisdictions are summarized in Table 12.

Exploration and development activities would only occur after a lease is issued and the appropriate permit is approved. Exploration and development proposals would require completion of a separate environmental document to analyze specific proposals and site-specific resource concerns before BLM approved the appropriate permit.

Table 11. Existing Development Activity

	FEDERAL WELLS	PRIVATE AND STATE WELLS
Drilling Well(s)	9	125
Producing Gas Well(s)(including CBNG)	453	470
Producing Oil Well(s)	418	1890
Water Injection Well(s)	154	357
Shut-in Well(s)	154	1430
Temporarily Abandoned Well(s)	87	219

Table 12. Oil and Gas Leasing and Existing Development within Townships Containing Parcels

	Richland	Roosevelt	McCone
Number of Townships Containing Lease Parcels	6	7	2
Total Acres Within Applicable Township(s)	119,455	52,610	23,072
Acres of Federal Oil and Gas Minerals	28,834	309	2778
Percent of Township(s)	24.1%	0.6%	12.0%
Acres of Leased Federal Oil and Gas Minerals	24,076	141	2,698
Percent of Township(s)	20.2%	0.3%	11.7
Acres of Leased Federal Oil and Gas Minerals Suspended	Zero	Zero	Zero
Percent of Township(s)	0.0%	0.0%	0.0%
Federal Wells	7 producing oil wells (6 are horizontal wells), 3 shut in wells, 1 P&A wells, 5 temporarily abandoned wells.	1 P&A well	Zero
Private and State Wells	36 producing oil wells (35 are horizontal), 16 P&A wells, 1 service wells, 6 temporarily abandoned wells.	29 producing oil wells (24 are horizontal wells), 35 P&A wells, 4 service wells, 2 shut in wells, 8 temporarily abandoned wells.	1 P&A well.

	Prairie	Powder River
Number of Townships Containing Lease Parcels	4	4
Total Acres Within Applicable Township(s)	61,180	91,845
Acres of Federal Oil and Gas Minerals	26,576	50,833
Percent of Township(s)	43.4	55.3
Acres of Leased Federal Oil and Gas Minerals	Zero	24,981
Percent of Township(s)	0.0%	27.2
Acres of Leased Federal Oil and Gas Minerals Suspended	Zero	Zero
Percent of Township(s)	0.0%	0.0%
Federal Wells	Zero	2 Producing oil wells, 58 P&A wells.
Private and State Wells	3 P&A wells.	34 P&A wells, 2 service wells.

3.17 Special Designations

3.17.1 Lewis and Clark National Historic Trail

Two Lease parcels, MTM 105431-H8 and HB (947.3 acres), are located within a 3 mile sensitive Setting Consideration Zone (SCZ) around the Lewis and Clark National Historic Trail (NHT) and SRMA. The Lewis and Clark NHT is managed in accordance with the National Trail System Act of 1968, as amended (16 USC 1241-1251) to identify and protect the historic route and its historic remnants and artifacts for public use and enjoyment. The trail would be managed to preserve the historic and cultural resources that are related to the events that occurred during the Lewis and Clark Expedition. The National Park Service (NPS), who is the lead agency for trail administration, established the overall management vision through their Comprehensive Management Plan (1982) and Foundation Document (2012). BLM works collaboratively with NPS to manage trail resources in conformance with these plans and guidance thought BLM Manual 6280.

Any changes in the landscape within view of the Lewis and Clark NHT will be guided by Class II visual resource management objectives and the Lewis and Clark SRMA.

3.18 Social and Economic Conditions

3.18.1 Social and Environmental Justice

The social section focuses on the areas in the immediate vicinity of the parcels proposed for leasing. This area includes seven counties in eastern Montana: Daniels, Garfield, McCone, Prairie, Richland, Roosevelt, and Rosebud 80% of acres examined for leasing located in Prairie County. In 2010 this seven county region was reported to have a population of 35,274 people,

with more than 80% of the region's population living within Richland (10,425), Roosevelt (9,746), and Rosebud (9,233) Counties. Smaller Populations were reported in Daniels (1,751), Garfield (1,206), McCone (1,734), and Prairie (1,179) Counties (U.S. Census, 2010). Census data indicated that populations within this region declined between 2000 and 2010. Although all seven counties reported population losses during this time period, losses in Daniels (13.2%), Garfield (5.7%) and McCone (12.3%) counties were substantially greater than those in Prairie (1.7%), Richland (0.8%), Roosevelt (1.8%), and Rosebud (1.6%) (US Department of Commerce, 2012). While Montana is often characterized as a rural state with a population density of 6.8 persons per square mile, all of the seven counties with land proposed for oil and gas leasing were reported to have fewer than 6.8 persons per square mile in 2010. Of these seven counties, only Daniels (1.2), Richland (4.7), Roosevelt (4.4), and Rosebud (1.8) had population densities greater than 1. The county seats for these counties include Scobey in Daniels County (1,107), Jordan in Garfield County (352), Circle in McCone County (526), Terry in Prairie County (605), Sidney in Richland County (4,843), Wolf Point in Roosevelt County (2,621), and Forsyth in Rosebud County (1,777) (U.S. Census, 2010).

Currently oil and gas leasing and production are taking place on public and private lands within these seven counties. Approximately half of the acres being considered for this lease sale are under BLM ownership, with an addition 2,876 acres under split ownership between BLM and private estates. Interest in oil and gas development in this region has significantly increased over the last five years because of its proximity to the Bakken formation which extends from the Williston Basin in western North Dakota to northeastern Montana. Richland, MT, which is adjacent to the Williston Basin, has had the highest oil and gas production on federal lands of any of county in eastern Montana. Most of the oil and gas industry support services for eastern Montana occur in Glendive, Sidney, and Miles City, Montana, and Williston and Dickinson, North Dakota.

According to the 2010 Census populations in the seven counties with land proposed for oil and gas leasing were made up of individuals who identified with one of three racial groups: White alone, American Indian alone, or of Two or more races. While 70% of the total population in this seven-county region identified themselves as White alone, individuals identifying themselves at White accounted for more than 95% of the total population in five of the seven counties (Daniels, Garfield, McCone, Prairie, and Richland) (U.S. Department of Commerce, 2012). Populations in Roosevelt and Rosebud counties were more diverse in 2010 with large American Indian populations from the Cheyenne and Sioux tribes. Roosevelt and Rosebud counties 2010 populations were made up of 37% and 61% White alone, 49% and 33% American Indian alone, and 13% and 3% two or more races (U.S. Department of Commerce, 2012). While the percent of Montana residents (14.5%) living below the poverty line in 2010 was comparable to the nation poverty rate (13.8%), the poverty rate of the seven-county region in eastern Montana (17%) was above state and national levels. The relatively high regional poverty rate was driven by poverty levels in Prairie (16.9%), Roosevelt (21.5%), and Rosebud (18.5%) counties; while poverty in Daniels (14.1%), Garfield (10.7%), McCone (8.6), and Richland (13.5%) counties remained relatively low in 2010 (U.S. Department of Commerce, 2012).

The social environment of these counties is described in detail in the Socioeconomic Baseline Report for the Miles City Field Office RMP and EIS (prepared for the DOI, BLM, MCFO, June, 2005).

3.18.2 Economics

Certain existing demographic and economic features influence and define the nature of local economic and social activity. Among these features are the local population, the presence and proximity of cities or regional business centers, longstanding industries, infrastructure, predominant land and water features, and unique area amenities. Several additional parcels in McCone, Power River, Prairie, Richland and Roosevelt counties have been nominated for leasing in the October 2014 lease sale. While the majority of nominated land is unoccupied there are social and economic linkages which connect nominated parcels to communities in the surrounding area. To examine how leasing proposed under the alternatives will affect the local economy, the analysis area was expanded to include Williams County, North Dakota since Williston, ND is the largest business center near the affected communities, especially for oil and gas related activities, and is the major oil and gas service center for activity in the five counties above. Custer and Dawson counties in Montana were also included to create a contiguous analysis area.

In 2012, the 8-county analysis area was estimated to have a total population of 74,192 people, with 32,624 households earning an average annual household income of \$149,626 (IMPLAN, 2014). Twenty-five percent of the area's total population lived in Williston, ND (18,532 people). In 2012, the 8-county area economy supported approximately 71,948 jobs in 183 industrial sectors, equating to approximately 2.3 people or 2.2 jobs per household. The top five industries operating in the local economy included: support activities for oil and gas operations, wholesale trade, drilling oil and gas wells, State and local government, and truck transportation (IMPLAN, 2014). A large share of the economic activity in the region occurs in Williams County which contains Williston, ND, the largest business center and the epicenter of recent oil and gas exploration and development.

Parcels nominated for leasing in October 2014 are located in the eastern Montana counties of McCone, Powder River, Prairie, Richland and Roosevelt. Between 2009 and 2013, these counties produced an annual average of 16.4 million bbls of oil and 16.5 million mcf of natural gas, with the majority of production occurring in Richland County. Over the last 24 months (4/2012-4/2014), the Montana Board of Oil and Gas reported that 372 permits for activities associated with oil and gas wells were processed for these five counties. Of the 372 permits processed for this area, 35% were associated with existing producing wells and 28% were related to recently spudded wells. While these permits can be associated with several types of well, only 4% were reported to be unrelated to oil (i.e natural gas, injection or monitoring, or dry hole) (MT DNR, 2014). While some oil and gas related activities have been permitted in the Southeastern county of Powder River, more than 99% of permitted activity is associated with wells in the Three Forks Group. These subsurface deposits stretch across the Williston Basin from southern Saskatchewan, Canada to eastern Montana and western North Dakota. The overwhelming majority of recently completed wells are located in the sub-unit of the Three-Forks known as the Bakken formation.

The widespread adoption of horizontal drilling and other recent technological advances have significantly increased the capability and cost effectiveness of extracting fluid minerals across the Williston Basin. The recent surge of interest in commercial development of the Bakken's deposits has rapidly transformed the region's physical, cultural and economic landscapes. Eastern Montana and Western North Dakota have become increasingly specialized in industries that support and service the oil and gas sector, enabling the oil and gas industry to become the driving force behind the region's economy. The exploration, development, and production of fluid minerals directly and indirectly support thousands of jobs and millions of dollars in labor income throughout Eastern Montana and Western North Dakota. Although Federal minerals in the five counties with parcels nominated for leasing are associated with only a fraction of the region's oil and gas activity, the leasing and development of these minerals supports local employment and income and generates public revenue for many surrounding communities. The economic contributions of Federal fluid minerals are largely influenced by the number of acres leased and estimated levels of production and can be measured in terms of the jobs, income, and public revenue it generates.

Mineral rights can be owned by private individuals, corporations, Indian tribes, or by local, State, or Federal Governments. Typically companies specializing in the development and extraction of oil and gas lease the mineral rights for a particular parcel from the owner of the mineral rights. As of April, 2014, 434,866 acres were leased from the BLM for oil and gas development in McCone, Powder River, Prairie, Richland, and Roosevelt counties. Federal oil and gas leases are generally issued for 10 years unless drilling activities result in one or more producing wells or the lease is part of a collective agreement and incorporated into a field or unit. Once production of federal minerals from a lease has begun, the lease is considered to be held by production and the lessee is required to make royalty payments to the Federal Government. Of 434,866 acres leased from the BLM in the five counties, 57,664 acres were held by production at the time of this analysis.

Leasing mineral rights for the development of Federal minerals generates public revenue through the bonus bids paid at lease auctions and annual rents collected on leased parcels not held by production. Nominated parcels approved for leasing are offered by the BLM at a minimum rate of \$2.00 per acre at the lease sale. These sales are competitive and parcels with high potential for oil and gas production command bonus bids in excess of the minimum bid. Auctions for mineral rights from 2009 to 2013 in the five counties have yielded an average bonus bid of \$295 per acre. In addition to bonus bids, lessees are required to pay rent annually until production begins on the leased parcel, or until the lease expires. These rent payments are equal to \$1.50 an acre for the first five years and \$2.00 an acre for the second five years of the lease. Total annual lease bonus and rental revenue to the Federal Government from leasing Federal minerals in the five counties with nominated parcels is estimated to be approximately \$865,000.

Forty-nine percent of these Federal leasing revenues from public domain minerals are distributed to the State who distributes 25 percent of federal revenue from public domain minerals back to the counties where the leases exist. About 94 percent of the leased Federal minerals within the Miles City Field Office are leased on public domain minerals. With federally acquired minerals (acquired under Bankhead Jones authority), 25 percent of Federal revenues are distributed directly to the appropriate counties. The Federal Government collects an estimated annual

average of about \$865,000 in bonus bids and rent from BLM leased minerals in the five counties. Under current conditions, it is estimated that about \$411,000 in public revenue is redistributed back to the State who then distributes a portion of this revenue back to McCone, Powder River, Prairie, Richland and Roosevelt Counties. Between leasing revenue collected from public domain and acquired minerals, it is estimated that these five counties receive more than \$112,000 from federal mineral leasing auction and rent revenue on annual average.

As mentioned above, Federal oil and gas production in Montana is subject to production taxes or royalties. The Federal oil and gas royalties on production from public domain minerals equal 12.5 percent of the value of production (43 CFR 3103.3.1). Forty-nine percent of these royalties from public domain minerals are distributed to the State, of which 25 percent is distributed back to the county of production (Title 17-3-240, MCA). If production comes from acquired Federal minerals under the Bankhead Jones authority, 25 percent of the Federal revenues are distributed directly to the counties of production.

Although the MCFO's October 2014 lease sale could result in additional mineral leasing in McCone, Powder River, Prairie, Richland, and Roosevelt counties, many of the workers and companies likely to provide support services for the exploration and development of newly leased minerals will spread throughout an 8-county area which includes Williams, ND and Custer and Dawson, MT. The economic contribution of oil and gas related activities to this 8-county local economy can be measured by estimating the employment and labor income generated by 1) payments to counties associated with the leasing and rent of Federal minerals, 2) local royalty payments associated with production of Federal oil and gas, and 3) economic activity generated from drilling and associated activities. Activities related to oil and gas leasing, exploration, development, and production form a basic industry that brings money into the State and region and creates jobs in other sectors. As of 2012, the extraction of oil and natural gas (NAICS sector 20), drilling oil and gas wells (NAICS sector 28), and support activities for oil and gas operations (NAICS sector 29) supported an estimated 14,280 jobs¹ and \$1.57 billion in employee compensation and proprietor income in the 8-county local economy (IMPLAN, 2014).

Currently, the BLM leases 434,866 acres of Federal minerals in McCone, Powder River, Prairie, Richland, and Roosevelt counties. Total Federal revenues from Federal oil and gas leasing, rents, and royalty payments associated with the leasing of these Federal minerals averages an estimated \$12 million. Federal revenues disbursed to the State of Montana on annual average is estimated \$5.8 million per year and those redistributed back to the five counties are estimated to be \$1.6 million on annual average. These revenues help fund traditional county functions such as enforcing laws, administering justice, collecting and disbursing tax funds, providing for orderly elections, maintaining roads and highways, providing fire protection, and/or keeping records. Other county functions that may be funded include administering primary and secondary education and operating clinics/hospitals, county libraries, county airports, local landfills, and county health systems.

¹ IMPLAN job estimates are not full-time equivalents and include all full-time, part-time, and temporary positions supported oil and gas activities within the planning area. These activities may support, or partially support a number of jobs annually. In this respect, 1 job in IMPLAN lasting 12 months = 2 jobs lasting 6 months each = 3 jobs lasting 4 months

On annual average the leasing, development, and extraction of Federal minerals administered by the BLM supports 46 local jobs (full and part-time) and about \$3 million in local labor income within the 8-county local economy. This amounts to about 0.06 percent of the local employment and 0.06 percent of local labor and proprietor's income. Table 13 shows the current contributions of leasing BLM oil and gas minerals and the associated exploration, development, and production of the MCFO of BLM oil and gas minerals to the eight counties that make up the local economy.

Table 13. Current Contributions of BLM Oil and Gas Leasing, Exploration, Development, and Production to the 8-County Local Economy

Industry	Employment (Jobs)		Labor Income (Thousands of 2012 dollars)	
	Area Totals	BLM O&G-Related	Area Totals	BLM O&G-Related
Agriculture	5,737	0	\$148,789	\$1
Mining	14,442	17	\$1,583,665	\$1,501
Utilities	416	0	\$46,173	\$27
Construction	6,051	3	\$481,624	\$271
Manufacturing	1,295	0	\$77,629	\$5
Wholesale Trade	4,097	1	\$412,553	\$57
Transportation & Warehousing	4,925	1	\$441,881	\$34
Retail Trade	5,407	2	\$203,717	\$67
Information	554	0	\$25,846	\$12
Finance & Insurance	1,938	1	\$70,248	\$23
Real Estate & Rental & Leasing	1,958	0	\$173,992	\$26
Prof, Scientific, & Tech Services	2,371	1	\$151,847	\$72
Mngt of Companies	41	0	\$3,541	\$2
Admin, Waste Mngt & Rem Serv	1,591	1	\$78,164	\$20
Educational Services	578	0	\$10,752	\$4
Health Care & Social Assistance	4,513	2	\$210,468	\$81
Arts, Entertainment, and Rec	1,040	0	\$15,411	\$3
Accommodation & Food Services	4,278	1	\$108,610	\$30
Other Services	3,141	1	\$98,698	\$31
Government	7,576	14	\$371,145	\$659
Total	71,948	46	\$4,714,754	\$2,927
BLM as Percent of Total	---	0.06%	---	0.06%

IMPLAN, 2014 database

4.0 ENVIRONMENTAL IMPACTS

4.1 Assumptions and Reasonably Foreseeable Development Scenario Summary

This chapter describes the environmental effects (direct, indirect, and cumulative) that would result from the alternatives. This analysis is tiered to the final environmental impact statement (EIS) for the Dillon RMP/ROD. The analysis contained within that RMP/FEIS remains adequate. The RMP determined which areas are available for oil and gas leasing and under what conditions those leases are to be offered and sold.

The act of leasing parcels would not impact the resources. The only direct effects of leasing are creation of valid existing right and related to revenue generated by the lease sale receipts.

Potential indirect effects associated with a lease sale would result from any future developments. The BLM assumes there is a high interest in development of any leased parcels but, even if lease parcels are leased, it is speculative to assume development would actually occur, and if so, it is speculative to assume where specific wells would be drilled and where facilities would be placed. This would not be determined until the BLM receives an APD in which detailed information about proposed wells and facilities would be provided for particular leases.

Upon receipt of an APD, the BLM would initiate a more site-specific NEPA analysis with public review opportunities to more fully analyze and disclose site-specific effects of specifically identified activities. In all potential exploration and development scenarios, the BLM would require the use of BMPs documented in “Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development” (USDI and USDA 2007), also known as the “Gold Book.” The BLM could also identify APD COAs, based on site-specific analysis that could include moving the well location, restrict timing of the project, or require other reasonable measures to minimize adverse impacts (43 CFR 3101.1-2 Surface use rights; Lease Form 3100-11, Section 6) to protect sensitive resources, and to ensure compliance with laws, regulations, and land use plans.

For split-estate leases, the BLM would notify the private landowners that oil and gas exploration or development activities are proposed on their lands and they are encouraged to attend the onsite inspection to discuss the proposed activities. In the event of activity on such split estate leases, the lessee and/or operator would be responsible for adhering to BLM requirements as well as reaching an agreement with the private surface landowners regarding access, surface disturbance, and reclamation.

The RFD for this EA (Appendix C) is based on information contained in the RFD developed in 2005 and revised in 2012 for the MCFO RMP. The RFD prepared for the MCFO RMP contains the number of potential oil and gas wells that could be drilled and produced in the MCFO area and used to analyze the potential number of wells drilled for the 18 nominated lease parcels. The projected number of wells is used to conduct analysis for economic resources. These well numbers are only an estimate based on historical drilling and geologic data. A detailed description of the RFD forecast for this EA is found in Appendix C.

No surface disturbance would occur as a result of issuing leases. For analysis purposes, cultural resources use the potential number of acres disturbed by exploration and development activities is shown in Tables D-1 in Appendix D to determine the number of cultural site potentially impacted within the nominated lease parcels. The potential acres of disturbance reflect acres typically disturbed by construction, drilling, and production activities, including infrastructure installation throughout the MCFO. Typical exploration and development activities and associated acres of disturbance were used as assumptions for analysis purposes in this EA.

The assumptions were not applied to Alternative A because the lease parcels would not be offered for lease; therefore, no wells would be drilled or produced on the lease parcel, and no surface disturbance would occur on those lands from exploration and development activities).

Environmental consequences are discussed below by alternative to the extent possible at this time for the resources described in Chapter 3. As per NEPA regulations at 40 CFR 1502.14(f), 40 CFR 1502.16(h), and 40 CFR 1508.20, mitigation measures to reduce, avoid, or minimize potential impacts are identified by resource below.

4.2 Alternative A (No Action Alternative)

4.2.1 Direct Effects Common to All Resources, not including Economics

Under Alternative A, the 18 parcels, covering 7,945.28 surveyed Federal mineral acres (3,637.97 surveyed BLM administered surface and 4,307.31 surveyed private surface), would not be offered for competitive oil and gas lease sale. Under this alternative, the State and private minerals could still be leased in surrounding areas. Surface management would remain the same and ongoing oil and gas development would continue on surrounding Federal, private, and State leases.

There would not be new impacts from oil and gas exploration or production activities on the Federal lease parcel lands at this time. No additional natural gas or crude oil would enter the public markets, and no royalties would accrue to the Federal or State treasuries from the parcel lands. The No Action Alternative would result in the continuation of the current land and resource uses on the lease parcels.

Except for Economic resources, described below, no further analysis of the No Action Alternative is presented for resources on parcel lands.

4.2.2 Economics

4.2.2.1 Direct and Indirect Effects:

The economic contributions of activities associated with oil and gas development on BLM administered Federal minerals are measured in terms of the employment and labor income generated by 1) payments to counties associated with the leasing and rent of Federal minerals, 2) royalty payments associated with production of Federal oil and gas, and 3) economic activity generated from drilling and associated activities. The first two described contributions would occur upon issuance of the lease; the third contribution would only occur if development occurred. Forward and backward linkages between businesses and people in communities surrounding parcels leased for the development of Federal minerals has enabled the oil and gas industry to attract new revenue to the region, growing the local economy and creating new

employment and income opportunities in a wide range of industrial sectors. Table 14 is a summary of local revenues, employment, and labor income impacts of each alternative.

Alternative A is the no action alternative. Under Alternative A, no additional parcels would be leased and no additional public revenue would be generated. The economic contributions of activities associated with oil and gas development would remain consistent with existing conditions described in the Economics section of Chapter 3. Economic effects are summarized and displayed in comparative form in Table 14.

Table 14. Summary Comparison of Estimated Average Annual Economic Impacts

Alternative	Acres Leased	Change in Local Revenue to Counties	Change in Total Employment (full and part-time jobs)	Change in Total Labor Income
A	0	0	0	0
B	7,945	\$38,399	2	\$61,000
C	1,397	\$5,465	0	\$12,000

*These impacts would be in addition to impacts from existing Federal leases, rents, royalties and related activities.

4.2.2.2 Cumulative Effects:

Cumulative Effects:

The lack of measurable direct and indirect effects to economic conditions under the No Action Alternative translates to a lack of measurable cumulative effects. Under this alternative the BLM will not make any additional Federal minerals available for leasing and Federal minerals leased from the MCFO will likely continue at existing levels. Current levels of BLM mineral leasing in McCone, Powder River, Prairie, Richland, and Roosevelt counties support jobs and income in the 8-county local economy and the economic contributions of oil and gas activities associated with these leases will continue to be similar to those discussed in Chapter 3.

Cumulative economic impacts associated with Federal mineral leasing under the alternatives are shown below in Table 15 and Table 16.

Table 15. Summary Comparison of Cumulative Annual Economic Impacts by Alternative

Activity	<u>A</u>	<u>B</u>	<u>C</u>
Existing Acres leased	434,866	434,866	434,866
Acres that would be leased based on this EA	0	7,945	1,397
Total acres leased	434,866	442,811	436,263
Acres held by production	57,664	57,664	57,664
Total acres leased for which lease rents would be paid	377,202	385,147	378,599
Total average annual Federal lease and rental revenue	\$660,104	\$954,961	\$871,313
Average annual distribution to State*	\$313,945	\$454,179	\$414,397
Average annual distribution to Counties**	\$85,912	\$124,288	\$113,401
Average annual oil production (bbl)***	868,935	884,810	871,726
Average annual gas production (MCF)***	2,188,938	2,228,930	2,195,970

Total Average annual Federal O&G royalties	\$11,250,381	\$11,455,925	\$11,286,522
Average annual distribution to State*	\$5,350,681	\$5,448,438	\$5,367,870
Average annual distribution to Counties**	\$1,464,237	\$1,490,989	\$1,468,941
Total average annual Federal Revenues	\$11,910,484	\$12,410,885	\$12,157,835
Total average annual State Revenues	\$5,664,626	\$5,902,617	\$5,782,267
Total average annual revenue distributed to counties	\$1,550,149	\$1,615,277	\$1,582,342

*49 percent of Federal revenue from public domain minerals and 25 percent of Federal revenue from acquired minerals are distributed back to the State.

**Montana distributes 25 percent of public domain revenue and all of acquired mineral revenue received from the Federal Government back to the counties where revenue was generated.

***Estimated as BLM's share of Federal minerals production in McCone, Powder River, Prairie, Richland and Roosevelt counties.

Table 16. Summary Comparison of Employment and Income Supported by BLM Minerals in McCone, Powder River, Prairie, Richland and Roosevelt Counties.

Industry	Total Jobs Supported			Total Income Supported (\$1000)		
	Alt. A	Alt. B	Alt. C	Alt. A	Alt. B	Alt. C
Total Contribution of BLM Minerals	45	47	45	\$2,894	\$2,969	\$2,920

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4.3 Alternative B (Proposed Action)

Under Alternative B, 18 lease parcels of Federal minerals for oil and gas leasing, covering 7,945.28 surveyed Federal mineral acres (3,637.97 surveyed BLM administered surface and 4,307.31 surveyed private surface) would be offered for competitive oil and gas lease sale. No parcels would be deferred.

4.3.1 Direct Effects Common to All Resources

The action of leasing the parcels in Alternative B would, in and of itself, have no direct impact on resources. Direct effects of leasing are the creation of a valid existing right and those related to the revenue generated by the lease sale receipts.

4.3.2 Indirect Effects Common to All Resources

Any potential effects on resources from the sale of leases would occur during lease exploration and development activities, which would be subject to future BLM decision-making and NEPA analysis upon receipt of an APD or sundry notice.

Oil and gas exploration and development activities such as construction, drilling, production, infrastructure installation, vehicle traffic and reclamation could be indirect effects from leasing the lease parcels in Alternative B. As mentioned above, it is speculative to make assumptions about whether a particular lease parcel would be sold and, even if so, it is speculative to assume when, where, how, or if future surface disturbing activities associated with oil and gas exploration and development such as well sites, roads, facilities, and associated infrastructure would be proposed. It is also not known how many wells, if any, would be drilled and/or completed, the types of technologies and equipment would be used and the types of

infrastructure needed for production of oil and gas. Thus, the types, magnitude and duration of potential impacts cannot be precisely quantified at this time, and would vary according to many factors.

Typical impacts to resources from oil and gas exploration and development activities such as well sites, roads, facilities, and associated infrastructure are described in the Miles City Oil & Gas Amendment/EIS (1994), the Big Dry RMP (1996), the Powder River RMP (1985), the Montana Statewide Oil & Gas Amendment/EIS (2003) and the Supplement (2008) to that document.

4.3.3 Air Resources

4.3.3.1 Direct and Indirect Effects

4.3.3.1.1 Air Quality

Leasing the parcels would have no direct impacts on air quality. Any potential effects from sale of lease parcels could occur at the time the leases are developed.

Potential impacts of development could include increased airborne soil particles blown from new well pads or roads; exhaust emissions from drilling equipment, compressors, vehicles, and dehydration and separation facilities, as well as potential releases of GHGs and VOCs during drilling or production activities. The amount of increased emissions cannot be precisely quantified at this time since it is not known for certain how many wells might be drilled, the types of equipment needed if a well were to be completed successfully (e.g., compressor, separator, dehydrator), or what technologies may be employed by a given company for drilling any new wells. The degree of impact would also vary according to the characteristics of the geologic formations from which production occurs, as well as the scope of specific activities proposed in an APD.

Current monitoring data show that criteria pollutants concentrations are below applicable air quality standards, indicating good air quality. The potential level of development and mitigation described below is expected to maintain this level of air quality by limiting emissions. In addition, pollutants would be regulated through the use of State-issued air quality permits or air quality registration processes developed to maintain air quality below applicable standards.

4.3.3.1.2 Greenhouse Gas Emissions at the MCFO and Project Scales

Sources of GHGs associated with development of lease parcels could include construction activities, operations, and facility maintenance in the course of oil and gas exploration, development, and production. Estimated GHG emissions are discussed for these specific aspects of oil and gas activity because the BLM has direct involvement in these steps. However, the current proposed activity is to offer parcels for lease. No specific development activities are currently proposed or potentially being decided upon for any parcels being considered in this EA. Potential development activities would be analyzed if the BLM receives an APD on any of the parcels considered here.

Anticipated GHG emissions presented in this section are taken from the Climate Change SIR, 2010. Data are derived from emission calculators developed by air quality specialists at the BLM National Operations Center in Denver, Colorado, based on methods described in the

Climate Change SIR (2010). Based on the assumptions summarized in the SIR for the MCFO RFD, Table 16 discloses projected annual GHG source emissions from BLM-permitted activities associated with the RFD.

Table 17. The BLM Projected Annual GHG Emissions Associated With Oil and Gas Exploration and Development Activity in the MCFO.

Source	BLM Long-Term GHG Emissions in tons/year				Emissions (metric tons/yr)
	CO ₂	CH ₄	N ₂ O	CO ₂ e	CO ₂ e
Conventional Natural Gas	158,154.7	1,572.8	1.2	190,984.1	173,817.6
Coal Bed Natural Gas	268,477.4	5,194.6	0.9	377,826.5	342,855.24
Oil	91,689.0	562.6	0.5	103,663.3	94,068.3
Total	518,321.1	7,330	2.6	672,473.9	610,741.1

To estimate GHG emissions associated with the action alternatives, the following approach was used:

1. The proportion of each alternative relative to the total RFD was calculated based on total acreage of parcels under consideration for leasing relative to the total acreage of Federal mineral acreage available for leasing in the RFD.
2. This ratio was then used as a multiplier with the total estimated GHG emissions for the entire RFD (with the highest year emission output used) to estimate GHG emissions for that particular alternative.

Under Alternative B, approximately 7,945 acres of lease parcels with Federal minerals would be leased. These acres constitute approximately 0.14 percent of the total Federal mineral estate of approximately 5,798,000 acres identified in the MCFO RFD. Therefore, based on the approach described above to estimate GHG emissions, 0.14 percent of the RFD for this EA total estimated BLM emissions of approximately 610,741 metric tons/year would be approximately 837 metric tons/year of CO₂e if the parcels within Alternative B were to be developed.

4.3.3.1.3 Climate Change

The assessment of GHG emissions and climate change is in its formative phase. As summarized in the Climate Change SIR, climate change impacts can be predicted with much more certainty over global or continental scales. Existing models have difficulty reliably simulating and attributing observed temperature changes at small scales. On smaller scales, natural climate variability is relatively larger, making it harder to distinguish changes expected due to external forcings (such as contributions from local activities to GHGs). Uncertainties in local forcings and feedbacks also make it difficult to estimate the contribution of GHG increases to observed small-scale temperature changes (Climate Change SIR 2010).

It is currently not possible to know with certainty the net impacts from lease parcel development on climate. The inconsistency in results of scientific models used to predict climate change at the global scale, coupled with the lack of scientific models designed to predict climate change on regional or local scales, limits the ability to quantify potential future impacts of decisions made at this level. It is therefore beyond the scope of existing science to relate a specific source of

GHG emission or sequestration with the creation or mitigation of any specific climate-related environmental effects. Although the effects of GHG emissions in the global aggregate are well-documented, it is currently impossible to determine what specific effect GHG emissions resulting from a particular activity might have on the environment. For additional information on environmental effects typically attributed to climate change, please refer to the cumulative effects discussion below.

While it is not possible to predict effects on climate change of potential GHG emissions discussed above in the event of lease parcel development for alternatives considered in this EA, the act of leasing does not produce any GHG emissions in and of itself. Releases of GHGs could occur at the exploration/development stage.

4.3.3.2 Mitigation

The BLM encourages industry to incorporate and implement BMPs to reduce impacts to air quality by reducing emissions, surface disturbances, and dust from field production and operations. Measures would also be required as COAs on permits by either the BLM or the applicable State air quality regulatory agency. The BLM also manages venting and flaring of gas from Federal wells as described in the provisions of Notice to Lessees (NTL) 4A, Royalty or Compensation for Oil and Gas Lost.

Some of the following measures could be imposed at the development stage:

- flaring or incinerating hydrocarbon gases at high temperatures to reduce emissions of incomplete combustion;
- emission control equipment of a minimum 95 percent efficiency on all condensate storage batteries;
- emission control equipment of a minimum 95 percent efficiency on dehydration units, pneumatic pumps, produced water tanks;
- vapor recovery systems where petroleum liquids are stored;
- tier II or greater, natural gas or electric drill rig engines;
- secondary controls on drill rig engines;
- no-bleed pneumatic controllers (most effective and cost effective technologies available for reducing VOCs);
- gas or electric turbines rather than internal combustions engines for compressors;
- NO_x emission controls for all new and replaced internal combustion oil and gas field engines;
- water dirt and gravel roads during periods of high use and control speed limits to reduce fugitive dust emissions;
- interim reclamation to re-vegetate areas of the pad not required for production facilities and to reduce the amount of dust from the pads.
- co-located wells and production facilities to reduce new surface disturbance;
- directional drilling and horizontal completion technologies whereby one well provides access to petroleum resources that would normally require the drilling of several vertical wellbores;
- gas-fired or electrified pump jack engines;
- velocity tubing strings;

- cleaner technologies on completion activities (i.e. green completions), and other ancillary sources;
- centralized tank batteries and multi-phase gathering systems to reduce truck traffic;
- forward looking infrared (FLIR) technology to detect fugitive emissions; and
- air monitoring for NO_x and ozone.

More specific to reducing GHG emissions, Section 6 of the Climate Change SIR identifies and describes in detail commonly used technologies to reduce methane emissions from natural gas, coal bed natural gas, and oil production operations. Technologies discussed in the Climate Change SIR and as summarized below in Table 17 (reproduced from Table 6-2 in Climate Change SIR) display common methane emission technologies reported under the EPA Natural Gas STAR Program and associated emission reduction, cost, maintenance and payback data.

Table 18. Selected Methane Emission Reductions Reported Under the USEPA Natural Gas STAR Program ¹

Source Type / Technology	Annual Methane Emission Reduction ¹ (Mcf/yr)	Capital Cost Including Installation (\$)	Annual Operating and Maintenance Cost (\$)	Payback (Years or Months)	Payback Gas Price Basis (\$/Mcf)
Wells					
Reduced emission (green) completion	7,000 ²	\$1K – \$10K	>\$1,000	1 – 3 yr	\$3
Plunger lift systems	630	\$2.6K – \$10K	NR	2 – 14 mo	\$7
Gas well smart automation system	1,000	\$1.2K	\$0.1K – \$1K	1 – 3 yr	\$3
Gas well foaming	2,520	>\$10K	\$0.1K – \$1K	3 – 10 yr	NR
Tanks					
Vapor recovery units on crude oil tanks	4,900 – 96,000	\$35K – \$104K	\$7K – \$17K	3 – 19 mo	\$7
Consolidate crude oil production and water storage tanks	4,200	>\$10K	<\$0.1K	1 – 3 yr	NR
Glycol Dehydrators					
Flash tank separators	237 – 10,643	\$5K – \$9.8K	Negligible	4 – 51 mo	\$7
Reducing glycol circulation rate	394 – 39,420	Negligible	Negligible	Immediate	\$7
Zero-emission dehydrators	31,400	>\$10K	>\$1K	0 – 1 yr	NR
Pneumatic Devices and Controls					
Replace high-bleed devices with low-bleed devices					
End-of-life replacement	50 – 200	\$0.2K – \$0.3K	Negligible	3 – 8 mo	\$7
Early replacement	260	\$1.9K	Negligible	13 mo	\$7
Retrofit	230	\$0.7K	Negligible	6 mo	\$7
Maintenance	45 – 260	Negl. to \$0.5K	Negligible	0 – 4 mo	\$7
Convert to instrument air	20,000 (per facility)	\$60K	Negligible	6 mo	\$7
Convert to mechanical control systems	500	<\$1K	<\$0.1K	0 – 1 yr	NR

Table 18. Selected Methane Emission Reductions Reported Under the USEPA Natural Gas STAR Program ¹

Source Type / Technology	Annual Methane Emission Reduction ¹ (Mcf/yr)	Capital Cost Including Installation (\$)	Annual Operating and Maintenance Cost (\$)	Payback (Years or Months)	Payback Gas Price Basis (\$/Mcf)
Valves					
Test and repair pressure safety valves	170	NR	\$0.1K – \$1K	3 – 10 yr	NR
Inspect and repair compressor station blowdown valves	2,000	<\$1K	\$0.1K – \$1K	0 – 1 yr	NR
Compressors					
Install electric compressors	40 – 16,000	>\$10K	>\$1K	>10 yr	NR
Replace centrifugal compressor wet seals with dry seals	45,120	\$324K	Negligible	10 mo	\$7
Flare Installation	2,000	>\$10K	>\$1K	None	NR

Source: Multiple EPA Natural Gas STAR Program documents. Individual documents are referenced in Climate Change SIR (2010).

¹ Unless otherwise noted, emission reductions are given on a per-device basis (e.g., per well, per dehydrator, per valve, etc).

² Emission reduction is per completion, rather than per year.

K = 1,000

mo = months

Mcf = thousand cubic feet of methane

NR = not reported

yr = year

In the context of the oil sector, additional mitigation measures to reduce GHG emissions include methane reinjection and CO₂ injection. These measures are discussed in more detail in Section 6.0 of the Climate Change SIR (2010).

In an effort to disclose potential future GHG emission reductions that might be feasible, the BLM estimated GHG emission reductions based on the RFD for the MCFO. For emission sources subject to BLM (Federal) jurisdiction, the estimated emission reductions represent approximately 51 percent reduction in total GHG emissions compared to the estimated MCFO Federal GHG emission inventory (Climate Change SIR, as updated October 2010, Section 6.5 and Table 6-3). The emission reductions technologies and practices are identified as mitigation measures that could be imposed during development. Furthermore, the EPA is expected to promulgate new Federal air quality regulations that would require GHG emission reductions from many oil and gas sources.

4.3.4 Soil Resources

4.3.4.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on soil resources. Any potential effects from the sale of leases would occur at the time the leases are developed.

Land uses associated with oil and gas exploration and development could cause surface disturbances. Such acts result in reduced ground cover, soil mixing, compaction, or removal, exposing soils to accelerated erosion by wind and water, resulting in the irretrievable loss of topsoil and nutrients and potentially resulting in mass movement or sedimentation. Surface disturbances also change soil structure, heterogeneity (variable characteristics), temperature

regimes, nutrient cycling, biotic richness, and diversity. Along with this, mixed soils have decreased bulk density, and altered porosity, infiltration, air-water relationships, salt content, and pH (Perrow and Davy, 2003; Bainbridge 2007). Soil compaction results in increased bulk density, and reduced porosity, infiltration, moisture, air, nutrient cycling, productivity, and biotic activity (Logan 2001; 2003; 2007). Altering such characteristics reduces the soil system's ability to withstand future disturbances (e.g., wildfire, drought, high precipitation events, etc.).

The probability and magnitude of these effects are dependent upon local site characteristics, climatic events, and the specific mitigation applied to the project. Within 2-5 years following restoration, vegetative cover and rates of erosion would return to pre-disturbance conditions (FSEIS 2008). Exceptions would be sites that have a low potential for restoration (apx. less than 1 percent), which would require unconventional and/or site-specific restoration measures.

4.3.4.2 Mitigation

Measures would be taken to reduce, avoid, or minimize potential impacts to soil resources from exploration and development activities. Prior to authorization, proposed actions would be evaluated on a case-by-case basis and would be subject to mitigation measures in order to maintain the soil system. Mitigation would include avoiding areas poorly suited to reclamation, limiting the total area of disturbance, rapid reclamation, erosion/sediment control, soil salvage, decompaction, revegetation, weed control, slope stabilization, surface roughening, and fencing.

4.3.5 Water Resources

4.3.5.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on water resources. Any potential effects from sale of lease parcels would occur at the time the leases are developed.

Surface Water:

The magnitude of the impacts to water resources would be dependent on the specific activity, season, proximity to waterbodies, location in the watershed, upland and riparian vegetation condition, effectiveness of mitigation, and the time until reclamation success. Surface disturbance effects typically are localized, short-term, and occur from the time of implementation through vegetation reestablishment. As acres of surface-disturbance increase within a watershed, so would the potential effects on water resources.

Oil and gas exploration and development of a lease parcel would cause the removal of vegetation, soil compaction, and soil disturbance in uplands within the watershed, 100-year floodplains of non-major streams, and non-riparian, ephemeral waterbodies. The potential effects from these activities would be accelerated erosion, increased overland flow, decreased infiltration, increased water temperature, channelization, and water quality degradation associated with increased sedimentation, turbidity, nutrients, metals, and other pollutants. Erosion potential could be further increased in the long term by soil compaction and low permeability surfacing (e.g., roads and well pads) which increases the energy and amount of overland flow and decreases infiltration, which in turn changes flow characteristics, reduces groundwater recharge, and increases sedimentation and erosion (MDEQ 2012).

Groundwater:

Spills or produced fluids could have long-term impacts to surface and ground water resources. Oil and gas exploration/development could potentially contaminate aquifers with salts, drilling fluids, fluids and gases from other formations, detergents, solvents, hydrocarbons, metals, and nutrients; change vertical and horizontal aquifer permeability; and increase hydrologic communication with adjacent aquifers (EPA 2004). Groundwater removal could result in a depletion of flow in nearby streams and springs if the aquifer is hydraulically connected to such features. Typically, produced water from conventional oil and gas wells is from a depth below useable aquifers or coal seams (FSEIS 2008).

Well bores would most likely pass through useable groundwater. Potential impacts to groundwater resources could occur if proper cementing and casing programs are not followed. This could include loss of well integrity, surface spills, or loss of fluids in the drilling and completion process. It is possible for chemical additives used in drilling activities to be introduced into the water-producing formations without proper casing and cementing of the well bore. Changes in porosity or other properties of the rock being drilled through can result in the loss of drilling fluids. When this occurs, drilling fluids can be introduced into groundwater without proper cementing and casing. Site specific conditions and drilling practices determine the probability of this occurrence and determine the groundwater resources that could be impacted. In addition to changing the producing formations' physical properties by increasing the flow of water, gas, and/or oil around the well bore, hydraulic fracturing can also introduce chemical additives into the producing formations. Types of chemical additives used in drilling activities may include acids, hydrocarbons, thickening agents, lubricants, and other additives that are operator- and location-specific. These additives are not always used in these drilling activities and some are likely to be benign such as bentonite clay and sand. Concentrations of these additives also vary considerably since different mixtures can be used for different purposes in oil and gas development and even in the same well bore. If contamination of aquifers from any source occurs, changes in groundwater quality could impact springs and residential wells that are sourced from the affected aquifers. Onshore Order #2 requires that the proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones.

Known water bearing zones in the lease area are protected by drilling requirements and, with proper practices, contamination of ground water resources is highly unlikely. Casing along with cement is extended well beyond fresh-water zones to insure that drilling fluids remain within the well bore and do not enter groundwater.

Potential impacts to ground water at site specific locations are analyzed through the NEPA review process at the development stage when the APD is submitted. This process includes geologic and engineering reviews to ensure that cementing and casing programs are adequate to protect all downhole resources.

All water used would have to comply with Montana State water rights regulations and a source of water would need to be secured by industry that would not harm senior water rights holders.

4.3.5.2 Mitigation

Stipulations addressing steep slopes, waterbodies, streams, 100-year floodplains of major rivers, and riparian areas would minimize potential impacts and would be included with the lease when necessary (Appendix A). In the event of exploration or development, measures would be taken to reduce, avoid, or minimize potential impacts to water resources including application of appropriate mitigation. Mitigation measures that minimize the total area of disturbance, control wind and water erosion, reduce soil compaction, maintain vegetative cover, control nonnative species, and expedite rapid reclamation (including interim reclamation) would maintain water resources.

Methods to reduce erosion and sedimentation could include reducing the area of surface disturbance; installing and maintaining adequate erosion control; proper road design, road surfacing, and culvert design; road/infrastructure maintenance; use of low water crossings; and use of isolated or bore crossing methods for waterbodies and floodplains. In addition, applying mitigation to maintain adequate, undisturbed, vegetated buffer zones around waterbodies and floodplains could reduce sedimentation and maintain water quality. Appropriate well completion, the implementation of Spill Prevention Plans, and Underground Injection Control regulations would mitigate groundwater impacts. Site-specific mitigation and reclamation measures would be described in the COAs.

4.3.6 Vegetation Resources

4.3.6.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on vegetation resources. Any potential effects from sale of lease parcels could occur at the time the leases are developed.

Impacts to vegetation depend on the vegetation type/community, soil community and the topography of the lease parcels. Disturbance to vegetation is of concern because protection of soil resources, maintenance of water quality, conservation of wildlife habitat, and livestock production capabilities could be diminished or lost over the long-term through direct loss of vegetation (including direct loss of both plant communities and specific plant species).

Other direct impacts, such as invasive species invasion, could result in loss of desirable vegetation. Invasive species and noxious weeds could also reduce livestock grazing forage, wildlife habitat quality, and native species diversity. In addition, invasive species are well known for changing fire regimes.

Additionally, surface disturbing activities directly affect vegetation by destroying habitat, churning soils, impacting biological crusts, disrupting seedbanks, burying individual plants, and generating sites for competitive species. Other vegetation impacts could also be caused from soil erosion and result in loss of the supporting substrate for plants, or from soil compaction resulting in reduced germination rates. Impacts to plants occurring after seed germination but prior to seed set could be particularly harmful as both current and future generations would be affected.

Fugitive dust generated by construction activities and travel along dirt roads could affect nearby plants by depressing photosynthesis, disrupting pollination, and reducing reproductive success. Oil, fuel, wastewater or other chemical spills could contaminate soils as to render them

temporarily unsuitable for plant growth until cleanup measures were fully implemented. If cleanup measures were less successful, longer term vegetation damage could be expected.

Oil and gas development activity could reduce BLM's ability to manage livestock grazing while meeting or progressing towards meeting the Standards of Rangeland Health. Development and associated disturbances could reduce available forage or alter livestock distribution leading to overgrazing or other localized excess grazing impacts. Construction of roads, especially in areas of rough topography could cause significant changes in livestock movement and fragment suitable habitat for some plant communities.

4.3.6.2 Mitigation

Mitigation would be addressed at the site specific APD stage of exploration and development. If needed, COAs would potentially include, but not limited to, revegetation with desirable plant species, soil enhancement practices, direct live haul of soil material for seed bank revegetation, reduction of livestock grazing, fencing of reclaimed areas, and the use of seeding strategies consisting of native grasses, forbs, and shrubs. In areas infested with noxious weeds, weed management plans with special conditions would be required.

4.3.7 Riparian-Wetland Habitats

4.3.7.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on riparian-wetland habitats. Any potential effects from sale of lease parcels could occur at the time the leases are developed.

The exploration and development of oil and gas within uplands or adjacent to riparian-wetland areas could reduce riparian-wetland functionality by changing native plant productivity, composition, richness, and diversity; accelerating erosion; increasing sedimentation; and changing hydrologic characteristics. Impacts that reduce the functioning condition of riparian and wetland areas could impair the ability of riparian/wetland areas to reduce nonpoint source pollution (MDEQ 2012) and provide other ecosystem benefits. The magnitude of these effects would be dependent on the specific activity, season, proximity to riparian-wetland areas, location in the watershed, upland and riparian-wetland vegetation condition, mitigation applied, and the time until reclamation success. Increases in erosion are typically localized, short term, and occur from the beginning of implementation through vegetation reestablishment. As acres of surface disturbance increase within a watershed, so could the effects on riparian-wetland resources.

4.3.7.2 Mitigation

Stipulations addressing steep slopes, waterbodies, streams, 100-year floodplains of major rivers, and riparian areas would minimize potential impacts and would be included with the lease when necessary (Appendix A). In the event of exploration or development, site-specific mitigation measures would be identified which would avoid or minimize potential impacts to riparian-wetland areas at the APD stage. Mitigation measures that minimize the total area of disturbance, control wind and water erosion, reduce soil compaction, maintain vegetative cover, control nonnative species, maintain biodiversity, maintain vegetated buffer zones, and expedite rapid reclamation (including interim reclamation) would maintain riparian-wetland resources.

4.3.8 Special Status Plant Species

4.3.8.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on special status plant species. Any potential effects from the sale of leases could occur at the time the leases are developed.

4.3.8.2 Mitigation

Stipulations applied to wildlife resources, steep slopes, waterbodies, streams, 100-year floodplains of major rivers, riparian areas, and wetlands would likely also provide protections for special status plant species. Proposed development would be analyzed on a site-specific basis prior to approval of oil and gas exploration or development activities at the APD stage. Mitigation would also be addressed at the site-specific APD stage. Surveys to determine the existence of federally listed species could occur on BLM-administered surface or minerals prior to approval of exploration and development activities at the APD stage.

4.3.9 Wildlife

4.3.9.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on wildlife. Any potential effects from the sale of lease parcels would occur at the time the leases are developed.

The use of standard lease terms and stipulations on these lands (Appendix A) would minimize, but not preclude impacts to wildlife. Oil and gas development which results in surface disturbance could directly and indirectly impact aquatic and terrestrial wildlife species. These impacts would include loss or reduction in suitability of habitat, improved habitat for undesirable (non-native) competitors, species or community shift to species or communities more tolerant of disturbances, nest abandonment, mortalities resulting from collisions with vehicles and power lines, electrocutions from power lines, barriers to species migration, habitat fragmentation, increased predation, habitat avoidance, and displacement of wildlife species resulting from human presence. The scale, location, and pace of development, combined with implementation of mitigation measures and the tolerance of the specific species to human disturbance all influence the severity of impacts to wildlife species and habitats, including threatened, endangered, candidate, proposed, and other special status species.

4.3.9.1.1 Threatened, Endangered, and Candidate Species

Habitat within the lease parcels exists to support USFWS threatened, endangered, or candidate, species including the whooping crane, pallid sturgeon, sage grouse, and Sprague's pipit.

The BLM has determined that the act of issuing leases within the whooping crane migration corridor will not affect the whooping crane. However, impacts to whooping cranes are possible from subsequent oil and gas development activities permitted at the APD stage. At this time, stipulations do not currently exist to protect any known whooping crane migration staging areas. Line strikes, collisions with vehicles, habitat fragmentation, and other anthropogenic activities could disturb, displace, or cause direct mortality of whooping cranes.

Therefore, if development on any of the leases within the whooping crane migration corridor is proposed within suitable whooping crane staging, stopover or roosting habitat, BLM would consult with the USFWS pursuant to section 7(a)(2) of ESA. An outcome of the consultation

process could be that conditions of approval are attached to the permit or the permit could not be approved. Other BMP's could also be developed through consultation, including minimizing disturbance, adherence to Avian Powerline Interaction Committee (APLIC) guidelines, and others as deemed appropriate.

Pallid sturgeon individuals and their habitat would occur in or near lease parcel MTM 105431-H6, H8, HA, and HB (based on year-round range and observation maps (MTNHP)) and have the potential to be affected by the development of oil and gas wells. Potential impacts from development could include: overland oil spills, underground spills from activities associated with horizontal drilling or other practices, spills from drilling mud or other extraction and processing chemicals, and surface disturbance activities that create a localized erosion zone. Oil spills and other pollutants from the oil extraction process could harm the endangered pallid sturgeon in two different ways. First, toxicological impacts from direct contact could have immediate lethal effects to eggs, juveniles, and adults. Second, toxic effects to lower food web levels (e.g. aquatic macro-invertebrates) could indirectly affect the pallid sturgeon species by degrading water quality and degrading or eliminating food resources. Additionally, surface disturbing activities that decrease the availability or input of organic material, large woody debris, and trees could decrease cover, food-web compartments and fluxes, and holding areas for pallid sturgeon. Other aquatic species could experience the same type of direct and indirect impacts.

Currently, in the Big Dry RMP there are no stipulations specific to Pallid sturgeon habitat. However, a floodplain stipulation (NSO 11-2) would not allow surface occupancy in the 100-year floodplain boundary of the Missouri and Yellowstone Rivers

The BLM has determined that issuing a lease for the four parcels along the Missouri River will have no effect on the pallid sturgeon. If development were to occur, additional mitigation would be included as conditions of approval at the APD stage. These conditions include the placement of earthen berms and oil skimmers (a culvert device placed in drainages which is intended to block oil from entering streams) to help protect pallid sturgeon habitat in case of oil spills by greatly reducing the potential for spills to reach pallid sturgeon habitat. If oil and gas development is proposed for these four parcels, BLM would consult with the USFWS pursuant to section 7(a)(2) of ESA.

Sage grouse are offered species specific protections through a stipulation. Under Alternative B, ¼ mile NSO buffers and 2 mile timing buffers would apply where relevant. Based on research, these stipulations for sage grouse are considered ineffective to ensure that sage grouse can persist within fully developed areas. With regard to existing restrictive stipulations applied by the BLM, (Walker et al. 2007a) research has demonstrated that the 0.4-km (0.25 miles) NSO lease stipulation is insufficient to conserve breeding sage-grouse populations in fully developed gas fields because this buffer distance leaves 98 percent of the landscape within 3.2 km (2 miles) open to full-scale development. Full-field development of 98 percent of the landscape within 3.2 km (2 miles) of leks in a typical landscape in the Powder River Basin reduced the average probability of lek persistence from 87 percent to 5 percent (Walker et al. 2007a).

Other studies also have assessed the efficacy of existing BLM stipulations for sage grouse. Impacts to leks from energy development are most severe near the lek, and remained discernable out to distances more than 6 km (3.6 miles) (Holloran 2005, Walker et al. 2007a), and have

resulted in the extirpation of leks within gas fields (Holloran 2005, Walker et al. 2007a). Holloran (2005) shows that lek counts decreased with distance to the nearest active drilling rig, producing well, or main haul road, and that development influence counts of displaying males to a distance of between 4.7 and 6.2 km (2.9 and 3.9 miles). All well-supported models in Walker et al. (2007a) indicate a strong effect of energy development, estimated as proportion of development within either 0.8 km (0.5 miles) or 3.2 km (2 miles), on lek persistence. Buffer sizes of 0.25 mi., 0.5 mi., 0.6 mi. and 1.0 mi. result in an estimated lek persistence of 5 percent, 11 percent, 14 percent, and 30 percent. Lek persistence in the absence of CBNG development averages approximately 85 percent. Models with development at 6.4 km (4 miles) had considerably less support, but the regression coefficient indicated that impacts were still apparent out to 6.4 km (4 miles) (Walker et al. 2007a). Tack (2009) found impacts of energy development on lek abundances (numbers of males per lek) out to 7.6 miles.

The 2 mile timing stipulation attached to the respective parcels in this proposal only applies between March 1 to June 15, and development can occur within the 2 miles outside of those dates. Not all lease parcels would be expected to see full field development as noted in the range of RFD, although effects would most likely mirror these studies to some degree proportionate to the amount of development that occurs outside of the stipulated timeframe.

Noise has been shown to affect sage-grouse and associated sagebrush obligates. Sage-grouse are known to select highly visible leks with good acoustic properties. Effects to sage-grouse would be a decrease in numbers of males on leks and activity levels and lower nest initiation near oil and gas development. Sage-grouse numbers on leks within 1.6 km (1 mile) of coal bed natural gas compressor stations in Campbell County, Wyoming were shown to be consistently lower than on leks not affected by this disturbance (Braun et al. 2002). Holloran (2005), Holloran et al. (2005a, 2005b), and Anderson (2005) reported that lek activity by sage-grouse decreased downwind of drilling activities, suggesting that noise had measurable negative impacts on sage-grouse. The actual level of noise (measured in decibels) that would not affect greater sage-grouse breeding and nesting activities is presently unknown. Timing restriction (TL 13-3) is applied within 2 miles of leks within the MCFO, which provides some mitigation for noise level effects to sage-grouse during this timeframe.

Recent inventories for sage grouse leks have not been conducted within some of the parcels. Therefore, inventories would be conducted at the APD stage of development to determine the presence or absence of sage grouse leks. This alternative also includes the attachment of a sage grouse lease notice (LN 14-11) when the lease parcel is located within 2 miles of a lek. The lease notice would require an operator to implement specific measures to reduce impacts of oil and gas operations on sage grouse populations and habitat quality. The application of this lease notice would be expected to reduce, but not eliminate, impacts to sage grouse and habitats.

Energy development (oil, gas, and wind) and associated roads and facilities increase the fragmentation of grassland habitat. A number of studies have found that Sprague's pipits appear to avoid non-grassland features in the landscape, including roads, trails, oil wells, croplands, woody vegetation, and wetlands (Dale et al. 2009, pp. 194, 200; Koper et al. 2009, pp. 1287, 1293, 1294, 1296; Greer 2009, p. 65; Linnen 2008, pp. 1, 9-11, 15; Sutter et al. 2000, pp. 112-114). Sprague's pipits avoid oil wells, staying up to 350 meters (m) (1148 feet (ft.)) away

(Linnen 2008, pp. 1, 9-11), magnifying the effect of the well feature itself. Oil and gas wells, especially at high densities, decrease the amount of habitat available for breeding territories. (Federal Register: September 15, 2010 (Volume 75, Number 178))

Potential suitable habitat exists for the Sprague's pipit across some of the proposed lease parcels; however, inventories have not been conducted within the parcels. Therefore, inventories would be conducted at the APD stage of development to determine the presence or absence of Sprague's pipits. The Sprague's pipit lease notice, LN 14-15, is issued with those leases and would be applied if Sprague's pipits are found in the area. If Sprague's pipits are found, protective measures would be applied as conditions of approval to minimize impacts to Sprague's pipits and their habitat. In the event oil and gas development is proposed within Sprague's pipit habitat, at the APD stage BLM would conference with the USFWS pursuant to section 7(a)(4) of ESA, or if the Sprague's pipit has been listed as threatened or endangered, BLM would consult with the USFWS pursuant to section 7(a)(2).

4.3.9.1.2 Other Special Status Species

As noted, up to 51 wildlife species that BLM has designated as "sensitive" have the potential to occur within the parcel areas. Stipulations are not provided for all BLM sensitive species in the current RMPs. Stipulations are provided for 7 out of the 46 "non-TE&P" sensitive species. For those species afforded some protections through existing stipulations, impacts could be minimized, but not eliminated. Impacts to BLM sensitive species would be similar to those described above, unless they are afforded protective measures from other regulations such as the Migratory Bird Treaty Act (MBTA) (16 U.S.C. 703.) or the Bald and Golden Eagle Protection Act (BGEPA) (16 U.S.C. 668-668c). The BLM does not consult with the USFWS on "sensitive" species and likewise would not receive terms and conditions from USFWS requiring additional protections of those species.

Numerous species of birds were identified as potential inhabitants across the analysis area. With the impacts associated with development, it is reasonable to assume there would be impacts to nesting and migrating bird species. The primary impacts to these species would include disturbance of preferred nesting habitats, improved habitat for undesirable competitors and/or a species shift to disturbance associated species, and increased vehicle collisions.

Research in Sublette County, Wyoming on the effects of natural gas development on sagebrush steppe passerines documented negative impacts to sagebrush obligates such as Brewer's sparrows, sage sparrows, and sage thrashers (Ingelfinger 2001). The impacts were reported greatest along roads where traffic volumes are high and within 100 meters of these roads. Sagebrush obligates were reduced within these areas by as much as 60%. Sagebrush obligate density was reduced by 50% within 100 meters of a road even when traffic volumes were less than 12 vehicles /day. It would be expected that similar population declines would occur to other native prairie species within the analysis area.

Stipulations do not exist specifically for the protection of BLM sensitive songbirds. The MBTA prohibits the take, capture or kill of any migratory bird, any part, nest or eggs of any such bird (16 U.S.C 703 (a)). NEPA analysis pursuant to Executive Order 13186 (January 2001) requires BLM to ensure that MBTA compliance and the effects of Bureau actions and agency plans on

migratory birds are evaluated, should reduce take of migratory birds and contribute to their conservation.

Effects to migratory birds from oil and gas development at the APD stage could include direct loss of habitat from roads, well pads and other infrastructure, disturbance, powerline strikes and unintended direct mortality, fragmentation of habitat, change in use of habitats, and potential threats and competition from edge species. Field surveys for nesting birds at proposed development sites would be conducted for activities planned in between April 15 and July 15. Mitigation measures would be assigned at the APD stage to minimize negative effects on migratory bird populations, in compliance with Executive Order 13186 and MBTA. These mitigation measures would be required as COAs. An NSO stipulation for oil and gas surface disturbing activities in riparian and wetland areas would prohibit any potential oil and gas development in those habitats unless approval was granted through the Waivers, Exceptions, and Modifications (WEM) process. The BLM would coordinate WEMs with USFWS to assure MBTA compliance.

Take of bald and golden eagles and any other migratory raptors would not occur as a result of the act of leasing parcels. However, as development occurs after permits to drill are issued, there would be potential for take to occur as a result of raptor collisions with vehicles, power lines, and other development-related actions. Therefore, field surveys for raptors at proposed development sites would be conducted for activities planned between March 1 and August 1. To comply with MBTA and BGEPA, BLM would require protective measures and stipulations at the APD stage to prevent or minimize impacts to individual raptors and raptor populations, including bald and golden eagles. The protective measures would be required as COAs.

4.3.9.1.3 Other Fish and Wildlife

The types and extent of impacts to other wildlife species and habitats from development are similar to those described above for other species. Based on the RFD scenarios, direct habitat loss is possible. Initial disturbance could change the occupation of those areas to disturbance-oriented species (e.g., horned larks), or species with more tolerance for disturbances. These changes could also be expected to decrease the diversity of wildlife. Although bladed corridors would be reclaimed after the facilities are constructed, some changes in vegetation could occur along the reclaimed areas. The goal of reclamation is to restore disturbed areas to pre-disturbed conditions. The outcome of reclamation, unlike site restoration, will therefore not always mimic pre-disturbance conditions and offer the same habitat values to wildlife species. Sagebrush obligates, including some species of songbirds and sage grouse, could be most affected by this change.

It is anticipated that some development could occur adjacent to existing disturbances of some type. Depending on proximity and species tolerance, wildlife species within these areas could either have acclimated to the surrounding conditions, previously been displaced by construction activities, or could be caused to be displaced to other areas with or without preferred habitat.

Potential impacts to aquatic wildlife from development could include: overland oil spills, underground spills from activities associated with horizontal drilling or other practices, spills from drilling mud or other extraction and processing chemicals, and surface disturbance

activities that create a localized erosion zone. Oil spills and other pollutants from the oil extraction process could harm the aquatic wildlife species in two different ways if the spill substances enter the habitat. First, toxicological impacts from direct contact could have immediate lethal effects to eggs, larvae, juveniles, and adults. Second, toxic effects to lower food web levels (e.g. aquatic macro-invertebrates) could indirectly affect fish, amphibian, and reptile species by degrading water quality and degrading or eliminating food resources.

Additional mitigation could occur as COAs at the APD stage. These conditions could include the placement of earthen berms and oil skimmers (in ephemeral drainages where fish passage will not be blocked) to help protect aquatic wildlife habitat in case of oil spills.

Oil and gas development is allowed within big game crucial winter range with a timing restriction from December 1 to March 31. This stipulation does not apply to operation and maintenance of production facilities. The goal of this stipulation is to protect crucial big game habitats from disturbance during the winter use season. This stipulation provides protection to big game winter habitats and species only during that timeframe, and does not provide protection during the long-term operation and maintenance periods. Development can occur outside of those dates and will exist thereafter until reclamation, thus only delaying impacts until after that year of construction.

Mule deer could be impacted by this project from habitat fragmentation and disturbance. Mule deer winter range habitat has been identified within 6 lease parcels. Development could affect mule deer use of winter range habitat in those areas. Studies conducted in the Pinedale anticline of Wyoming found that mule deer avoided areas in close proximity to well pads with no evidence of well-pad acclimation during 3 out of 4 years. During year 4 of development habitat selection patterns were influenced more by road density, and not proximity of well pads. The authors attributed this to an unusually severe winter, where movement options and available habitat was limited. Densities of mule deer decreased by an estimated 46% within the developed area over the four years, and indirect impacts were observed out to 2.7-3.7 km of well sites. Mule deer distribution shifted toward less preferred and presumably less suitable habitat. (Sawyer et al. 2005) Similar impacts could be expected from development with this proposal.

White-tailed deer could also be expected to be impacted by this project from habitat fragmentation and disturbance. Winter range for white-tailed deer exists across the analysis area, but covers much less area than other big game ranges. White-tailed deer winter range has been identified within 1 lease parcel.

Pronghorn could be impacted by this project from habitat fragmentation and disturbance. Pronghorn winter range habitat has been identified within 9 lease parcels. Preliminary studies in the upper green river basin in Wyoming report that some pronghorn exhibit movement patterns that suggest almost complete avoidance of gas field areas of intensive development in the Jonah field during the winter, whereas pronghorn in the Pinedale Anticline Project Area (PAPA) apparently have not been avoiding human activities. It is speculated that the difference may exist due to different levels in well densities, as the Jonah field was reported as 1 well/57 acres, and the PAPA at 1 well/124 acres (Berger et al. 2007). Effects to winter range within existing and

future oil and gas development and exploration would be similar to those referenced above and could depend on rate and location of development.

Sharp-tailed grouse dancing grounds exist on 2 proposed lease parcels, and ¼ mile NSO buffers are applied to these parcels. In addition, all or portions of 10 lease parcels are located within 2 miles of sharp-tailed grouse leks where timing stipulations from March 1 to June 15 were applied. This timing does not apply to operation and maintenance of production facilities. Recent inventories for sharp-tailed grouse dancing grounds have not been conducted within some of the parcels. Therefore, inventories would be conducted at the APD stage of development to determine the presence or absence of sharp-tailed grouse dancing grounds. Although limited research exists that documents impacts to sharp-tailed grouse from development activities, it is expected that sharp-tailed grouse could be impacted by this project from habitat fragmentation and disturbance. Vehicles and human activity during breeding and nesting seasons could reduce breeding activity, displace nesting hens and reduce the suitability of habitat for brood-rearing. Mortality could increase as a result of collisions with vehicles.

Wild turkeys, pheasants, and Hungarian partridge could also be affected by disturbance and direct mortality through nest destruction and vehicle collisions during the development stages.

4.3.9.2 Mitigation

Measures would be taken to prevent, minimize, or mitigate impacts to fish and wildlife animal species from exploration and development activities. Prior to authorization, activities would be evaluated on a case-by-case basis, and the project would be subject to mitigation measures. Mitigation could include rapid revegetation, project relocation, or pre-disturbance wildlife species surveying. If oil and gas development is proposed in suitable habitat for threatened or endangered species, consultation with the USFWS would occur to determine if additional terms and conditions would need to be applied.

4.3.10 Cultural Resources

4.3.10.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on cultural resources. Any potential effects from the sale of leases would occur at the time the leases are developed.

Potential effects from surface disturbance associated with exploration and development activities have the potential to alter the characteristics of a significant cultural or historic property by diminishing the integrity of the property's location, design, setting, materials, workmanship, feeling, or association. Other effects to cultural resources from proposed surface disturbance activities include the destruction, damage, or alteration to all or part of the cultural resource and diminishing the property's significant historic features as a result of the introduction of visual, atmospheric, or audible elements. Cultural resource investigations associated with development potentially adds to our understanding of the prehistory/history of the area and discovery of sites that would otherwise remain undiscovered due to burial or omission. Indirect effects to cultural resources within the analysis area by county are as follows:

The following lease parcels have sites within their boundaries: MTM 105431-H9- within Roosevelt County.

One lease parcel (MTM 105431-HA) is located in McCone County consisting of 40.0 acres. Based on modeling, the parcel might contain less than one cultural site (.43 sites) of which less than one could have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Ten lease parcels (MTM 105431-HC, HD, HE, HG, HH, HJ, HF, HK, HL and HM) are located in Powder River County consisting of 4,597 acres (4596.87 acres). Based on modeling, the parcels might contain up to 49.4 cultural sites of which 5 to 8 could have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Two lease parcels (MTM 102757-WT and WW) are located in Prairie County consisting of 1,919 acres (1,919.24 acres). Based on modeling, the parcels might contain up to 20.6 cultural sites of which two to three could have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Three lease parcels (MTM 105431-HB, H6 and H8) are located in Richland County consisting of 1,189 acres (1,189.21 acres). Based on modeling, the parcels might contain up to 13 cultural sites (12.7) of which one to two could have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Two lease parcels (MTM 105431-H9 and JA) are located in Roosevelt County consisting of 200 acres (199.96 acres). Based on modeling, the parcels might contain 2 cultural sites of which less than one could have potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Leasing approximately 7,945 acres of Federal minerals within the five counties described above could indirectly affect 85.4 cultural sites based upon modeling (Aaberg et al 2006). Of the modeled 85 cultural sites, 8 to 13 sites may have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

The Reasonable Foreseeable Development (RFD and Appendix D) scenario for the lease parcels predicts 7 wells and 29.4 acres of disturbance as a result from leasing the parcels which may affect 1 site which may have the potential to be eligible for listing on the National Register of Historic Places.

4.3.10.2 Mitigation

Application of standard lease terms, stipulations, and cultural lease notices provide mechanisms to protect vulnerable significant cultural resource values on these lease parcels (Appendix A). Lease notice LN 14-2 would be applied to 1 lease parcel (MTM 105431-H9). Lease notice LN 14-14 would be applied to 3 lease parcels (MTM 105431-H8, H9 and HB). The cultural resource lease stipulation CR16-1 would be applied to all the lease parcels. The inclusion of these requirements at the leasing stage provide notification to the lessee that potentially valuable cultural resources are or are likely to be present on the lease parcels and potential mitigation measures may be required. The application and implementation of these stipulations and lease

notices at the development stage would provide the necessary measures to protect cultural resources.

Specific mitigation measures, include but are not limited to, site avoidance, excavation or data recovery would have to be determined when site-specific development proposals are received. Most surface-disturbing situations for cultural resources would be avoided by project redesign or relocation. Unavoidable, significant properties would be site-specifically mitigated with concurrence with the State Historic Preservation Office prior to implementation of a project.

4.3.11 Native American Religious Concerns

4.3.11.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on Native American religious concerns. Any potential effects from the sale of leases could occur at the time the leases are developed.

Leasing parcels located near the Fort Peck Reservation in Richland and Roosevelt Counties and Turtle Mountain Public Domain Allotments in Roosevelt County would not interfere with the performance of traditional ceremonies and rituals pursuant to the American Indian Religious Freedom Act (AIRFA) or EO 13007. Leasing parcels in this area would not prevent tribes from visiting sacred sites or prevent possession of sacred objects.

4.3.11.2 Mitigation

Mitigation would be the same as section 4.3.10.2 above. For those parcels where no inventory data is available or where no information is available for TCPs, BLM would apply the cultural lease notice (CR 16-1). The sites in parcel MTM 105431-H9 would be revisited and reevaluated for National Register eligibility prior to any surface disturbance.

4.3.12 Paleontology

4.3.12.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on paleontological resources. Any potential effects from the sale of leases could occur at the time the leases are developed.

Indirect impacts from the sale of leases would be from the surface disturbances associated with oil and gas exploration and development activities. It is anticipated that most significant fossil resources are located in those geologic units with a Potential Fossil Yield Classification (PFYC) of 3 or higher. However, significant fossil resources could be discovered anywhere. Surface-disturbing activities could potentially alter the characteristics of paleontological resources through damage, fossil destruction, or disturbance of the stratigraphic context in which paleontological resources are located, resulting in the loss of important scientific data. Identified paleontological resources could be avoided by project redesign or relocation before project approval which would negate the need for the implementation of mitigation measures. Conversely, surface-disturbing activities could potentially lead to the discovery of paleontological localities that would otherwise remain undiscovered due to burial or omission during review inventories. The scientific retrieval and study of these newly discovered resources would expand our understanding of past life and environments of Montana.

4.3.12.2 Mitigation

The application of lease terms, the paleontological no surface occupancy stipulation (NSO 11-12), and the paleontological lease notices (LN 14-3 and LN 14-12) at leasing, provides protection to paleontological resources during development. The paleontological lease notice LN 14-12 is applied to those lease parcels that fall within geological units with a PFYC Class of 3 or higher, usually requiring a field survey prior to surface disturbance. These inventory requirements could result in the identification of paleontological resources. Avoidance of significant paleontological resources or implementation of mitigation prior to surface disturbance would protect paleontological resources. However, the application of lease terms only allows the relocation of activities up to 200 meters, unless documented in the NEPA document, and cannot result in moving the activity off lease.

Specific mitigation measures could include, but are not limited to, site avoidance or excavation. Avoidance of paleontological properties would be a best management practice. However, should a paleontological locality be unavoidable, significant fossil resources must be mitigated prior to implementation of a project. Also, significant fossil resources could be discovered in areas that had not been evaluated (PFYC of less than 3) during surface disturbance. Those resources must also be professionally mitigated. These mitigation measures and contingencies would be determined when site specific development proposals are received.

In order to protect paleontological resources, 18 of the parcels are recommended to have the Paleontological lease notice 14-12 applied per guidance identified in IM 2009-011 and 2008-009. No parcels are recommended for the no surface occupancy lease stipulation (NSO 11-12) based upon paleontological resources. See section 3.10 Paleontology for list of parcels.

4.3.13 Visual Resources

4.3.13.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on visual resources. Any potential effects from the sale of leases could occur at the time the leases are developed.

The lease parcels fall into VRM classes II, III and IV, as demonstrated in Section 3.11, Visual Resources, Table 7. While the act of leasing federal minerals produces no visual impacts, development of a lease parcel could result in some level of modification to the existing landscape at the time of development.

4.3.13.2 Mitigation

All new oil and gas development would implement, as appropriate for the site, BLM BMPs for VRM, regardless of the VRM class. This includes, but would not be limited to, proper site selection, reduction of visibility, minimizing disturbance, selecting color(s)/color schemes that blend with the background and reclaiming areas that are not in active use. Repetition of form, line, color and texture when designing projects would reduce contrasts between landscape and development. Wherever practical, no new development would be allowed on ridges or mountain tops. Overall, the goal would be to not reduce the visual qualities or scenic value that currently exists.

There are no lease parcels that fall within a VRM Class II management objective. Measures would be taken to mitigate the visual impacts within a Class III and Class IV area to protect the scenic value.

4.3.14 Forest and Woodland Resources

4.3.14.1 Direct and Indirect Effects

Potential impacts from oil and gas development could include the cutting and subsequent removal of forest and woodland vegetation from drill-site development areas; including roads, pads, surface facilities, pipelines, and power-lines. The degree of impact would vary according to the precise location of development activities in the parcel area and is directly related to topography, miles of road construction, standing timber volume per acre, and total acres of surface facilities development. A total of approximately 2,116 forest and woodland acres could potentially be impacted under this alternative; 1,671 acres of evergreen, 361 acres of deciduous, and 84 acres of mixed evergreen-deciduous forest.

4.3.14.2 Mitigation

Measures would be taken to prevent, minimize, or mitigate impacts to forest and woodland resources from exploration and development activities. Prior to authorization, activities would be evaluated on a case-by-case basis, and the project would be subject to mitigation measures. The road construction and maintenance BMPs outlined in the Gold Book are consistent with the Water Quality BMPs for Montana Forests (Logan 2001) which are designed to protect water quality and forest soils. Other mitigation measures could include the artificial planting of bareroot or containerized nursery stock seedlings.

All severed forest and woodland vegetative material would need to be removed or reduced to acceptable standards meeting Montana's Control of Timber Slash and Debris Law (Title 76, Chapter 13, Part 4), commonly referred to as the "Slash" Law; therefore, requiring burning, grinding, chipping, burying, or hauling residual debris off-site to a designated landfill or other location for disposal.

4.3.15 Livestock Grazing

4.3.15.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on livestock grazing. Any potential effects from the sale of leases would occur at the time the leases are developed.

Oil and gas development could result in a loss of vegetation for livestock grazing (e.g., direct removal, introduction of unpalatable plant species, etc.), decrease the palatability of vegetation due to fugitive dust, disrupt livestock management practices, involve vehicle collisions, and decrease grazing capacity. Direct losses of forage could also result from construction of roads, well pads and associated infrastructure and would vary depending on the extent of development. These impacts could vary from short-term impacts to long-term impacts depending on the type of exploration or development, the success of reclamation, and the type of vegetation removed for the oil and gas activities.

If development activity is reducing vegetative resources for livestock grazing and the grazing activity is resulting in the allotment not meeting the standards for rangeland health, then the

authorized officer would have to take action prior to the next grazing season to ensure the BLM lands are progressing towards meeting the standards. This could result in the change of livestock grazing activities in order to improve vegetative conditions.

4.3.15.2 Mitigation

Measures would be taken to prevent, minimize, or mitigate impacts to livestock grazing from exploration and development activities. Prior to authorization, activities would be evaluated on a case-by-case basis, and the project would be subject to mitigation measures. Mitigation could potentially include controlling livestock movement by maintaining fence line integrity, fencing of facilities, re-vegetation of disturbed sites, and fugitive dust control.

4.3.16 Recreation and Travel Management

4.3.16.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on recreation and travel management. Any potential effects from the sale of leases could occur at the time the leases are developed.

Recreation indirect effects could exist where oil and gas development and recreational user conflicts could occur. More specifically, in areas of high oil and gas development potential, there could be user conflicts between motorized recreationists (OHV activities), hunting, target shooting, camping, fishing, river use, picnicking, and winter activities (e.g., snowmobiling) and associated oil and gas activities. These impacts could exist in both the short-term (exploration and construction phases of oil and gas development) and in the long-term (producing wells, maintenance of facilities, etc.). Oil and gas wells, equipment, and facilities could affect the general solitude (space and noise) and scenic value of the area.

Areas frequented by recreationists, where there is other land use activities occurring, in addition to oil and gas development, the public could perceive these areas as inaccessible or unavailable because of the existing facilities. As oil and gas development occurs, new routes are created which often attract recreationists seeking additional or new areas to explore for motorized recreational opportunities. Motorized recreational opportunities could be enhanced through the additional opportunities to explore; however, user conflicts and public safety issues could result from the use of the new travel routes. The creation of routes from oil and gas activities could lead to a proliferation of user-created motorized routes, resulting in adverse impacts to the scenic qualities of the area and increased level of surface disturbance.

For those areas with isolated tracks of BLM public lands that generally do not have existing public access, recreation opportunities that occur in these areas are limited to use with adjacent land owner permission or hunting by an outfitter; therefore, oil and gas activities would have little or no impact on recreational experiences in these isolated tracks.

Foreseeable changes in recreation use levels would be an increase on the demand for recreational use of public land. Increases could be expected in, but not limited to, hunting, fishing, hiking, camping, wildlife viewing, and dispersed recreational uses. This could increase the incidence of conflict between recreationists involved in motorized activities and non-motorized activities.

4.3.16.2 Mitigation

Additional measures would be taken to minimize, avoid, or mitigate impacts to recreation from oil and gas exploration and development activities. Prior to authorization, activities would be evaluated on a case-by-case basis, and the project would be subject to mitigation measures. Mitigation measures could potentially include, but are not limited to, reclamation of industrial routes/areas when no longer needed, fencing of facilities, and installing signs along roads.

4.3.17 Lands and Realty

4.3.17.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on lands and realty. Any potential effects from the sale of leases could occur at the time the leases are developed.

Under this alternative 18 parcels that include 7,945.28 surveyed surface acres of which 3,637.97 surveyed acres are BLM administered surface and 4,307.31 surveyed acres are Non-Federal surface would be offered for lease.

Facilities associated with oil and gas development could cause disturbance to the existing rights-of-way (ROWs). There are four existing ROWs located on the following three lease parcels; MTM-102757-WT, MTM-105431-HB and MTM-105431-H8. A ROW for a county road (MTM-99365) on MTM-102757-WT, a ROW for an overhead power line (MTM-55529) on MTM-105431-H6, and a ROW for an oil and gas road (MTM-103251) and oil pipeline (MTM-103965) on MTM-105431-H8. Additional ROWs could be required across Federal surface for “off-lease” or third party facilities required for potential development of the parcels.

4.3.17.2 Mitigation

Measures would be taken to avoid disturbance to or impacts to existing rights-of-way, in the event of any oil and gas exploration and development activities. Any new “off-lease” or third party rights-of-way required across federal surface for exploration and/or development of the 18 parcels would be subject to lands and realty stipulations to protect other resources as determined by environmental analyses. In order to protect the existing rights-of-way it is recommended that LN 14-1 be applied to lease parcels MTM-102757-WT, MTM-105431-HB and MTM-105431-H8.

4.3.18 Minerals

4.3.18.1 Fluid Minerals

4.3.18.1.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on fluid minerals. Any potential effects from the sale of leases could occur at the time the leases are developed.

Issuing a lease provides opportunities to explore for and develop oil and gas resources; however, exploration and development activities must be conducted in accordance with an approved APD. Additional natural gas or crude oil produced from any or all of the 18 parcels in Alternative B would enter the public markets. Additional subsurface information would be obtained from drilling wells. Royalties and taxes could accrue to the Federal and State treasuries from the lease parcel lands.

Under Alternative B, all of the lease parcels would be offered for lease subject to major (NSO) or moderate (CSU) constraints and/or standard lease terms and conditions.

Stipulations applied to various areas with respect to occupancy, timing limitation, and control of surface use could affect oil and gas exploration and development, both on and off the Federal lease parcel. Leases issued with major constraints (NSO stipulations) could decrease some lease values, increase operating costs, and require relocation of well sites, and modification of field development. Leases issued with moderate constraints (timing limitation and controlled surface Use (CSU) stipulations) could result in similar but reduced impacts, and delays in operations and uncertainty, on the part of operators, regarding restrictions.

Hydraulic Fracturing

Hydraulic fracturing has been utilized by the oil and gas industry since the late 1940's. Within the planning area, hydraulic fracturing, in conjunction with horizontal drilling described above, has allowed for development of unconventional zones that were once considered uneconomical, like the Bakken and Three Forks Formations in the Williston Basin area.

Hydraulic fracturing is a technique used to create additional space and connecting existing fractures and existing rock pores with newly created fractures that are located in deep underground geologic formations. The induced space allows the rock to more readily release oil and natural gas so it can flow to the surface via the well bore that would otherwise be uneconomical to develop. Wells that undergo hydraulic fracturing may be drilled vertically, horizontally, or directionally and the resultant fractures induced by the hydraulic fracturing can be vertical, horizontal, or both. The typical steps of hydraulic fracturing can be described as follows:

1. Water, sand and additives are pumped at high pressures down the wellbore.
2. The liquid goes through perforated sections of the wellbore and into the surrounding formation, fracturing the rock and injecting sand or other proppants into the cracks to hold them open.
3. Experts continuously monitor and gauge pressures along with the volume of fluids and proppants, while studying how the sand reacts when it hits the bottom of the wellbore; slowly increasing the density of sand to water as the frac progresses.
4. This process may be repeated multiple times, in "stages" to reach maximum areas of the wellbore. When this is done, the wellbore is temporarily plugged between each stage to maintain the highest water pressure possible and get maximum fracturing results in the rock.
5. Frac plugs are drilled or removed from the wellbore and the well is tested for results.
6. The water pressure is reduced and fluids are returned up the wellbore for disposal or treatment and re-use, leaving the sand in place to prop open the cracks and allow the oil/gas to flow to the well bore.

Fracturing fluid is typically more than 98 percent water and sand, with small amounts of readily available chemical additives used to carry the proppant and control the chemical and mechanical properties of the water and sand mixture. Proppant, consisting of synthetic or natural silica sand, may be used in quantities of few hundred tons for a vertical well to a few thousand tons for a

horizontal well. The amount of water needed to fracture a well in the planning area depends on the geologic basin, the formation, and depth and type of well (vertical, horizontal, directional), and the proposed completion process.

Several sources of water are available for hydraulic fracturing in the planning area. The Fluid Minerals Operations and Procedures Appendix contain further details on sources of water that could potentially be used for hydraulic fracturing or drilling operations. The use of any specific water source on a federally administered well, requires the proposal be reviewed and analyzed through the NEPA process for BLM approval during the APD stage to ensure compliance with Montana water laws and federal regulations.

Before hydraulic fracturing takes place, all surface casing and some deeper, intermediate zones are required to be cemented from the bottom of the cased hole to the surface in accordance to Onshore Order #2, MBOGC rules and regulations, and API standards. The cemented well is pressure tested to ensure there are no leaks and a cement bond log is run to ensure the cement has bonded to the casing and the formation.

MBOGC regulations also ensure that all resources including groundwater are protected. The MBOGC regulations require new and existing wells, which will be stimulated by hydraulic fracturing, must demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed. If the operator proposes hydraulic fracturing through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. In accordance with MBOGC Rule 36.22.1015 operators are required to disclose and report the amount and type of fluids used in well stimulation to the Board or, if approved by the Board, to the Interstate Oil and Gas Compact Commission/Groundwater Protection Council hydraulic fracturing web site (FracFocus.org).

4.3.19 Special Designations

4.3.19.1 National Historic/Scenic Trails

There are no lease parcels located within the Lewis and Clark National Historic Scenic Trail or the Lewis and Clark Special Recreation Management Area (SRMA). However, two Lease parcels, MTM 105431-H8 and HB (947.3 acres), are located within a 3 mile sensitive Setting Consideration Zone (SCZ) around the Lewis and Clark National Historic Trail (NHT) and SRMA.

Potential effects from surface disturbances associated with exploration and development activities after leasing have the potential to alter the characteristics of the significant Lewis and Clark National Historic Trail, a cultural and historic property, by diminishing the integrity of the property's location, design, setting, materials, workmanship, feeling, or association. The effects to the Lewis and Clark National Historic Trail cultural resource from proposed surface disturbance activities include the destruction, damage, or alteration to all or part of the cultural resource and diminishing significant historic features of the property by the introduction of visual, atmospheric, or audible elements. This could alter or diminish the elements of this nationally significant site diminish the property's significance. These same concerns apply to a National Register eligible property and would diminish the property's eligibility status. Cultural resource investigations associated with development potentially adds to our understanding of the

prehistory/history of the area and discovery of sites that would otherwise remain undiscovered due to burial or omission.

4.3.19.2 Areas of Critical Environmental Concern (ACECs)

None of the 18 parcels are situated within a proposed or designated Area of Critical Environmental Concern (ACEC). There will be no affect to ACEC's through the proposed alternative.

4.3.19.3 Mitigation

Two Lease parcels, MTM 105431-H8 and HB, are located near the Lewis and Clark NHT. These parcels are on split-estate lands outside of the Lewis and Clark NHT, greater than ½ mile from the Trail centerline, and within the three mile potential viewshed of the river and Lewis and Clark NHT. For these parcels, BLM would apply its Best Management Practices similarly to those that pertain to Cultural Resource management.

Since the Lewis and Clark NHT is a congressionally designated component of the NHT system, BLM would apply the same kind of analysis that is applied to determining an effect to a property eligible for the National Register of Historic Places. That process includes determining whether an undertaking would have an adverse effect on the historic nature of the Lewis and Clark NHT by altering, directly or indirectly, any of the characteristics of the historic nature of the Lewis and Clark NHT in a manner that would diminish the integrity of the Trail's location, setting, feeling, or association. Adverse effects may include reasonably foreseeable effects caused by an undertaking that may occur later in time, be farther removed in distance or be cumulative.

Examples of adverse effects on the historic nature of the Lewis and Clark NHT include, but are not limited to change of the character of the Trail's historic nature or physical features within Trail's corridor setting that contribute to diminishing the Trail's historic significance; and the introduction of visual, atmospheric or audible elements that diminish the integrity of the Trail's historic significance. If it is determined that an undertaking within the viewshed of the Lewis and Clark NHT would have an adverse effect on the historic character of the Trail where the integrity of the setting is a contributing element of the historic character of the Trail, then surface occupancy or use and surface disturbance would be restricted.

Prior to surface disturbance, occupancy or use a mitigation plan (Plan) would need to be submitted to the BLM by the applicant as a component of the APD (BLM Form 3160-3) or Sundry Notice (BLM Form 3160-5) – Surface Use Plan of Operations. The operator may not initiate surface-disturbing activities unless the BLM authorized officer has approved the Plan or approved it with conditions. The Plan would need to demonstrate to the authorized officer's satisfaction that the infrastructure will either not be visible or will result in a weak contrast rating and would not have an adverse effect on the setting of the historic character of the Lewis and Clark NHT.

4.3.20 Social and Economic Conditions

4.3.20.1 Social

4.3.20.1.1 Direct and Indirect Effects

Leasing the parcels would have no direct impacts on social resources. Any potential effects from the sale of leases could occur at the time the leases are developed.

While the act of leasing Federal minerals itself would result in no social impact, subsequent exploration and development may generate impacts to people living near or using the area in the vicinity of the lease. Exploration, drilling or production could create an inconvenience to people living adjacent to leases due to increased traffic and traffic delays, and light, noise and visual impacts. This could be especially noticeable in rural areas where oil and gas development has not occurred previously. The amount of inconvenience would depend of the activity affected, traffic patterns within the area, noise and light levels, length of time and season these activities occur, etc. In addition, competition for housing could occur in some communities. However, residents living in areas that have been experiencing ongoing population losses may support the increased employment and population related to oil and gas development. Residents of counties where the development actually occurs would also benefit from the additional revenues to counties due to oil and gas leasing and development.

There is potential for disproportionate effects to low income or minority populations, specifically American Indian populations. Consultation with potentially affected Tribes would occur at the APD stage.

4.3.20.2 Economics

4.3.20.2.1 Direct and Indirect Effects

Under Alternative B, 18 parcels in counties would be made available for leasing at the October 2014 lease auction. The leasing of an additional 7,945 acres of BLM administered minerals in these counties would generate additional public revenue, stimulate economic activity, and boost production associated with Federal minerals. It is estimated that the leasing of all minerals nominated for the October auction would generate more than \$756,000 in one-time bonus bids and \$14,000 annually in rent revenue for the Federal government. Forty-nine percent of Federal revenue collected from public domain minerals and 25 percent of Federal revenue from acquired minerals (acquired under Bankhead Jones authority) are redistributed to the State. Montana then distributes 25 percent of public domain revenue and all of acquired mineral revenue back to the counties where the leases exist. Approximately 94 percent of federal minerals leased by the BLM within McCone, Powder River, Prairie, Richland and Roosevelt counties are public domain minerals. If these additional parcels were to be leased, an additional \$43,000 would be paid to the State of Montana and the five counties would receive an additional \$12,000 from the redistribution of federal revenue.

Once oil and gas extraction begins, annual rent payments on leased minerals stops and lessees begin to pay royalties equal to 12.5 percent of the value of production (43 CFR 3103.3.1). Royalties associated with future development of nominated minerals is estimated to generate an additional \$206,000 annually in federal oil and gas royalties. Of this new federal revenue, an estimated \$98,000 could be disbursed to the State and \$27,000 is estimated to be redistributed back to the five counties.

In addition to generating additional public revenue, leasing an additional 7,945 acres of federal minerals in McCone, Powder River, Prairie, Richland and Roosevelt counties will stimulate economic activity in the private sector of the local 8-county economy. Increased local demand for oil and gas drilling and support activities will create a ripple effect in the local economy as new employment and income opportunities in oil and gas related industries indirectly creates opportunities in nearly all other sectors of the local economy.

The total economic impact of leasing activities proposed under Alternative B is equal to direct and indirect effects of drilling activities, as well as the direct and indirect effects of additional public revenue redistributed back to the five counties. As shown in Table 14, the bonus bids, rents, royalties, and drilling and support activities associated with leasing an additional 7,945 acres of federal minerals is estimated to support 2 additional jobs and \$61,000 in labor income across the 8-county local economy (IMPLAN, 2014).

Disclosure of the direct, indirect, and cumulative effects of GHG emissions provides information on the potential economic effects of climate change including effects that could be termed the “social cost of carbon” (SCC). The EPA and other federal agencies developed a method for estimating the SCC and a range of estimated values (EPA 2014). The SCC estimates damages associated with climate change impacts to net agricultural productivity, human health, property damage, and ecosystems. Using a 3 percent average discount rate and year 2020 values, the incremental SCC is estimated to be \$46 per metric ton of annual CO₂e increase. Based on the GHG emission estimate provided in Section 4.3.3.1.2, the annual SCC associated with potential development on lease sale parcels is \$38,499 (in 2011 dollars). Estimated SCC is not directly comparable to economic contributions reported above, which recognize certain economic contributions to the local area and governmental agencies but do not include all contributions to private entities at the regional and national scale. Direct comparison of SCC to the economic contributions reported above is also not appropriate because costs associated with climate change are borne by many different entities.

4.3.21 Cumulative Impacts- Alternative B

Cumulative impacts are those impacts resulting from the incremental impact of an action when added to other past, present, and reasonably foreseeable actions regardless of what agency or person undertakes such other actions (40 CFR 1508.7). This section describes cumulative impacts associated with this project on resources. The ability to assess the potential cumulative impacts at the leasing stage for this project is limited for many resources due to the lack of site-specific information for potential future activities. Upon receipt of an APD for any of the lease parcels addressed in this document, more site-specific planning would be conducted in which the ability to assess contributions to cumulative impacts in a more detailed manner would be greater due to the availability of more refined site-specific information about proposed activities.

4.3.21.1 Past, Present and Reasonably Foreseeable Future Actions

Past, present, or reasonably foreseeable future actions that affect the same components of the environment as the Proposed Action are: grazing, roads, wildfire and prescribed fire, range improvement projects, and utility rights-of-way.

4.3.21.2 Cumulative Impacts by Resource

Cumulative effects for all resources in the MCFO are described in the final Big Dry RMP/EIS (pgs. 111 to 156) and the 1992 Oil and Gas Amendment of the Billings, Powder River, and South Dakota Resource Management Plans and Final Environmental Impact Statement and the 1994 Record of Decision and the 2008 Final Supplement to the Montana Statewide Oil and Gas Environmental Impact with a development alternative for coal bed natural gas production (4-1 to 4-310). Anticipated exploration and development activities associated with the lease parcels considered in this EA are within the range of assumptions used and effects described in this cumulative effects analysis for resources other than air, climate, and socio-economics resources. This previous analysis is hereby incorporated by reference for resources other than for air, climate, and economics resources.

4.3.21.2.1 Greenhouse Gas Emissions and Cumulative Impacts on Climate Change

The cumulative effects analysis area is the MCFO, with additional discussion at state-wide, national, and global scales for GHG emissions and climate change.

This section incorporates an analysis of the contributions of the Proposed Action to GHG emissions, followed by a general discussion of potential impacts to climate change. Potential emissions relate to those derived from potential exploration and development of fluid minerals. Additional emissions beyond the control of the BLM, and outside the scope of this analysis, would also occur during any needed refining processes, as well as end uses of final products.

Projected GHG emissions for this project and the MCFO RFD are compared below with recent, available inventory data at the State, national, and global scales. GHG emissions inventories can vary greatly in their scope and comprehensiveness. State, national, and global inventories are not necessarily consistent in their methods or in the variety of GHG sources that are inventoried (Climate Change SIR 2010). However, comparisons of emissions projected by the BLM for its oil and gas production activities are made with those from inventories at other scales for the sake of providing context for the potential contributions of GHGs associated with this project.

As discussed in the Air Quality section of Chapter 4, total projected BLM GHG emissions from the RFD are 610,741.1 metric tons/year CO₂e. Potential emissions under Alternative B would be approximately 0.041 percent of this total. Table 15 displays projected GHG emissions from non-BLM activities included in the Miles City RFD. Total projected emissions of non-BLM activities in the RFD in Appendix B are 1,382,890 metric tons/year of CO₂e. When combined with projected annual BLM emissions, this totals 1,383,139 metric tons/year CO₂e. Potential GHG emissions under Alternative B would be 0.042 percent of the estimated emissions for the entire RFD. Potential incremental emissions of GHGs from exploration and development of fluid minerals on parcels within Alternative B, and Alternative C, would be minor in the context of projected GHG contributions from the entire RFD for the MCFO.

Table 19. Projected non-BLM GHG Emissions Associated With the MCFO Reasonably Foreseeable Development Scenario for Fluid Mineral Exploration and Development.

Source	Non-BLM Long-Term GHG Emissions in tons/year				Emissions (metric tons/yr)
	CO ₂	CH ₄	N ₂ O	Co ₂ e	CO ₂ e
Conventional	545,689.1	5425.9	2.1	658,344.3	599,170.7

Natural Gas					
Coal Bed Natural Gas	274,925.2	5,330.5	0.9	387,135.7	351,302.8
Oil	422,033.9	2,576.2	1.2	476,522.7	432,416.3
Total	1,242,648.3	13,332.6	4.2	1,522,002.7	1,382,889.8

Montana's Contribution to U.S. and Global GHGs

Montana's GHG inventory (<http://www.eia.doe.gov/oiaf/1605/archive/gg04rpt/emission.html>, Center for Climate Strategies [CCS] 2007) shows that activities within the State contribute 0.6 percent of U.S and 0.076 percent of global GHG emissions (based on 2004 global GHG emission data from the IPCC, summarized in the Climate Change SIR 2010). Based on 2005 data in the state-wide inventory, the largest source of Montana's emissions is fossil fuel combustion to generate electricity, which accounts for approximately 27 percent of Montana's emissions. The next largest contributors are the agriculture and transportation sectors (each at approximately 22 percent) and fossil fuel production (13.6 percent).

GHG emissions from all major sectors in Montana in 2005 added up to a total of approximately 37 million metric tons of CO₂e (CCS 2007). Potential emissions from development of BLM lease parcels included in Alternative B would represent approximately 0.002 percent of the state-wide total of GHG emissions based on the 2005 state-wide inventory (CCS 2007).

The EPA published an inventory of U.S. GHG emissions, indicating gross U.S. emissions of 6,702 million metric tons, and net emissions of 5,797 million metric tons (when CO₂ sinks were considered) of CO₂e in 2011 (EPA 2013a). Potential annual emissions under Alternative B of this project would amount to approximately 0.000012 percent of gross U.S. total emissions. Global GHG emissions for 2004 (IPCC 2007, summarized by the Climate Change SIR 2010) indicated approximately 49 gigatonnes (10⁹ metric tons) of CO₂e emitted. Potential annual emissions under Alternative B would amount to approximately 0.000002 percent of this global total.

As indicated above, although the effects of GHG emissions in the global aggregate are well-documented, it is currently not possible to determine what specific effect GHG emissions resulting from a particular activity might have on climate or the environment. If exploration and development occur on the lease parcels considered under Alternative B, potential GHG emissions described above could incrementally contribute to the total volume of GHGs emitted to the atmosphere, and ultimately to climate change.

Mitigation measures identified in the Chapter 4 Air Quality section above may be in place at the APD stage to reduce GHG emissions from potential oil and gas development on lease parcels under Alternative B. This is likely because many operators working in Montana, South Dakota, and North Dakota are currently USEPA Natural Gas STAR Program Partners and future regulations may require GHG emission controls for a variety of industries, including the oil and gas industry (Climate Change SIR 2010).

4.3.21.2.2 Cumulative Impacts of Climate Change

As previously discussed in the Air Quality section of Chapter 4, it is impossible to identify specific impacts of climate change on specific resources within the analysis area. As

summarized in the Climate Change SIR (2010), climate change impacts can be predicted with much more certainty over global or continental scales. Existing models have difficulty reliably simulating and attributing observed temperature changes at small scales. On smaller scales, natural climate variability is relatively larger, making it harder to distinguish changes expected due to external forcings (such as contributions from local activities to GHGs). Uncertainties in local forcings and feedbacks also make it difficult to estimate the contribution of GHG increases to observed small-scale temperature changes (IPCC 2007, as cited by the Climate Change SIR 2010). Effects of climate change on resources are described in Chapter 3 of this EA and in the Climate Change SIR (2010).

4.3.21.3 Cumulative Impacts to Wildlife

For wildlife species, past and presently on-going oil and gas development, fire, farming, livestock grazing, traffic, and any other form of human and natural disturbances result in cumulative impacts to wildlife.

Construction of roads, production well pads, and other facilities would result in long term (>5 years) loss of habitat and forage in the analysis area. This would be in addition to acres disturbed, or habitats fragmented from various other adjacent activities. As new development occurs, direct and indirect impacts could continue to stress wildlife populations, most likely displacing the larger, mobile animals into adjacent habitat, and increasing competition with existing local populations. Non-mobile animals could be affected by increased habitat fragmentation and interruptions to preferred habitats.

Certain species are localized to some areas and rely on very key habitats during critical times of the year. Disturbance or human activities that could occur in winter range for big game, nesting and brood-rearing habitat for grouse and raptors could displace some or all of the species using a particular area or disrupt the normal life cycles of species. Wildlife and habitat in and around the project could be influenced to different degrees by various human activities. Some species and/or a few individuals from a species group could be able to adapt to these human influences over time.

4.3.21.4 Cumulative Impacts to Economic Conditions

The cumulative effects of Alternative B are summarized in Table 15 and Table 16. The leasing of an additional 7,945 acres of Federal minerals by the MCFO would result in a total of 442,811 acres leased from the MCFO within McCone, Powder River, Prairie, Richland and Roosevelt counties. The leasing of Federal minerals in these counties by the BLM would generate about \$1 million in Federal revenue. The redistribution of Federal revenue associated with leasing of these Federal minerals is estimated to generate nearly \$500,000 in State revenue for Montana and \$124,000 in local public revenue in the five counties. Federal oil and gas production associated with BLM minerals in these counties is also anticipated to increase as a result of leasing under Alternative B. Royalties associated with BLM minerals in these counties are estimated to generate \$11.5 million in Federal revenue. The redistribution of Federal royalty payments resulting from extraction of BLM minerals in the five counties would provide the State of Montana with \$5.5 million in public revenue while \$1.5 million would be distributed directly back to these producing counties.

Oil and gas related activities associated with Federal minerals leased from the MCFO generates millions in public revenue, stimulates economic activity in the public and private sectors, and can be attributed with supporting employment and income opportunities throughout the local rural economy. Total Federal revenue associated with the leasing and production of BLM administered minerals in McCone, Powder River, Prairie, Richland and Roosevelt counties under Alternative B is estimated to exceed \$12.4 million. The redistribution of Federal revenue from these minerals is anticipated to generate \$5.9 million in State revenue for Montana, and more than \$1.6 million will likely be returned to the five counties to fund law enforcement and fire departments, roads and highway maintenance, public education, local clinics/hospitals and county libraries. Public services and infrastructure investments by the State and local municipalities with redistributed Federal dollars supports employment and income in the public sector and in industries providing goods and services to the public sector. The drilling, servicing, and production resulting from BLM leasing of Federal minerals in the five counties also stimulates economic activity in the private sector, directly and indirectly supporting local employment and income in nearly every part of the economy. The total economic contribution of oil and gas related activities and public revenue associated with BLM leased minerals in McCone, Powder River, Prairie, Richland and Roosevelt counties under Alternative B is estimated to be 47 jobs and \$3 million in local wages and proprietor's income across the 8-county local economy.

4.4 Alternative C (BLM Preferred)

Under Alternative C, 2 whole and 5 partial parcels of the 18 lease parcels totaling 1,396.87 surveyed Federal mineral acres (680 surveyed BLM administered surface and 716.87 surveyed private surface) would be offered for competitive oil and gas lease sale. The remaining 11 lease parcels in whole and 5 partial lease parcels, encompassing 6,549.15 surveyed Federal mineral acres (2,958.73 surveyed BLM administered surface and 3,590.42 private surveyed surface) would be deferred pending further review.

4.4.1 Direct Effects Common to All Resources

The action of leasing the parcels in Alternative C would, in and of itself, have no direct impact on resources. Direct effects of leasing are the creation of a valid existing right and those related to the revenue generated by the lease sale receipts.

4.4.2 Indirect Effects Common to All Resources

Any potential effects on resources from the sale of leases would occur during lease exploration and development activities, which would be subject to future BLM decision-making and NEPA analysis upon receipt of an APD or sundry notice.

Oil and gas exploration and development activities such as construction, drilling, production, infrastructure installation, vehicle traffic and reclamation could be indirect effects from leasing the lease parcels in Alternative B. As mentioned above, it is speculative to make assumptions about whether a particular lease parcel would be sold and, even if so, it is speculative to assume when, where, how, or if future surface disturbing activities associated with oil and gas exploration and development such as well sites, roads, facilities, and associated infrastructure would be proposed. It is also not known how many wells, if any, would be drilled and/or completed, the types of technologies and equipment would be used and the types of

infrastructure needed for production of oil and gas. Thus, the types, magnitude and duration of potential impacts cannot be precisely quantified at this time, and would vary according to many factors.

Typical impacts to resources from oil and gas exploration and development activities such as well sites, roads, facilities, and associated infrastructure are described in the Miles City Oil & Gas Amendment/EIS (1994), the Big Dry RMP (1996), the Powder River RMP (1985), the Montana Statewide Oil & Gas Amendment/EIS (2003) and the Supplement (2008) to that document.

4.4.3 Air Resources

4.4.3.1 Air Quality

4.4.3.1.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82 percent due to approximately 6,549 acres of parcels proposed for deferral pending further review. Air quality impacts would likely be slightly less than those for Alternative B. Fewer leased acres would likely result in less future development and fewer emissions than Alternative B.

4.4.3.1.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.3.2 GHG Emissions

4.4.3.2.1 Direct and Indirect Effects

Alternative C CO₂e emissions are estimated to be 690 mtpy less than those for Alternative B.

4.4.3.2.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.3.3 Climate Change

4.4.3.3.1 Direct and Indirect Effects

Under Alternative C, climate change impacts would likely be slightly less than those for Alternative B.

4.4.3.3.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.4 Soil Resources

4.4.4.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82 percent due to approximately 6,549 acres of parcels proposed for deferral pending further review. Less than one percent of the soils rated as low potential for restoration would be deferred. There are no CSU 12-1 soils stipulations applied to the deferred parcels. Soils are the same as those described in the Effected Environment section 3.3.

4.4.4.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.5 Water Resources

4.4.5.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82 percent, due to approximately 6,549 acres of the lease parcels proposed for deferral pending further review.

The potentially impacted acres on water resources would be decreased by 6,549.15 acres.

4.4.5.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.6 Vegetation Resources

4.4.6.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82%, due to approximately 6,549 acres of the lease parcels proposed for deferral pending further review.

4.4.6.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.7 Riparian-Wetland Habitats

4.4.7.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82 percent, due to approximately 6,549 acres of the lease parcels proposed for deferral pending further review.

The potentially impacted acres on riparian resources would be decreased by 26 acres.

4.4.7.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.8 Special Status Plant Species

4.4.8.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82%, due to approximately 6,549 acres of the lease parcels proposed for deferral pending further review.

4.4.8.2 Mitigation

Mitigation would be that same as Alternative B.

4.4.9 Wildlife & Fisheries/Aquatics

4.4.9.1 Direct and Indirect Effects

Direct and indirect impacts would be similar to Alternative B; however, the area impacted would be reduced by 82%, due to these lease parcels proposed for deferral pending further review. If deferred, this alternative would reduce the amount of parcels/acreage proposed in white-tailed deer, mule deer, and pronghorn winter ranges, whooping crane potential suitable habitat, Sprague's pipit habitat, and within both sage grouse and sharp-tailed grouse habitat. Potential impacts to these resources would be reduced under this alternative. The parcels proposed for deferral overlap with the range of eleven BLM sensitive/special status aquatic species (pallid sturgeon, paddle fish, blue sucker, sturgeon chub, sauger, pearl dace, snapping turtle, spiny softshell, northern leopard frog, plains spadefoot and great plains toad). If deferred, this alternative would reduce the impacts to these BLM sensitive aquatic species' habitat.

4.4.9.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.10 Cultural

4.4.10.1 Direct and Indirect Effects

Impacts would be similar to those disclosed in Alternative B; however, the area impacted would be reduced by 82%, due to these lease parcels proposed for deferral pending further review. Specifically, potential effects would not occur on the 16 whole or partial lease parcels consisting of 6,549 acres proposed for deferral. The new analyses for parcels to be leased are as follows below.

Based on modeling, all or portions of four lease parcels (MTM 105431-HF (120 acres); MTM 105431-HG (160 acres); MTM 105431-HH (80 acres); MTM 105431-HJ (317 acres)), in Powder River County (677 acres) might contain 8 cultural sites of which one to two could have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Based on modeling, all or portions of two lease parcels (MTM 102757-WT (319 acres); MTM 102757-WW (361 acres)), in Prairie County (680 acres) might contain up to 8 cultural sites of which one to two could have the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Based on modeling, a portion of one lease parcel (MTM 105431-H9 (40 acres)) located in Roosevelt County (40 acres) might contain one cultural site which could have potential to be eligible or considered eligible for listing on the National Register of Historic Places.

Leasing the 1,397 acres of federal minerals within the above Counties could directly or indirectly affect 15 cultural sites with 1 to 3 sites having the potential to be eligible or considered eligible for listing on the National Register of Historic Places.

The Reasonable Foreseeable Development (RFD and Appendix D) scenario for the lease parcels is the same as Alternative B.

4.4.10.2 Mitigation

Mitigation would be the same as Alternative B where the application of standard lease terms, stipulations, and cultural lease notices provide mechanisms to protect vulnerable significant cultural resource values on these lease parcels (Appendix A). Lease notice LN 14-2 would be applied to 1 lease parcel (MTM 105431-H9).

4.4.11 Native American Religious Concerns

4.4.11.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B. Areas potentially impacted would be reduced by approximately 82 % due to 6,549 acres being deferred pending further analysis. The deferred parcels include Parcel MTM 105431-H9 which contains the three stone circle sites mentioned in Chapter 3.

4.4.11.2 Mitigation

If the parcels are leased, mitigation would be the same as Alternative B.

4.4.12 Paleontology

4.4.12.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82 percent, due to approximately 6,549 acres of lease parcels proposed for deferral pending further review. Specifically, effects would not occur on the lease parcels in whole or part proposed for deferral.

4.4.12.2 Mitigation

Mitigation would be the same as Alternative B, except the recommendation to apply Paleontological lease notice 14-12 would only apply to 2 whole leases and portions of 5 others because lease parcels in whole or part are proposed for deferral.

4.4.13 Visual Resources

4.4.13.1 Direct and Indirect Effects

Under this alternative, 2 whole and 5 partial parcels that include 1,396.87 surveyed surface acres of which 680 acres are BLM administered surface and 716.87 acres are non-federal surface would be offered for lease.

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced, due to approximately 6,549.15 surface acres of 11 whole and 5 partial lease parcels being proposed for deferral, pending further review. The parcels or portions of parcels proposed for deferral consist of 2,958.73 BLM administered surface acres and 3,590.42 non-federal surface acres.

There are no areas located within a VRM Class II management objective.

4.4.13.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.14 Forest and Woodland Resources

4.4.14.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced substantially, due to approximately 6,549 acres of lease parcels proposed for deferral pending further review. Under this alternative, acreage potentially impacted would be approximately 10 acres of riparian woodland.

4.4.14.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.15 Livestock Grazing

4.4.15.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B. The deferred parcels pending further review do not have grazing authorizations.

4.4.15.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.16 Recreation and Travel Management

4.4.16.1 Direct and Indirect Effects

Under this alternative, 2 whole and 5 partial parcels that include 1,396.87 surveyed surface acres of which 680 acres are BLM administered surface and 716.87 acres are non-federal surface would be offered for lease.

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced, due to approximately 6,549.15 surface acres of 11 whole and 5 partial lease parcels being proposed for deferral, pending further review. The parcels or portions of parcels proposed for deferral consist of 2,958.73 BLM administered surface acres and 3,590.42 non-federal surface acres.

There are no Special Recreation Management Areas or current Travel Management Areas within any of the proposed leased areas or deferred areas.

4.4.16.2 Mitigation

Mitigation would be the same as Alternative B.

4.4.17 Lands and Realty

4.4.17.1 Direct and Indirect Effects

Under this alternative, 2 whole and 5 partial parcels that include 1,396.87 surveyed surface acres of which 680 acres are BLM administered surface and 716.87 acres are non-federal surface would be offered for lease.

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced, due to approximately 6,549.15 surface acres of 11 whole and 5 partial lease parcels being proposed for deferral, pending further review. The parcels or portions of parcels proposed for deferral consist of 2,958.73 BLM administered surface acres and 3,590.42 non-federal surface acres.

Based on the Master Title plats and LR2000 reports, parcel MTM-102757-WT would be affected by authorized BLM ROWs on BLM administered surface.

4.4.17.2 Mitigation

Measures would be taken to avoid disturbance to or impacts to existing rights-of-way, in the event of any oil and gas exploration and development activities. Any new “off-lease” or third party rights-of-way required across federal surface for exploration and/or development of the 18 parcels would be subject to lands and realty stipulations to protect other resources as determined by environmental analyses. In order to protect the existing rights-of-way it is recommended that LN 14-1 be applied to lease parcel MTM-102757-WT.

4.4.18 Minerals

4.4.18.1 Fluid Minerals

4. 4.18.1.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 82%, due to approximately 6,549.15 acres of lease parcels proposed for deferral pending further review. The remaining 11 whole and 5 partial lease parcels would be offered for lease subject to major (NSO) or moderate (CSU) constraints and/or standard lease terms and conditions.

Deferring lease parcels would result in delays of some development plans, relocation of development to state or private leases, or completely eliminate development plans because of the need to include federal acreage as part of a plan. In addition, less natural gas or crude oil would enter the public markets.

4.4.19 Special Designations

4.4.19.1 Direct and Indirect Effects

Under this alternative, 2 whole parcels and parts of 5 would be offered for lease. Totaling 1,397 surveyed surface acres of which are 680 BLM administered surface and 717 acres of non-federal surface.

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced to 17.6% of Alternative B acres (1,397 acres) due to approximately 6,548 surface acres of all or portions of 16 lease parcels being proposed for deferral, pending further review. The parcels or portions of parcels proposed for deferral consist of 2,958 BLM administered surface acres and 3,590 non-federal surface acres.

There are no Lease parcels, located within the 3 mile sensitive Setting Consideration Zone (SCZ) around the Lewis and Clark National Historic Trail Corridor.

4.4.19.2 Mitigation

Since no parcels would be offered, under Alternative C that would be in the Lewis and Clark NHT no mitigation measures would be necessary.

4.4.20 Social and Economic Conditions

4.4.20.1 Social

4.4.20.1.1 Direct and Indirect Effects

Direct and indirect impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by less than 82%, due to the deferral of 6,549.15 acres of lease parcels in McCone, Richland, Roosevelt, Prairie, and Powder River Counties.

4.4.20.2 Economics

4.4.20.2.1 Direct and Indirect Impacts

Economic impacts associated with Alternative C would be very similar to those described for Alternative B. Under this alternative, leasing an additional 1,397 acres of federal minerals could increase average annual oil and gas leasing and rent revenues to the federal government by an estimated \$6,000. Average annual leasing and rent revenues that could be distributed to the state government could increase by an estimated \$3,000. Average annual federal oil and gas royalties would increase by an estimated \$36,000. Average annual royalties distributed to the state could increase by an estimated \$17,000 and revenue distributed to the five counties could increase by \$5,000.

Total average annual federal revenues and associated annual rent and royalty revenues related to average annual production of federal minerals could amount to an estimated \$42,000. Total average annual revenues from leasing, rent, and royalties distributed to the state could be an estimated \$20,000. Total estimated revenues distributed to the counties could be about \$5,000.

The estimated combined total average annual employment and income supported by additional federal oil and gas leasing, distributions of royalties to local governments, drilling wells, and production would amount to no change in employment and an additional \$12,000 labor income within the local economy (IMPLAN, 2014).

The annual SCC associated with Alternative C oil and gas development is \$6,769 (in 2011 dollars). As noted earlier, the estimated SCC is not directly comparable to economic contributions.

Total federal contribution under Alternative C and anticipated related exploration, development, and production of oil and gas could cause local employment and labor income to be very similar to impacts expected from Alternative B.

4.4.21 Cumulative Impacts- Alternative C

Direct and indirect impacts would be similar to Alternative B. Under this alternative, the cumulative effects of federal mineral leasing within the local economy as well as the specific effects of leasing an additional 1,397 acres are summarized in Table 15 and Table 16. These tables also display in comparative form the cumulative effects of alternatives A, B, and C.

4.4.21.1 Past, Present and Reasonably Foreseeable Future Actions

Past, present, or reasonably foreseeable future actions that affect the same components of the environment as the Proposed Action are: grazing, roads, wildfire and prescribed fire, range improvement projects, and utility right-of-ways.

4.4.21.2 Cumulative Impacts by Resource

Cumulative effects for all resources in the MCFO are described in the final Big Dry RMP/EIS (pgs. 111 to 156) and the 1992 Oil and Gas Amendment of the Billings, Powder River, and South Dakota Resource Management Plans and Final Environmental Impact Statement and the 1994 Record of Decision and the 2008 Final Supplement to the Montana Statewide Oil and Gas Environmental Impact with a development alternative for coal bed natural gas production (4-1 to 4-310). Anticipated exploration and development activity associated with the lease parcels considered in this EA are within the range of assumptions used and effects described in this cumulative effects analysis for resources other than climate, wildlife, and economics resources.

4.4.21.3 Greenhouse Gas Emissions and Cumulative Impacts on Climate Change

CO₂e emissions are estimated to be 690 metric tons/year less than Alternative B.

4.4.21.4 Cumulative Impacts of Climate Change

Due to the slight decrease in CO₂e emissions under Alternative C, cumulative climate change impacts on resources would be slightly less than those for Alternative B.

4.4.21.5 Cumulative Impacts to Wildlife & Fisheries/Aquatics

Cumulative impacts would be the same as Alternative B; however, the area potentially impacted would be reduced by 11 whole parcels and portions of 5 other parcels pending further review. If the remaining lease parcels are developed, potential additional cumulative impacts to wildlife would occur over less area than what is described in Alternative B.

4.4.21.6 Cumulative Impacts to Economic Conditions:

Direct and indirect impacts would be similar to Alternative B. Under this alternative, the cumulative effects of federal mineral leasing within the local economy as well as the specific effects of leasing an additional 1,397 acres are summarized in Table 15 and Table 16. These tables also display in comparative form the cumulative effects of alternatives A, B, and C.

5.0 CONSULTATION AND COORDINATION

5.1 Persons, Agencies, and Organizations Consulted

Coordination with MFWP was conducted for the 18 lease parcels being reviewed and in the completion of this EA in order to prepare the analysis, identify protective measures, and apply stipulations and lease notices associated with these parcels being analyzed. Recommendations by the USFWS applied in previous lease sale EAs were also applied to the 18 lease parcels being reviewed. A letter was sent to the USFWS and MFWP during the 15-day scoping and 30-day public comment periods requesting comments on the 18 parcels being reviewed.

The BLM consults with Native Americans under Section 106 of the National Historic Preservation Act. The BLM sent letters to tribes in Montana, North and South Dakota and Wyoming at the beginning of the 15 day scoping period informing them of the potential for the 18 parcels to be leased and inviting them to submit issues and concerns BLM should consider in the environmental analysis. Letters were sent to the Tribal Presidents and THPO or other cultural contacts for the Cheyenne River Sioux Tribe, Crow Tribe of Montana, Crow Creek Sioux Tribe, Eastern Shoshone Tribe, Ft. Peck Tribes, Lower Brule Sioux Tribe, the Mandan,

Hidasta, and Arkira Nation, Northern Arapaho Nation, Northern Cheyenne Tribe, Oglala Sioux Tribe, Rosebud Sioux Tribe of Indians, Standing Rock Sioux Tribe, and Turtle Mountain Band of Chippewa. In addition to scoping letters, THPOs also received file search results from the preliminary review of parcels conducted by BLM. The BLM sent a second letter with a copy of the EA to the tribes informing them about the 30 day public comment period for the EA and solicit any information BLM should consider before making a decision whether to offer any or all of the 18 parcels for sale.

5.2 Summary of Public Participation

5.2.1 Scoping

Public scoping for this project was conducted through a 15-day scoping period advertised on the BLM Montana State Office website and posting on the field office website NEPA notification log. Scoping was initiated March 25, 2014. Montana Fish Wildlife and Parks (MFWP) submitted comments on the October 2014 lease sale.

MFWP recommended applying a 1/4 mile buffer along the parcels along Schoolhouse Coulee, Renz Creek, and the tributary to Two-mile creek in parcels MTM 105431-HB and MTM 105431-H8. In review, the BLM have already applied a No Surface Occupancy (NSO 11-2) for parcel MTM 105431 HB where Schoolhouse Coulee and Renz Creek occur. The Big Dry RMP does not have a stipulation for a 1/4 mile buffer along tributaries of waterways. After reviewing nominated lease parcel MTM 105431-H8, it is determined that the No Surface Occupancy stipulation for waterbodies, floodpains, and riparian areas should not be applied. Two-mile Creek does run through the parcel, but according to the best available information, it is ephemeral at this location and appears to lack defined channel. If this lease was to be developed and sensitive resources were identified at the proposed well location, BLM would use its regulatory authority to move the proposed well location up to 660 feet in order to protect sensitive resources.

MFWP recommend applying timing limitation 13-1 for big game winter ranges. In review, the BLM have already applied this timing stipulation to the necessary parcels. MFWP recommend surveys for sharp-tailed grouse leks and sage grouse leks to occur prior to development of some of the parcels. The Big Dry RMP or Powder River RMP does not have a stipulation for pre-development surveys for sage grouse or sharp-tailed grouse. However, in some cases where necessary, the BLM has had required companies to conduct these surveys prior to authorizing development at the Application for Permit to Drill (APD) stage before development. Recent inventories for sage grouse leks have not been conducted within some of the parcels. If the leases were to be developed, inventories would be conducted if the leases were to be developed at the APD stage of development to determine the presence or absence of sage grouse leks. Similarly, recent inventories of sharp-tailed grouse dancing grounds have not been conducted within some of the parcels. Thus, inventories would be conducted prior to development at the APD stage before development to determine the presence or absence of sharp-tailed grouse dancing grounds.

5.3 List of Preparers

Table 20. List of Preparers

Name	Title	Responsible for the Following Section(s) of this Document
Susan Bassett	Air Specialist	Air Resources
Bobby Baker	Wildlife Biologist	Wildlife
Chris Robinson	Hydrologist	Water Resources/Riparian Vegetation
Will Hubbell	Archaeologist	Cultural/Special Designations
Josh Halpin	Range Management Specialist	Soils
Shane Findlay	Supervisory Land Use Specialist	Recreation/VRM/Travel Management
Russell Slatton	Natural Resource Specialist	GIS
Kirk Anderson	Rangeland Management Specialist	Livestock Grazing/Vegetation/Invasive Species
Doug Melton	Archeologist	Native American Religious Concerns
Greg Liggitt	Paleontologist	Paleontology
Beth Klempel	Realty Specialist	Lands/Realty
Paul Helland	Petroleum Engineer	Fluid Minerals/RFD
Jon David	Natural Resource Specialist	EA Lead/Forestry
Kathy Bockness	Planning & Environmental Coordinator	NEPA
Jessica Montag	Social Analyst	Social Analysis
Jennifer Dobbs	Economist	Economic Analysis
Samantha Iron Shirt	Legal Land Examiner-Sale Lead	Expressions of Interest/Lease Sale

In addition to the primary preparers listed above, the following individuals provided document review:

Todd Yeager
Diane Friez

Field Manager
District Manager

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7.0 DEFINITIONS

The North American Industry Classification System (NAICS) is the standard used by federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy. NAICS was developed under the auspices of the Office of Management and Budget (OMB), and adopted in 1997 to replace the Standard Industrial Classification (SIC) system and to allow for a high level of comparability in business statistics among the North American countries.

IMPLAN: The IMPLAN Model is the most flexible, detailed and widely used input-output impact model system in the U.S. It provides users with the ability to define industries, economic relationships and projects to be analyzed. It can be customized for any county, region or state, and used to assess "multiplier effects" caused by increasing or decreasing spending in various parts of the economy. This can be used to assess the economic impacts of resource management decisions, facilities, industries, or changes in their level of activity in a given area. The current IMPLAN input-output database and model is maintained and sold by MIG, Inc. (Minnesota IMPLAN Group). The 2007 data set was used in this analysis is.

APPENDIX A

PARCEL NUMBER	PARCEL DESCRIPTION	PROPOSED FOR LEASING ALTERNATIVE B	PROPOSED FOR LEASING IF EA INCLUDES ALTERNATIVE C	PROPOSED FOR DEFERRAL-NO LEASING
MTM 102757-WT	T. 13 N, R. 45 E, PMM, MT SEC. 18 LOTS 1,2; SEC. 18 NE,E2NW; SEC. 20 ALL; PRAIRIE COUNTY 961.22 AC ACQ	CR 16-1 (ALL LANDS) LN-14-1 SEC. 18 W2NE; LN 14-11 (ALL LANDS) LN 14-12 (ALL LANDS) LN 14-15 (ALL LANDS) NSO 11-2 SEC. 20 E2E2; NSO 11-8 SEC. 18 LOT 2; SEC. 18 S2NE,SENW; SEC. 20 NWNW; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 SEC. 18 LOTS 1,2; SEC. 18 NE,E2NW; SEC. 20 N2,NESW,N2SE,SESE;	T. 13 N, R. 45 E, PMM, MT SEC. 18 LOTS 1,2; SEC. 18 NE,E2NW; SEC. 20 SENE;	T. 13 N, R. 45 E, PMM, MT SEC. 20 NENE,W2NE,NW,S2; PRAIRIE COUNTY Pending further review of sensitive soil areas being analyzed in the current MCFO RMP planning effort.

APPENDIX A

PARCEL NUMBER	PARCEL DESCRIPTION	PROPOSED FOR LEASING ALTERNATIVE B	PROPOSED FOR LEASING IF EA INCLUDES ALTERNATIVE C	PROPOSED FOR DEFERRAL-NO LEASING
MTM 102757-WW	T. 14 N, R. 45 E, PMM, MT SEC. 2 LOTS 3,4; SEC. 2 S2NW,SW; SEC. 4 LOTS 1-4; SEC. 4 S2N2,S2; PRAIRIE COUNTY 958.02 AC ACQ	CR 16-1 (ALL LANDS) LN 14-11 (ALL LANDS) LN 14-12 (ALL LANDS) LN 14-15 (ALL LANDS) NSO 11-2 SEC. 4 LOTS 1-3; SEC. 4 S2NE,SWNW,W2SW,SE; NSO 11-4 SEC. 4 SWNE, S2NW, N2SW, SESW,W2SE; TES 16-2 (ALL LANDS) TL 13-1 SEC. 2 LOT 4; SEC 2 S2NW, NWNW; SEC. 4 LOTS 1-4; SEC. 4 S2N2, S2; TL 13-3 (ALL LANDS) TL 13-4 SEC. 4 LOTS 1,2;	T. 14 N, R. 45 E, PMM, MT SEC. 2 LOTS 3,4; SEC. 2 S2,NW; SEC. 4 LOT 4; SEC. 4 SENW,E2SW; PRAIRIE COUNTY	T. 14 N, R. 45 E, PMM, MT SEC. 2 SW; SEC. 4 LOTS 1-3; SEC. 4 S2NE,SWNW,W2SW,SE; PRAIRIE COUNTY Pending further review of sensitive soils and sage grouse areas being analyzed in the current MCFO RMP planning effort.
MTM 105431-HA	T. 26 N, R. 50 E, PMM, MT SEC. 24 SENE; MCCONE COUNTY 40.00 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) LN 14-15 (ALL LANDS) TES 16-2 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of badlands rock outcrop areas being analyzed in the current MCFO RMP planning effort.

APPENDIX A

PARCEL NUMBER	PARCEL DESCRIPTION	PROPOSED FOR LEASING ALTERNATIVE B	PROPOSED FOR LEASING IF EA INCLUDES ALTERNATIVE C	PROPOSED FOR DEFERRAL-NO LEASING
MTM 105431-HB	T. 26 N, R. 52 E, PMM, MT SEC. 3 LOTS 1-3; SEC. 3 S2NE, SENW, SE; SEC. 10 E2; SEC. 15 NWNE, W2SW; RICHLAND COUNTY 830.48 AC PD	CR 16-1 (ALL LANDS) CSU 12-1 SEC. 10 N2, SE; LN-14-1 SEC. 10 N2E2; LN 14-12 (ALL LANDS) LN 14-14 (ALL LANDS) LN 14-15 (ALL LANDS) NSO 11-2 SEC. 3 LOT 2; SEC. 3 S2NE; NESE; TES 16-2 (ALL LANDS) TL 12-1 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of badlands rock outcrop areas being analyzed in the current MCFO RMP planning effort.
MTM 105431-H6	T. 26 N, R. 55 E, PMM, MT SEC. 4 LOT 4; SEC. 4 SWNW, SW; RICHLAND COUNTY 241.91 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) LN 14-15 (ALL LANDS) TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of sensitive soil areas being analyzed in the current MCFO RMP planning effort.
MTM 105431-H8	T. 27 N, R. 55 E, PMM, MT SEC. 30 LOT 4; SEC. 30 S2SE; RICHLAND COUNTY 116.82 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) LN-14-1 SEC. 30 LOT 4; LN 14-14 (ALL LANDS) LN 14-15 (ALL LANDS) NSO 11-4 SEC. 30 LOT 4; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 (ALL LANDS)	DEFER ALL LANDS	DEEFER ALL LANDS Pending further review of sensitive soil areas being analyzed in the current MCFO RMP planning effort.

APPENDIX A

PARCEL NUMBER	PARCEL DESCRIPTION	PROPOSED FOR LEASING ALTERNATIVE B	PROPOSED FOR LEASING IF EA INCLUDES ALTERNATIVE C	PROPOSED FOR DEFERRAL-NO LEASING
MTM 105431-H9	T. 30 N, R. 58 E, PMM, MT SEC. 1 LOT 1; SEC. 12 NENE,S2NE; ROOSEVELT COUNTY 160.02 AC PD	CR 16-1 (ALL LANDS) LN 14-2 (ALL LANDS) LN 14-12 (ALL LANDS) LN 14-14 (ALL LANDS) LN 14-15 (ALL LANDS) NSO 11-2 (ALL LANDS) TES 16-2 (ALL LANDS)	T. 30 N, R. 58 E, PMM, MT SEC. 12 NENE; ROOSEVELT COUNTY	T. 30 N, R. 58 E, PMM, MT SEC. 1 LOT 1; SEC. 12 S2NE; ROOSEVELT COUNTY Pending further review of sensitive soil areas being analyzed in the current MCFO RMP planning effort.
MTM 105431-JA	T. 30 N, R. 59 E, PMM, MT SEC. 6 LOT 4; ROOSEVELT COUNTY 39.94 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) LN 14-15 (ALL LANDS) NSO 11-2 (ALL LANDS) TES 16-2 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of sensitive soil areas that are being analyzed in the current MCFO RMP planning effort.
MTM 105431-HC	T. 8 S, R. 51 E, PMM, MT SEC. 9 SESW,SE; SEC. 10 NENE,S2NE,S2; POWDER RIVER COUNTY 640.00 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 9 SESW,NWSE; SEC. 10 NENE,S2NE,NESE,SWSE; TES 16-2 (ALL LANDS) TL 13-1 SEC. 10 ALL; TL 13-3 SEC. 9 SESW; SEC. 10 S2SE;	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of sensitive soil areas being analyzed in the current MCFO RMP planning effort.
MTM 105431-HD	T. 8 S, R. 51 E, PMM, MT SEC. 11 ALL; POWDER RIVER COUNTY 640.00 AC PD	CR 16-1 (ALL LANDS) NSO 11-2 SEC. 11 SWNW,SWSW; LN 14-12 (ALL LANDS) TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 SEC. 11 N2N2, S2S2;	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of sensitive soil areas in current MCFO RMP planning effort.

APPENDIX A

PARCEL NUMBER	PARCEL DESCRIPTION	PROPOSED FOR LEASING ALTERNATIVE B	PROPOSED FOR LEASING IF EA INCLUDES ALTERNATIVE C	PROPOSED FOR DEFERRAL-NO LEASING
MTM 105431-HE	T. 8 S, R. 51 E, PMM, MT SEC. 26 SW; POWDER RIVER COUNTY 160.00 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 26 NESW; NSO 11-2 SEC. 26 NESW; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of sensitive soil areas in current MCFO RMP planning effort.
MTM 105431-HG	T. 9 S, R. 51 E, PMM, MT SEC. 11 NE; POWDER RIVER COUNTY 160.00 AC PD	CR 16-1 (ALL LANDS) LN 14-11 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-8 (ALL LANDS) TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 (ALL LANDS)	T. 9 S, R. 51 E, PMM, MT SEC. 11 NE; POWDER RIVER COUNTY	
MTM 105431-HH	T. 9 S, R. 51 E, PMM, MT SEC. 22 E2; SEC. 27 N2NW,SWNW; POWDER RIVER COUNTY 440.00 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 22 W2NE,SENE,NESE; SEC. 27 NENW; TL 13-1 (ALL LANDS) TES 16-2 (ALL LANDS)	T. 9 S, R. 51 E, PMM, MT SEC. 22 E2NE; POWDER RIVER COUNTY	T. 9 S, R. 51 E, PMM, MT SEC. 22 W2NE,SE; SEC. 27 N2NW,SWNW; POWDER RIVER COUNTY Pending further review of sensitive soils areas in current MCFO RMP planning effort.
MTM 105431-HJ	T. 9 S, R. 51 E, PMM, MT SEC. 27 S2SW; SEC. 28 SESE; SEC. 33 NENE; SEC. 34 LOT 1; SEC. 34 W2NW,NWSW; POWDER RIVER COUNTY 316.87 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 27 S2SW; SEC. 28 SESE; SEC. 33 NENE; SEC. 34 NWNW,NWSW; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS)	T. 9 S, R. 51 E, PMM, MT SEC. 27 S2SW; SEC. 28 SESE; SEC. 33 NENE; SEC. 34 LOT 1; SEC. 34 W2NW,NWSW; POWDER RIVER COUNTY	

APPENDIX A

PARCEL NUMBER	PARCEL DESCRIPTION	PROPOSED FOR LEASING ALTERNATIVE B	PROPOSED FOR LEASING IF EA INCLUDES ALTERNATIVE C	PROPOSED FOR DEFERRAL-NO LEASING
MTM 105431-HF	T. 8 S, R. 52 E, PMM, MT SEC. 32 ALL; POWDER RIVER COUNTY 640.00 AC PD	CR 16-1 (ALL LANDS) LN 14-11 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 32 N2NE,W2SW,SESW; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 SEC. 32 SWNE, NWNW, S2NW, SW W2SE SESE.	T. 8 S, R. 52 E, PMM, MT SEC. 32 N2NW, SESW; POWDER RIVER COUNTY	T. 8 S, R. 52 E, PMM, MT SEC. 32 NE,S2NW,W2SW,NESW,SE; POWDER RIVER COUNTY Pending further review of sensitive soil areas in current MCFO RMP planning effort.
MTM 105431-HK	T. 9 S, R. 52 E, PMM, MT SEC. 23 ALL; POWDER RIVER COUNTY 640.00 AC PD	CR 16-1 (ALL LANDS) NSO 11-2 SEC. 23 SWNE,SWSW; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 SEC. 23 S2NE, S2.	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of mule deer winter range habitat in the current MCFO RMP planning effort.
MTM 105431-HL	T. 9 S, R. 52 E, PMM, MT SEC. 26 ALL; POWDER RIVER COUNTY 640.00 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 26 S2NE,NENW,NESE; TES 16-2 (ALL LANDS) TL 13-1 (ALL LANDS) TL 13-3 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of mule deer winter range habitat in the current MCFO RMP planning effort.
MTM 105431-HM	T. 9 S, R. 52 E, PMM, MT SEC. 27 E2; POWDER RIVER COUNTY 320.00 AC PD	CR 16-1 (ALL LANDS) LN 14-12 (ALL LANDS) NSO 11-2 SEC. 27 NWSE; TL 13-1 (ALL LANDS) TL 13-3 (ALL LANDS) TES 16-2 (ALL LANDS)	DEFER ALL LANDS	DEFER ALL LANDS Pending further review of mule deer winter range habitat in the current MCFO RMP planning effort.

Appendix B – Miles City Field Office Stipulation Descriptions

Stipulation Number	Stipulation Name/Brief Description
CR 16-1	<p>CULTURAL RESOURCES LEASE STIPULATION</p> <p>This lease may be found to contain historic properties and/or resources protected under the National Historic Preservation Act (NHPA), American Indian Religious Freedom Act, Native American Graves Protection and Repatriation Act, E.O. 13007, or other statutes and executive orders. The BLM will not approve any ground disturbing activities that may affect any such properties or resources until it completes its obligations under applicable requirements of the NHPA and other authorities. The BLM may require modification to exploration or development proposals to protect such properties, or disapprove any activity that is likely to result in adverse effects that cannot be successfully avoided, minimized or mitigated.</p>
CSU 12-1	<p>CONTROLLED SURFACE USE STIPULATION</p> <p>Surface occupancy or use is subject to the following special operating constraint: Prior to surface disturbance on slopes over 30 percent, an engineering/reclamation plan must be approved by the authorized officer.</p>
CSU 12-4	<p>CONTROLLED SURFACE USE STIPULATION</p> <p>All surface-disturbing activities, semi-permanent and permanent facilities in Visual Resource Management (VRM) Class II areas may require special design, including location, painting and camouflage, to blend with the natural surroundings and meet the visual quality objectives for the area.</p>
LN 14-1	<p>LEASE NOTICE</p> <p>Land Use Authorizations incorporate specific surface land uses allowed on Bureau of Land Management (BLM) administered lands by authorized officers and those surface uses acquired by BLM on lands administered by other entities. These BLM authorizations include rights-of-way, leases, permits, conservation easements, and recreation and public purpose leases and patents.</p>
LN 14-11	<p>LEASE NOTICE GREATER SAGE-GROUSE HABITAT</p> <p>The lease may in part, or in total contain important Greater Sage-Grouse habitats as identified by the BLM, either currently or prospectively. The operator may be required to implement specific measures to reduce impacts of oil and gas operations on the Greater Sage-Grouse populations and habitat quality. Such measures shall be developed during the application for permit to drill on-site and environmental review process and will be consistent with the lease rights granted.</p>
LN 14-12	<p>LEASE NOTICE PALEONTOLOGICAL RESOURCE INVENTORY REQUIREMENT</p> <p>This lease has been identified as being located within geologic units rated as being moderate to very high potential for containing significant paleontological resources. The locations meet the criteria for class 3, 4 and/or 5 as set forth in the Potential Fossil Yield Classification System, WO IM 2008-009, Attachment 2-2. The BLM is responsible for assuring that the leased lands are examined to determine if paleontological resources are present and to specify mitigation measures. Guidance for application of this requirement can be found in WO IM 2008-009 dated October 15, 2007, and WO IM 2009-011 dated October 10, 2008.</p> <p>Prior to undertaking any surface-disturbing activities on the lands covered by this lease, the lessee or project proponent shall contact the BLM to determine if a paleontological resource inventory is required. If an inventory is required, the lessee or project proponent will complete the inventory subject to the following:</p> <ul style="list-style-type: none"> the project proponent must engage the services of a qualified paleontologist, acceptable to the BLM, to conduct the inventory. the project proponent will, at a minimum, inventory a 10-acre area or larger to incorporate possible project relocation which may result from environmental or other resource considerations. <p>paleontological inventory may identify resources that may require mitigation to the</p>

Stipulation Number	Stipulation Name/Brief Description
	satisfaction of the BLM as directed by WO IM 2009-011.incorporate possible project relocation which may result from environmental or other resource considerations. paleontological inventory may identify resources that may require mitigation to the satisfaction of the BLM as directed by WO IM 2009-011.
LN 14-14	<p>LEASE NOTICE CULTURAL VISUAL SETTING</p> <p>The lease is located adjacent to known historic properties that are or may be eligible for listing on the National Register of Historic Places (NRHP). The lease may in part or whole contribute to the importance of the historic properties and values, and listing on the NRHP. The operator may be required to implement specific measures to reduce impacts of oil and gas operations on historic properties and values. These measures may include, but are not limited to, project design, location, painting and camouflage. Such measures shall be developed during the on-site inspection and environmental review of the application for permit to drill (APD), and shall be consistent with lease rights.</p> <p>The goal of this Lease Notice is to provide information to the lessee and operator that would help design and locate oil and gas facilities to preserve the integrity and value of historical properties that are or may be listed on the National Register of Historic Places.</p> <p>This notice is consistent with the present Montana guidance for cultural resource protection related to oil and gas operations (NTL-MSO-85-1).</p>
LN 14-15	<p>LEASE NOTICE SPRAGUE'S PIPIT</p> <p>The lease area may contain habitat for the federal candidate Sprague's pipit. The operator may be required to implement specific measures to reduce impacts of oil and gas operations on Sprague's pipits, their habitat, and overall population. Such measures would be developed during the application for permit to drill and environmental review processes, consistent with lease rights.</p> <p>If the US Fish and Wildlife Service lists the Sprague's pipit as threatened or endangered under Endangered Species Act, the BLM would enter into formal consultation on proposed permits that may affect the Sprague's pipit and its habitat. Restrictions, modifications, or denial of permits could result from the consultation process.</p>
NSO 11-2	<p>NO SURFACE OCCUPANCY STIPULATION</p> <p>No surface occupancy or use is allowed within riparian areas, 100-year flood plains of major rivers, and on water bodies and streams.</p>
NSO 11-4	<p>NO SURFACE OCCUPANCY STIPULATION</p> <p>No surface occupancy or use is allowed within one-quarter mile of grouse leks.</p>
NSO 11-8	<p>NO SURFACE OCCUPANCY STIPULATION</p> <p>No surface occupancy or use is allowed within one-half mile of known ferruginous hawk nest sites which have been active within the past 2 years.</p>
NSO 11-9	<p>NO SURFACE OCCUPANCY STIPULATION</p> <p>No surface occupancy or use is allowed within one-quarter mile of wetlands identified as piping plover habitat.</p>
NSO 11-10	<p>NO SURFACE OCCUPANCY STIPULATION</p> <p>No surface occupancy or use is allowed within one-quarter mile of wetlands identified as interior least tern habitat.</p>
NSO 11-13	<p>NO SURFACE OCCUPANCY STIPULATION</p> <p>No surface occupancy or use is allowed within developed recreation areas and undeveloped recreation areas receiving concentrated public use.</p>
TES 16-2	<p>ENDANGERED SPECIES ACT SECTION 7 CONSULTATION STIPULATION</p> <p>The lease area may now or hereafter contain plants, animals, or their habitats determined to be threatened, endangered, or other special status species. BLM may recommend modifications to exploration and development, and require modifications to or disapprove</p>

Stipulation Number	Stipulation Name/Brief Description
	proposed activity that is likely to result in jeopardy to proposed or listed threatened or endangered species or designated or proposed critical habitat.
TL 13-1	TIMING LIMITATION STIPULATION No surface use is allowed within crucial winter range for wildlife for the time period December 1 to March 31 to protect crucial white-tailed deer, mule deer, elk, antelope, moose, bighorn sheep, and sage grouse winter range from disturbance during the winter use season, and to facilitate long-term maintenance of wildlife populations. This stipulation does not apply to operation and maintenance of production facilities.
TL 13-3	TIMING LIMITATION STIPULATION No surface use is allowed from March 1 to June 15 in grouse nesting habitat within two miles of a lek. This stipulation does not apply to operation and maintenance of production facilities.
TL 13-4	TIMING LIMITATION STIPULATION No surface use is allowed within one-half mile of raptor nest sites which have been active within the past 2 years during the time period March 1 - August 1 to protect nest sites of raptors which have been identified as species of special concern. This stipulation does not apply to operation and maintenance of production facilities.

Appendix C

Reasonably Foreseeable Development Scenario Forecast for the October 21, 2014 Lease Sale

The Reasonably Foreseeable Development (RFD) scenario for the area of analysis is based on information contained in the MCFO RFD developed in 2005 and revised in 2012; it is an unpublished report that is available by contacting the MCFO. The MCFO RFD contains projections of the number of possible oil and gas wells that could be drilled and produced in the MCFO area and it is used to analyze the projected wells for the 18 nominated lease parcels, located in Richland, Roosevelt, McCone, Prairie, and Powder River counties, proposed for the October 21, 2014 lease sale.

The MCFO RFD contains projections of the number of possible oil and gas wells that could be drilled and produced within each of the three development potential areas specified as high, medium, and low potential areas. GIS was used to determine the number of projected new federal wells within each development potential by taking into consideration the same assumptions and methodology used to determine the MCFO RFD. To project the number of Federal wells on the nominated acres, the proportionate percentage of nominated lease acres within the high, medium, or low potential RFD area is multiplied by the respective total number of high, medium, or low potential projected wells. Where the number of wells in a parcel within a county had a projection of equal to or greater than 1 in 1000 (0.001) the well number was rounded up to one, if the number of wells projected in a parcel within a county had a projection of less than 1 in 1000 (.001) the well number was rounded to zero.

These well numbers are only an estimate based on the MCFO RFD which is based on USGS assessments, past and current development, resource expertise, and MBOCG feedback and data, and may change in the future if new technology is developed or new fields and formations are discovered.

High Potential

The 6,005 lease parcel acres located in McCone, Powder River, Richland, and Roosevelt Counties are in the area of High Potential (6,043,000 acres total) development. The RFD scenario forecasts a range of 856 to 1,711 oil wells and 1,004 to 2,009 gas wells in this development area. The range for federal wells is 197 to 394 oil wells and 231 to 462 gas wells. The High Potential lease parcels total approximately 6,005 acres, approximately 0.099 percent of the High Potential project area identified in the RFD.

Medium Potential

No lease parcels nominated lie within the area of Medium development potential.

Low Potential

The 1,599 lease parcel acres located in Prairie County are in the area of Low Potential (13,120,000 acres total) development. The RFD scenario forecasts a range of 325 to 650 oil wells and 382 to 764 gas wells in this development area. The range for federal wells is 197 to 394 oil wells and 231 to 462 gas wells. The Low Potential lease parcels total approximately 1,599 acres, approximately 0.012 percent of the Low Potential project area identified in the RFD.

Table 1. Nominated Lease Parcel Acres Offered within each County by Alternative

Alternative	Richland	Roosevelt	McCone	Prairie	Powder River
Alt A	0	0	0	0	0
Alt B	1148	200	40	1599	4617
Alt C	37	0	0	1039	80

Table 2. Projected Number of Wells within each County by Alternative

Alternative	Richland	Roosevelt	McCone	Prairie	Powder River
Alt A	0	0	0	0	0
Alt B	1	1	1	1	3
Alt C	1	0	0	1	1

Appendix D - Potential Surface Disturbance Associated with Federal Wells

The potential number of acres disturbed by federal wells and associated access road and utility corridor is shown in Table D-1. The potential acres of disturbance reflect acres typically disturbed by construction, drilling, and production activities, including infrastructure installation throughout the MCFO. Typical federal wells and associated access road and utility corridor acres of disturbance were used as assumptions for analysis purposes in this EA. The assumptions were not applied to Alternative A because the lease parcel would not be recommended for lease; therefore, no wells would be drilled or produced on the lease parcel and no surface disturbance would occur on those lands from exploration and development activities.

Estimated average acres of surface disturbance associated with well pad and access road/utility corridor are based on current disturbance of oil, gas, and CBNG APDs being permitted in the MCFO within the last five years.

Standard oil and gas practice typically combines access road and utility corridor (oil/gas/CBNG, water, and power) within the same corridor to minimize surface disturbance which requires a wider corridor but limits overall surface disturbance.

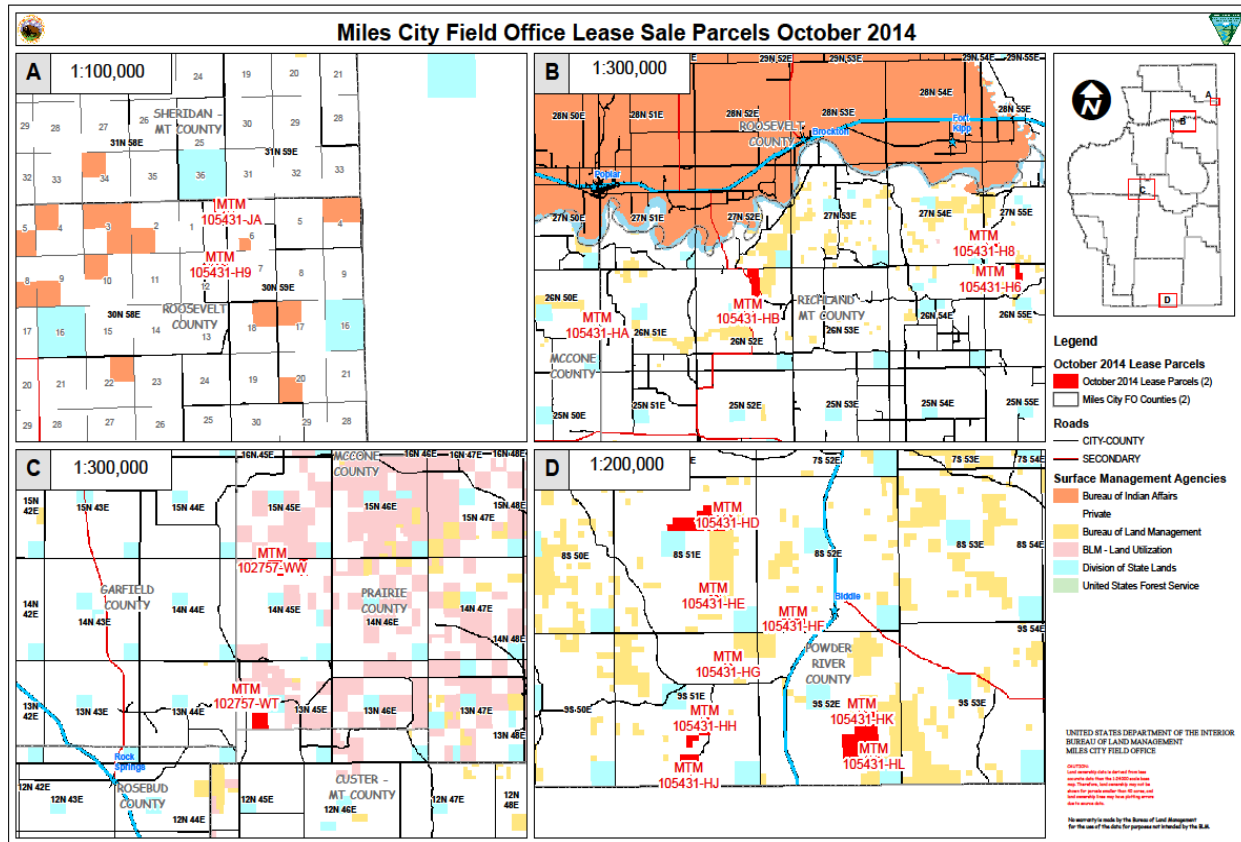
It is unknown how many wells would be drilled on multi-well pads; therefore to assist in determining acres of surface disturbance, it is assumed that one well would be drilled on one well pad.

Table D-1. Estimated Acres of Disturbance Associated with a Federal Well Pad and Access Road and Utility Corridor.

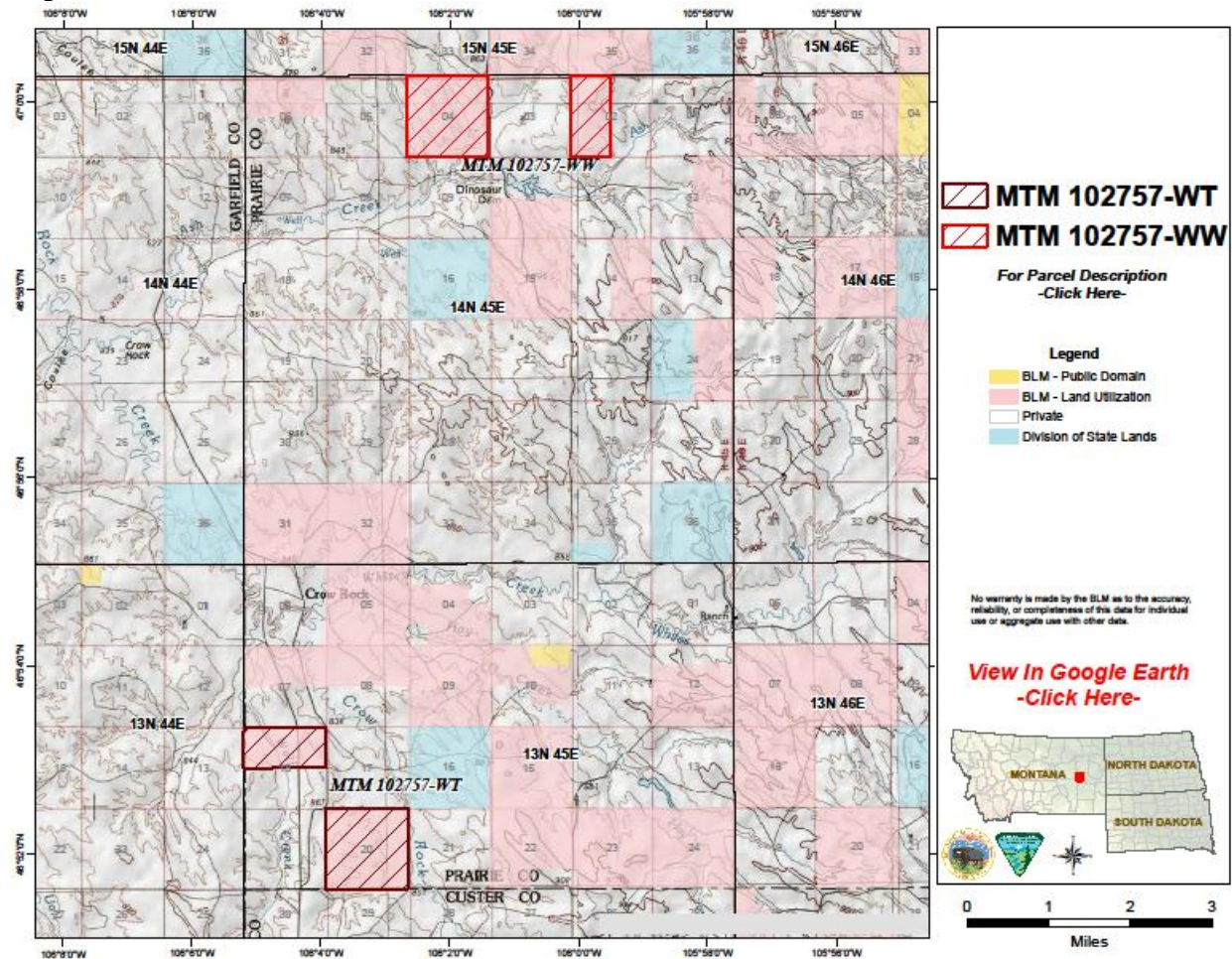
	Well Pad	Access Road/Utility Corridor	Total Disturbance
Oil	3.00	1.20	4.20
Gas	0.50	0.55	1.05
CBNG	0.25	0.55	0.80

Surface disturbance associated with major transportation lines, processing production areas, produced water management areas may not be included as part of the federal APD for permitting. It may be permitted and constructed in association with another APD; therefore, surface disturbance from associated infrastructure it is not included as acres of surface disturbance per well or access road/utility corridor listed in the table.

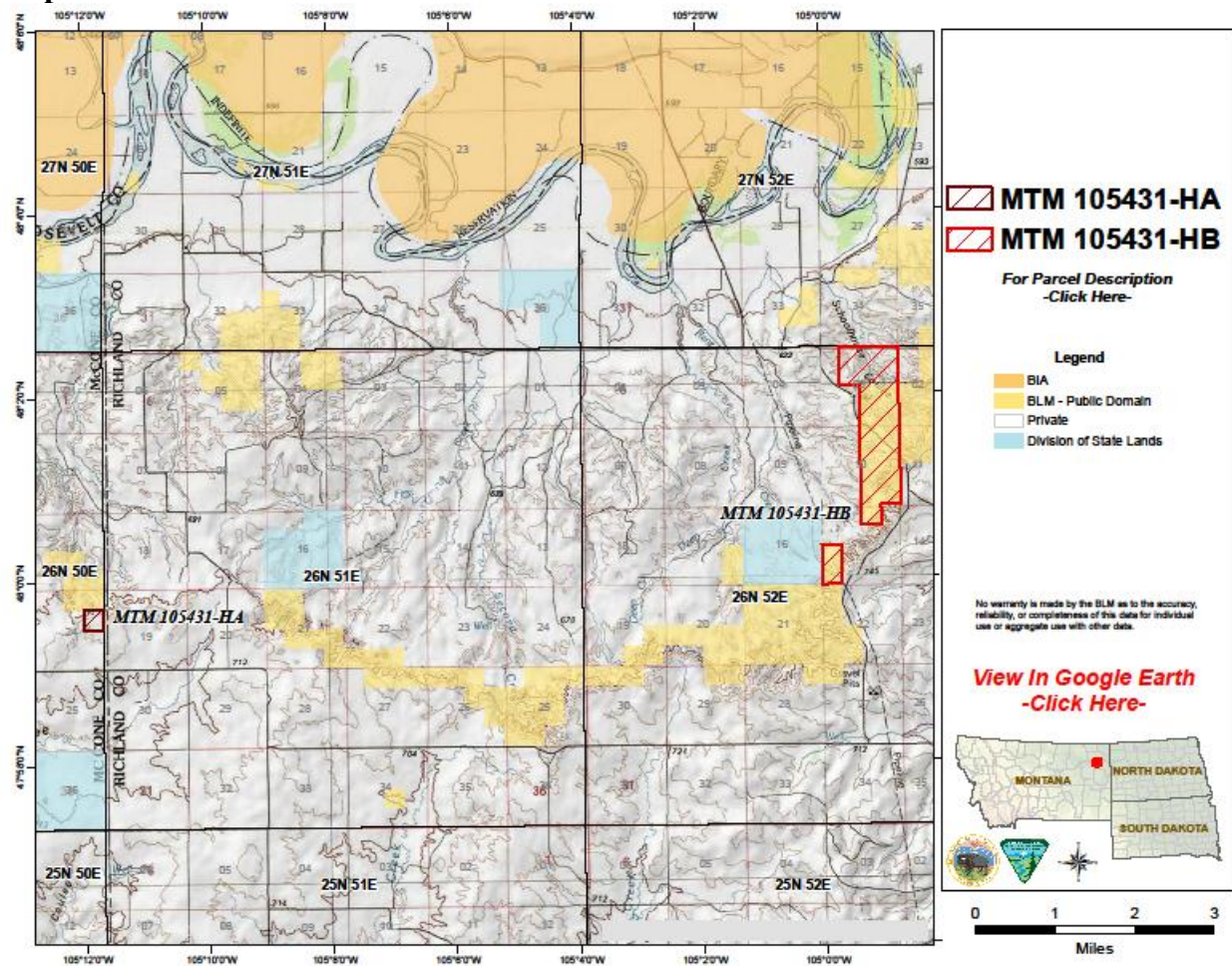
Map 1. All Nominated Lease Parcels



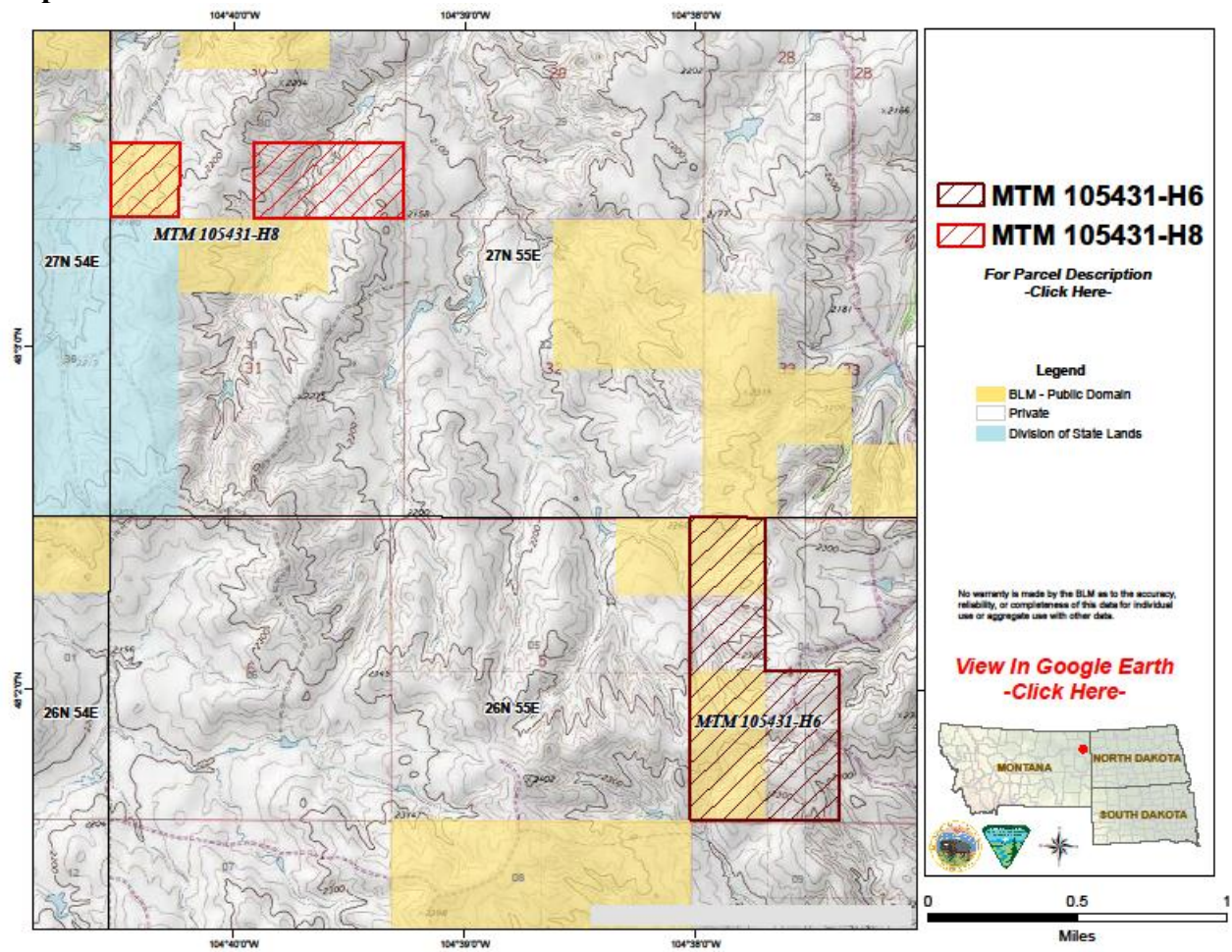
Map 2. Nominated Parcels MTM 102757-WT & MTM 102757-WW



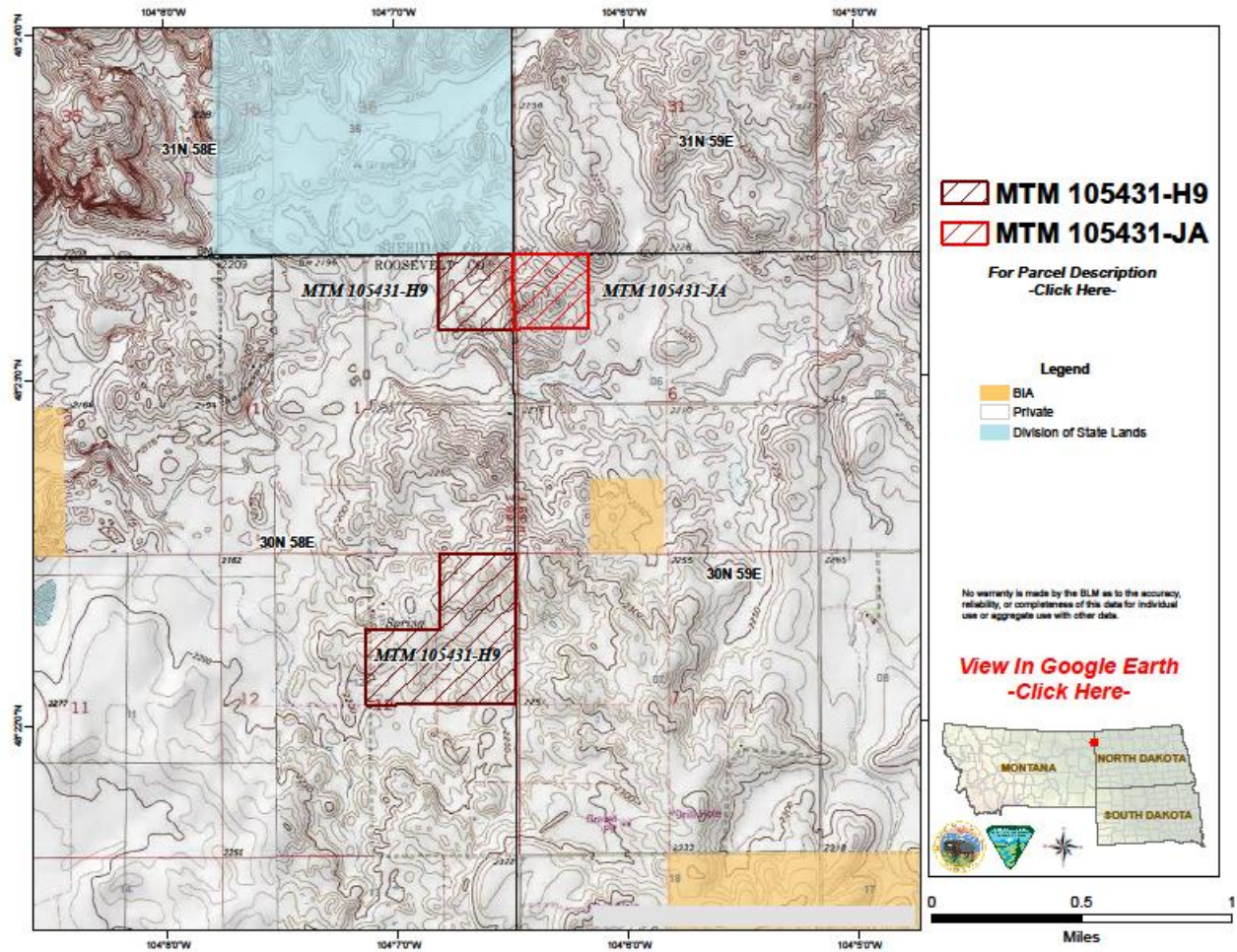
Map 3. Nominated Parcels MTM 105431-HA & MTM 105431-HB



Map 4. Nominated Parcels MTM 105431-H6 & MTM 105431-H8



Map 5. Nominated Parcels MTM 105431-H9 & MTM 105431-JA



Map 6. Nominated Parcels MTM 105431-HC, HD, HE, HF, HG, HH, HJ, HK, HL, & HM

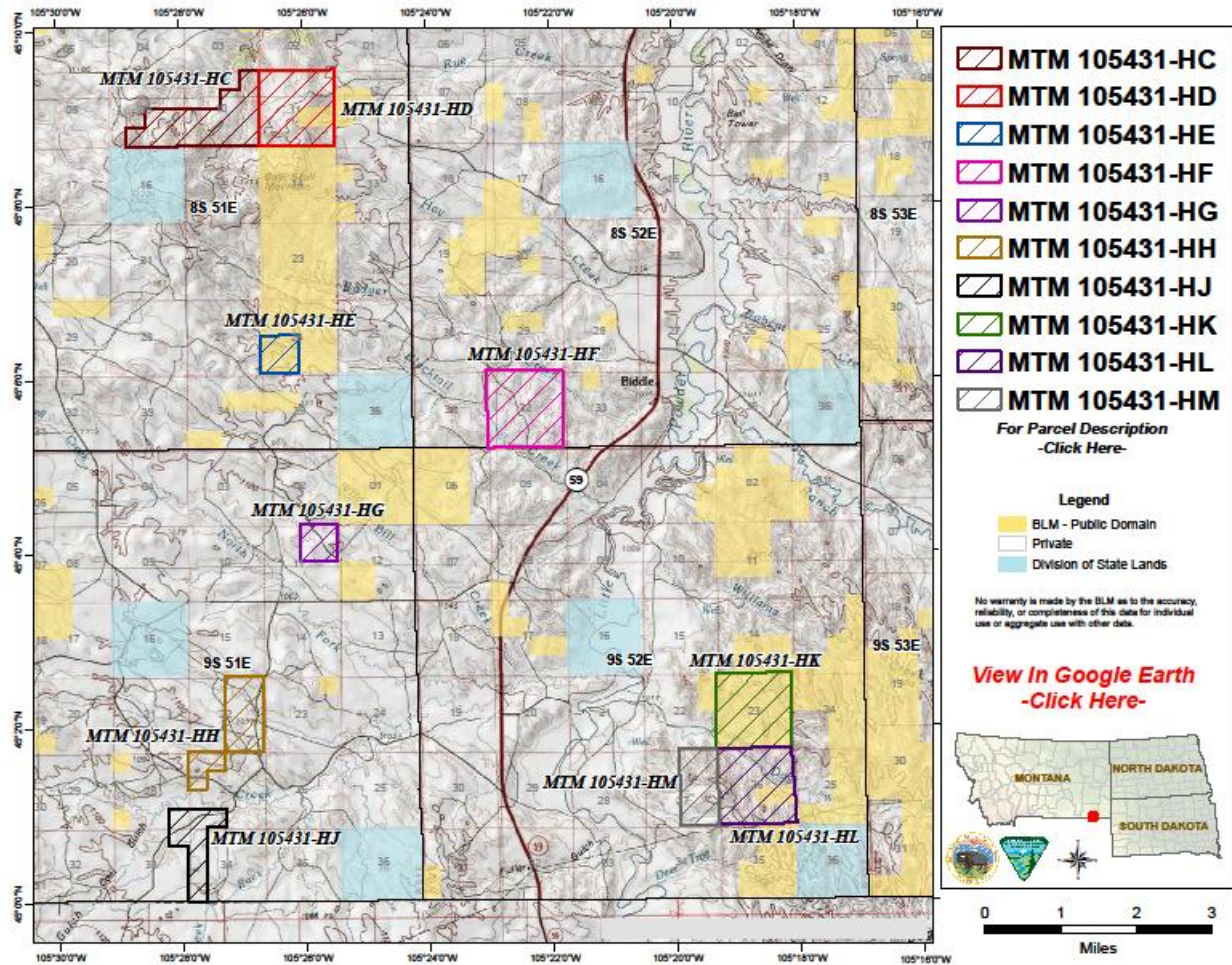


Exhibit 13

**U.S. Department of the Interior
Bureau of Land Management**

**Environmental Assessment
DOI-BLM-ID-B010-2014-0036-EA**

**Little Willow Creek
Protective Oil and Gas Leasing**

February 10, 2015

U.S. Department of the Interior
Bureau of Land Management
Four Rivers Field Office
3948 Development Avenue
Boise, ID 83705



Environmental Assessment # DOI-BLM-ID-B010-2014-0036-EA
Little Willow Creek Protective Oil and Gas Leasing

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Little Willow Creek Protective Oil and Gas Lease

1.0 Introduction

Leasing

The Mining and Minerals Policy Act of 1970 declares that it is the continuing policy of the Federal Government to foster and encourage private enterprise in the development of a stable domestic minerals industry and the orderly and economic development of domestic mineral resources. The Mineral Leasing Act of 1920, as amended, authorizes the Secretary of the Interior to lease federal oil and gas. The Bureau of Land Management (BLM) is the Interior agency delegated the authority to manage the United States' mineral resources. The BLM's oil and gas leasing programs are codified under 43 CFR 3100, in accordance with the authority of the Mineral Leasing Act of 1920, as amended, the Federal Land Policy and Management Act (FLPMA) of 1976, and the Energy Policy Act of 2005.

The decision as to which public lands and minerals are open for leasing and what leasing stipulations may be necessary is made during the land use planning process. Surface management/use for mineral extraction on non-BLM administered land overlaying federal minerals will be determined by the BLM in consultation with the appropriate surface management agency or the private surface owner at the time such surface use is proposed by the leaseholder or designated agent. Under the Mineral Lease Act, issuing oil and gas leases is a discretionary authority conveyed to the Secretary of Interior. In carrying out the mineral leasing authority conveyed through the Mineral Leasing Act, the BLM must comply with other applicable federal laws and regulations, including, but not limited to the Endangered Species Act, the National Historic Preservation Act, the Clean Water Act, the Clean Air Act, and the Energy Policy Act.

Offering federal mineral estate parcels for lease and subsequently issuing oil and gas leases are strictly administrative actions, which, in and of themselves, do not cause or directly result in any surface disturbance. Issuance of an oil and gas lease does convey to the lessee the exclusive right to use as much of the leased land as is reasonably necessary to explore for and extract oil and gas resources from the lease area, subject to the terms of the lease, including stipulations (43 CFR 3101.1-2 and 3101.1-3), regulations pertaining to oil and gas leasing, Onshore Orders, and with prior approval of the Authorized Officer. However, depending on lease stipulations, post-leasing activities may or may not result in impacts to surface resources. Only where stipulations or conditions do not preclude disturbance to surface resources is the action considered an irretrievable commitment of resources. The BLM may issue leases to protect the public interest when uncompensated drainage is occurring or may occur, provided the lease does not convey an irreversible or irretrievable commitment of resources.

As part of the lease issuance process, nominated parcels are reviewed against the appropriate land use plan, and stipulations are attached to mitigate any known environmental or resource conflicts that may occur on a given lease parcel. As stated above, on-the-ground impacts would potentially occur when a lessee applies for and receives approval to explore, occupy and/or drill

on the lease. The BLM cannot determine at the leasing stage whether or not a lease would actually be explored or developed.

Oil and gas leases are issued for a 10-year period and continue for so long thereafter as oil or gas is produced in paying quantities. If a lessee fails to produce oil and/or gas, does not make annual rental payments, does not comply with the terms and conditions of the lease, or relinquishes the lease, then ownership of the minerals leased revert back to the federal government and may be offered for lease again. Drilling wells on a lease is not permitted until the lessee or operator secures BLM's approval of a drilling permit and a surface use plan as specified in 43 CFR 3162.3-1 (Drilling applications and plans) and submits a reclamation bond. Subsequent well operations, such as re-drilling, deepening, repairing casing, plugging-back, performing non-routine fracturing jobs, etc. also require the prior approval of the authorized officer (43 CFR 3162.3-2).

Leasing in the Four Rivers Field Office

While parcels totaling over 180,000 acres of federal land in southwest Idaho have been nominated for competitive oil and gas leasing, BLM has to-date deferred leasing any lands until completion of the Four Rivers Resource Management Plan/EIS (FRMP). Currently, there are no federal oil and gas leases in the field office. The FRMP will replace the 1987 Cascade RMP which currently addresses leasing in the western portion of the Four Rivers Field Office. BLM is considering leasing in this isolated circumstance because of the federal mineral reserve drainage that may occur existing wells are put into production in sections with federal minerals in the Willow Field or on private lands in the proposed leasing area.

There are currently 15 wells that have been drilled on private or State leases in and/or near the Willow and Hamilton Fields and are capable of production, and three wells that have been approved but haven't been drilled. Four existing wells and two proposed wells are within 0.5 miles of federal mineral resources. Several of the wells are located in sections with federal mineral estate (Map 1). The existing wells are classified as "shut in pending a pipeline" indicating that they are capable of production.

The BLM determined the boundary of the proposed leasing area by including all lands with federal minerals in the industry-designated Willow Field, as well as those lands with federal minerals located in sections that are within one mile of a well that has been drilled or permitted. Only the lands with federal minerals would be leased within the proposed leasing area boundary. There are no lands with federal minerals in the Hamilton Field.

In November 2013, Alta Mesa Services, Inc., a company that is currently developing a newly discovered natural gas field, made application to the Idaho Oil and Gas Conservation Commission (IOGCC) to omit federal lands in T. 8 N., R. 4 W., Section 3, from a drilling unit it proposed in Section 3. If the federal minerals are omitted from the drilling unit and a producing well is drilled on the private lands (with private minerals) in Section 3, drainage of the federal mineral estate could occur. The opportunity to recover the underlying resource would be lost, and the federal government, acting on behalf of the American taxpayer, would be unable to collect royalties on the extracted mineral resources.

Leasing would protect the American taxpayers' correlative rights, and production royalties could be collected. The BLM considers Alta Mesa's application to the IOGCC to be evidence of potential drainage in Section 3. Lands that are otherwise unavailable for leasing may be leased if there is an imminent threat of drainage [see 43 CFR 3120.1-1(d)]. Because of this threat and the likelihood of IOGCC receiving more applications to omit the federal mineral estate in sections where wells have been drilled or proposed, BLM is considering leasing the federal mineral estate within this limited area at this time.

1.1 Need for and Purpose of Action

The purpose of this proposal is to protect the federal mineral resource from uncompensated drainage, and surface resources from potential damage, in and near the Willow Field, Payette County, Idaho. Drainage is defined as the migration of oil and gas in an underground reservoir, due to a pressure reduction caused by production from wells bottomed in the reservoir. Because oil and gas are fluids, they can flow underground across property boundaries. Subsurface (i.e. mineral) ownership boundaries are the same as those upon the surface, projected downward to the center of the earth. Sub-surface mineral rights in the U.S. generally belong to the owner of the surface land, unless they have been severed from the surface. According to an old common law concept termed the rule of capture, the first person to gain control over the resource (by extracting the resource from the ground) gains exclusive ownership over that resource. In this way, an operator may permissibly extract, or drain, oil and gas from beneath the land of another, if the extraction is lawfully conducted on his own property. The rule of capture gives land owners an incentive to pump out oil as quickly as possible by speeding up their operations or drilling multiple, closely spaced wells to capture, or drain, the oil or gas resource of their neighbors. Very dense drilling can result in dissipation of the pressure within a reservoir, and therefore incomplete extraction of the resource.

To mitigate this danger, many state governments have sought to supersede the rule of capture with conservation acts that enforce prorationing, pooling, and limits on density of drilling, to avoid physical waste, ensure maximum ultimate recovery, and to protect the correlative rights of neighboring owners. The correlative rights doctrine is a legal doctrine limiting the rights of landowners to an oil or gas reservoir to a reasonable share, based on the amount of land owned by each on the surface above. Correlative rights concepts such as pooling and unitization replace the rule of capture in those states that have them, thereby protecting the rights of mineral estate owners from drainage.

Uncompensated drainage means that federal mineral resources are being produced by wells on adjacent lands without compensation to the United States in the form of royalties that would otherwise be required if the federal mineral estate were leased under the Mineral Leasing Act, as amended. A prime responsibility of the BLM is to protect the United States from the loss of royalty that results from drainage (uncompensated drainage). For unleased lands, the objectives of BLM's drainage protection program may be accomplished by leasing and requiring the lessee to take protective measures to prevent uncompensated drainage of oil or gas from the lease.

This action is needed because natural gas wells have been or are proposed to be drilled on private land adjacent to BLM-administered lands and/or adjacent to lands where BLM owns only the subsurface mineral estate (referred to as split estate). The current and proposed wells in and north of the Willow Field constitute a threat, or potential threat, of uncompensated drainage to the federal mineral estate. Drilling has resulted in the discovery of commercial quantities of natural gas and natural gas condensate in the Willow and Hamilton fields, and those areas are being developed for commercial production. According to the current Idaho well spacing order, only one well can be drilled per 640-acre governmental section (IDAPA 20.07.02.330.02; IOGCC 2013a). The Idaho Department of Lands has approved drilling permit applications for several wells on private lands which would drain minerals reserved to the United States within the well spacing unit designated by the State of Idaho (IOGCC 2014).

In a September 4, 2014 IOGCC hearing, the commission voted 4-1 to reconsider a request by Alta Mesa to omit federal mineral resources. If federal minerals are omitted from a drilling unit, BLM would be unable to collect the royalties it is due for its proportionate share of production from the drilling unit; therefore, the BLM considers these resources threatened by uncompensated drainage. While 43 CFR 3162.2-2 offers several protective measures BLM may take to avoid uncompensated drainage on unleased lands besides leasing, they require the cooperation of the owner-of-interest in the producing well. BLM has offered several times to enter into a communitization or compensatory royalty agreement; however, Alta Mesa has refused to do so, leaving leasing as the only alternative to address drainage.

1.2 Decision to Be Made

The responsible official will decide whether to recommend that the BLM Idaho State Office offer lands in the proposed lease area and which, if any, stipulations and/or notices should be attached to the leases.

1.3 Summary of Proposed Action

The BLM proposes to offer five parcels (totaling 6,349 acres; Map 2) at a spring 2015 competitive oil and gas lease sale. Stipulations and lease notices would apply on BLM-administered surface and subsurface in the lease area. The offering and subsequent issuance of oil and gas leases is strictly an administrative action, which, in and of itself, would not cause or directly result in any surface disturbance.

1.4 Location and Setting

The proposed 15,644-acre Little Willow Creek oil and gas lease area is located 4-12 miles east of Payette, Idaho (Map 1). The topography is characterized by gently rolling hills. Vegetation is dominated by annual and perennial grass with occasional shrub stands. Rural homes and agricultural fields are primarily associated with Little Willow Creek.

In the proposed lease area, only 6% of surface lands are BLM-administered and the remaining are privately owned; however, the BLM administers 41% of the subsurface mineral estate. Two oil and gas fields to the south have been designated by oil and gas developers. The Willow Field overlies a portion of the Little Willow Creek proposed lease area and currently has eight oil and

gas wells. Further south, the Hamilton Field has six wells. Most wells in the area are classified as shut in pending a pipeline (IOGCC 2014).

1.5 Conformance with Applicable Land Use Plan

Leasing is in conformance with the 1988 Cascade Resource Management Plan (CRMP) which makes 456,289 acres (94% of area) available for leasable mineral exploration and development (CRMP Record of Decision page 3). The proposed lease parcels are within the area determined available for leasable mineral exploration and development. The CRMP directs the BLM to manage geological, energy, and minerals resources on the public lands so that significant scientific, recreational, ecological and educational values will be maintained or enhanced. Generally, the public lands are available for mineral exploration and development, subject to applicable regulations and Federal and State laws. The CRMP states that: “Approval of an application for lease is subject to an environmental analysis and may include stipulations to protect other resources.” Additional NEPA documentation is needed prior to leasing to address new circumstances or information bearing on the environmental consequences of leasing that was not considered within the broad scope analyzed in the CRMP Environmental Impact Statement.

1.6 Relationship to Statutes, Regulations, and Other Requirements

This EA was prepared in accordance with the National Environmental Policy Act of 1969 (NEPA) and in compliance with all applicable laws and regulations, including Council on Environmental Quality (CEQ) regulations (40 CFR Parts 1500-1508), U.S. Department of the Interior (DOI) requirements (Department Manual 516, Environmental Quality), and/or other federal statutes and executive orders.

Other applicable Federal laws to which the lessee must comply include but are not limited to, the following:

Leasable Minerals

It is BLM policy, as derived from various laws, including the Mineral Leasing Act of 1920 (MLA) and the Federal Land Policy and Management Act of 1976 (FLPMA), to make mineral resources available for disposal and to encourage development of mineral resources to meet national, regional, and local needs. Ensuring that the federal mineral estate is protected from uncompensated drainage of fluid mineral resources is a basic BLM function. 43 CFR 3100.2-1 states “Upon a determination by the authorized officer that lands owned by the U.S. are being drained of oil or gas by wells drilled on adjacent lands . . . Such lands may also be offered for lease in accordance with part 3120 of this title.” 43 CFR 3120.1-1 states that “All lands available for leasing shall be offered for competitive bidding under this subpart, including but not limited to . . . (d) Lands which are otherwise unavailable for leasing but which are subject to drainage (protective leasing).”

Any purchaser of a federal oil and gas lease is required to comply with all applicable federal, state, and local laws and regulations, including obtaining all necessary permits required prior to the commencement of project activities.

Environmental Quality

Clean Water Act of 1972 (33 U.S.C. §1251 et seq.): Regulates surface water discharges and storm-water runoff. Section 313 requires federal agencies be in compliance with all federal, state, interstate, and local requirements. In Idaho, the Idaho Department of Environmental Quality (IDEQ) implements the Clean Water Act. Additionally, the IDEQ develops total maximum daily loads (TMDLs) for water bodies.

Safe Drinking Water Act of 1974 as amended: Authorizes the U.S. Environmental Protection Agency (EPA) to set national health-based standards for drinking water to protect against both naturally-occurring and man-made contaminants that may be found in drinking water. The EPA, IDEQ, and others work together to make sure that the standards are met.

Clean Air Act of 1970 as amended (42 U.S.C. §7401 et seq.): Sets rules for air emissions from engines, gas processing equipment and other sources associated with drilling and production activities.

Special Status Species

Endangered Species Act (ESA) of 1973 as amended (16 USC 1531): Section 7 of the ESA outlines the procedure for federal interagency cooperation to conserve federally listed species and their designated habitats. Section 7(a) (2) of the ESA states that each federal agency shall, in consultation with Secretary, ensure that any action it authorizes, funds, or carries out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of a listed species' habitat within the project area.

Special Status Species Management Manual for the Bureau of Land Management (BLM Manual 6840): National policy directs BLM State Directors to designate sensitive species in cooperation with the state fish and wildlife agency. This manual establishes policy for management of species listed or proposed for listing pursuant to the ESA and Bureau sensitive species that are found on BLM-administered lands; this policy is to conserve and to mitigate adverse impacts to sensitive species and their habitats. Where relevant to the activities associated with this action, effects to special status species are analyzed in this EA.

Migratory Bird Treaty Act, Executive Order 13186, and BLM Memorandum of Understanding WO-230-2010-04 (between BLM and US Fish and Wildlife Service [USFWS]): Federal agencies are required to evaluate the effects of proposed actions on migratory birds (including eagles) pursuant to the *National Environmental Policy Act of 1969* (NEPA) “or other established environmental review process;” and restore and enhance the habitat of migratory birds, as practicable. Federal agencies are also required to identify where unintentional take reasonably attributable to agency actions is having, or is likely to have, a measurable negative effect on migratory bird populations. With respect to those actions so identified, the agency shall develop and use principles, standards, and practices that will lessen the amount of unintentional take,

developing any such conservation efforts in cooperation with the Service. Effects to migratory birds are analyzed in this EA.

Bald and Golden Eagle Protection Act of 1940 as amended (16 USC 668-668d): This act provides for the protection of bald and golden eagles by prohibiting, except under certain specified conditions, the taking, possession and commerce of such birds. Agencies are required to evaluate: 1) whether take is likely to occur from activities associated with the proposed activity and 2) the direct, indirect, and cumulative impacts the proposal may have on the ability to meet the preservation standard of the Act that the USFWS has interpreted to mean “compatible with the goal of stable or increasing breeding populations.” Effects to bald and golden eagles are analyzed in this EA.

Cultural Resources

Idaho BLM has the responsibility to manage cultural resources on public lands pursuant to the National Historic Preservation Act of 1966 (as amended), the 2012 Programmatic Agreement Among the Bureau of Land Management, the Advisory Council on Historic Preservation, and the National Conference of State Historic Preservation Officers and the State Protocol Agreement Between the Idaho State Director of the BLM and the Idaho State Historic Preservation Officer (1998) and other internal policies.

Social and Economic

Executive Order 12898 (February 1994): Federal agencies are directed to “make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations,” including tribal populations. The accompanying Presidential Memorandum emphasizes the importance of using the NEPA review process to promote environmental justice.

1.7 Scoping and Development of Issues

Scoping

BLM began scoping for the Little Willow Creek lease sale on July 8, 2014 when the Four Rivers Field Manager sent a scoping packet and/or letter to all land owners with property in or adjacent to the Little Willow Creek proposed lease area and to the Four Rivers Field Office’s interested public mailing list seeking scoping comments on the lease proposal. BLM also activated a web page on the BLM NEPA Register to make scoping and informational materials available to the public. The webpage can be reviewed at: <https://www.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=renderDefaultPlanOrProjectSite&projectId=39064&dctmId=0b0003e8806d22d8>.

On Thursday July 17, 2014 the BLM hosted a public meeting at the Payette County Courthouse. BLM answered questions and accepted comments at the meeting and provided an address and website to send in additional scoping comments about the proposed leasing. Approximately 45 people attended the meeting and 12 individuals and organizations provided scoping comments. Many of the issues were outside the scope of the leasing decision. The public was primarily

concerned with drilling which would be analyzed in a subsequent NEPA document if an Application for Permit to Drill (APD) is received by BLM (Appendix 1). The intent of BLMs scoping effort was to identify issues related to the proposed leasing.

Issues Development

Issues may be defined as a point or matter of discussion, debate, or dispute about a proposed action based on the potential environmental effects (BLM Handbook H-1790-1). Issues are concerns directly or indirectly caused by implementing the proposed action; these are used to develop alternatives to the proposed action. Relevant public comments and issues were used in the development of this EA, including those received in response to the Scoping Document mailed July 8, 2014. Comments not considered issues to analyze in this EA are ones that are: 1) outside the scope of the proposed action and thus irrelevant to the decision being made; 2) already decided by law, regulation, RMP, or other higher level decision; 3) conjectural and not supported by scientific or factual evidence; or 4) not necessary for making an informed decision. The following issues were identified from comments and scoping letters received during the scoping effort:

1. Leasing could indirectly impact air quality in the proposed lease area if exploration and development occur.
2. Leasing could indirectly impact water quality in the proposed lease area if exploration and development occur.
3. Leasing could indirectly pollute ground water in the proposed lease area if exploration and development wells require hydraulic fracturing (fracking).
4. Leasing could indirectly impact sensitive plant species in the proposed lease area if exploration and development occur.
5. Leasing could indirectly impact sensitive wildlife species in the proposed lease area if exploration and development occur.

These issues are addressed in Section 3.0. Although development in the Willow and Hamilton fields has not indicated the need for substantial fracking (Johnson et. al. 2013), the issue is addressed primarily in Water Resources (Section 3.5). The IDT also analyzed the indirect effects of leasing on the following resources: soils, vegetation, cultural resources, recreation, visual resources, lands and realty, livestock management, minerals, and social and economics.

2.0 Description of the Alternatives

2.1 Alternative A - No Federal Mineral Estate Leasing/Continue Present Management

The federal mineral estate in a 15,644 acre area in Payette County, including 996.85 (997) acres of BLM-administered lands and 5,352.35 (5,352) acres of split estate, would not be offered for lease. Development of State and private leases could occur in the area; however, the federal mineral estate would not be available at least until the FRMP is completed. State (Appendix 2) or other stipulations developed by the lessor and lessee would apply to other leases.

2.2 Alternative B – Leasing Federal Mineral Estate with No Surface or Subsurface Occupancy Stipulations

The federal mineral estate in a 15,644 acre area in Payette County, including 997 acres of BLM-administered lands and 5,352 acres of split estate, would be offered for lease in up to five parcels^A (Table 1, Map 2, Appendix 3).

Table 1. Mineral estate acreages by parcel, surface, and subsurface ownership, proposed Little Willow Creek oil and gas leasing area, Payette County, Idaho.

Parcel	Federal Mineral Estate ¹			Other Mineral Estate ²		Total
	Federal/Federal	Private/Federal	Total	Private/Private	Private/State	
A	212	1,536	1,748	3,811	0	5,549
B	237	312	549	1,353	0	1,903
C	235	1,140	1,374	1,142	0	2,516
D	274	1,311	1,585	1,186	394	3,165
E	39	1,052	1,091	1,313	98	2,502
Total	997	5,352	6,349	8,799	492	15,644

¹ Acreages presented in this table and throughout the document are rounded to the nearest acre. More accurate figures would be developed if a lease is offered.

² The BLM has no control over these resources. The values are provided strictly for informational purposes.

The following stipulations would apply to the federal mineral estate:

No Surface Occupancy (NSO) –1: Surface occupancy and use on BLM-administered and split estate lands would be prohibited until the Four Rivers Resource Management Plan (FRMP) is finalized.

No Sub-surface Occupancy (NSSO) –1: Subsurface occupancy and use on federal mineral estate lands would be prohibited until the FRMP is finalized.

Upon finalization of the FRMP, the leases would be modified by replacing NSO-1 and NSSO-1 with stipulations consistent with the FRMP. Development of State and private leases would be as described in Section 2.1; however, drainage of the federal mineral estate would be allowed and typical royalties would be applied.

^A Because an oil and gas lease cannot be larger than 2,560 acres (43 CFR 3120.2-3), the 6,352-acre federal mineral estate was divided into smaller parcels. BLM has the discretion to parcel the lands in any configuration. During public scoping, at least one split estate land owner expressed a desire to bid on parcels to which he/she owns the surface estate. BLM has addressed the land owner's concern by making the leases smaller, and by dividing the federal mineral estate in a manner that minimizes the number of split estate landowners on a single lease (the only exception to this is Parcel A, which has multiple split estate landowners, but lies entirely within the industry-designated Willow Field).

2.3 Alternative C - Leasing Federal Mineral Estate with Cascade RMP Stipulations and Additional Lease Notices

The federal mineral estate in a 15,644 acre area in Payette County, including 997 of BLM-administered lands and 5,352 acres of split estate, would be offered for lease in up to five parcels (Table 1, Map 2, Appendix 3). The leases would be subject to standard lease terms and the following stipulations associated with listed species (S-1) and cultural resources (S-2), applicable CRMP stipulations, and lease notices. Lease notices were developed for sensitive resources that were not addressed in the CRMP. Development of State and other leases would be as described in Section 2.1. The following stipulations and lease notices would apply where appropriate (Appendix 3):

Freshwater Aquatic Habitat

Controlled Surface Use (CSU) -1: Surface occupancy and use would be prohibited within 500 feet from the edge of reservoirs, ponds, streams, wetlands, and riparian habitat. Introduction of chemical toxicants or sediments to riparian areas as a result of exploration or production would not be allowed.

CSU-2: A minimum 100 foot riparian buffer zone would be provided from the edge of any riparian habitat to protect riparian vegetation, fisheries, and water quality. The following activities would be generally excluded: new road construction that parallels streams. Best management practices would be used when construction cannot be avoided.

Special Status Plant Species

CSU-3: Occupancy and use, including surface and subsurface rights-of-way, would be prohibited in Type 1-4 special status plant element occurrences.

Big Game Range^B

CSU-4: No surface use would be allowed in crucial winter range from November 15 to May 15 or crucial antelope fawning range between May 1 and June 30.

Sensitive Wildlife Species

CSU-5: No surface use would be allowed within a 0.75 mile radius of ferruginous hawk or Swainson's hawk nests from March 15 to June 30.

CSU-6: No surface use would be allowed within a 0.75 mile radius of an osprey nest from April 15 to August 31.

CSU-7: No surface use would be allowed within a 0.25 mile radius of a burrowing owl nest from March 15 to June 30.

^B From the CRMP: "Those areas where big game animals have demonstrated a definite pattern of use each year or an area where animals tend to concentrate in significant numbers (from Interagency Guidelines for Big Game Range Investigation-Idaho Department of Fish & Game, Bureau of Land Management, U.S. Forest Service)." For the purposes of this action, the BLM worked in cooperation with IDFG to delineate winter ranges using current animal distribution data.

Wildlife Species of Concern

CSU-8: No surface use would be allowed within a 0.75 mile radius of a golden eagle nest from February 1 to June 30.

CSU-9: No surface use would be allowed within a 0.75 mile radius of a prairie falcon nest from March 15 to June 30.

CSU-10: No surface occupancy would be allowed within a 0.5 mile radius of a heron rookery.

Fragile Soils

Lease Notice (LN) -1: The lessee is hereby notified that special location, design and construction mitigation measures may be required to minimize, to the extent possible, the potential long-term and short-term adverse impacts of oil and gas operations within fragile soils, and to avoid them wherever there is a practicable alternative.

Fragile soil areas, in which the performance objective would be enforced, are defined as follows:

- 1) Areas rated as highly or severely erodible by wind or water, as described by the National Cooperative Soil Survey for Payette County or as described by on-site inspection.
- 2) Areas with slopes $\geq 30\%$, if they also have one of the following soil characteristics:
 - a. a surface texture that is sand, loamy sand, very fine sandy loam, fine sandy loam, silty clay or clay;
 - b. a depth to bedrock < 20 inches;
 - c. an erosion condition that is rated as poor; or
 - d. a K-factor > 0.32 .

Floodplain Management

LN-2: The lessee is hereby notified that special location, design and construction mitigation measures may be required to minimize, to the extent possible, the potential long-term and short-term adverse impacts of oil and gas operations within the 100-year floodplain associated with occupancy and modification of the floodplain, and to avoid direct and indirect floodplain development wherever there is a practicable alternative. Under Executive Order 11988: Floodplain Management; the BLM is required to restore and preserve the natural and beneficial values served by floodplains for actions related to federal activities and programs affecting land use.

Endangered Species (Mandatory)

Stipulation (S) -1: The lease area may now or hereafter contain plants, animals, or their habitats determined to be threatened, endangered, or other special status species. BLM may recommend modifications to exploration and development proposals to further its conservation and management objective to avoid BLM-approved activity that will contribute to a need to list such a species or their habitat. BLM may require modifications to or disapprove proposed activity that is likely to result in jeopardy to the continued existence of a proposed or listed threatened or endangered species or result in the destruction or adverse modification of a designated or proposed critical habitat. BLM will not approve any ground-disturbing activity that may affect any such species or critical habitat until it completes its obligations under applicable

requirements of the Endangered Species Act as amended, 16 U.S.C. § 1531 et seq., including completion of any required procedure for conference or consultation.

Special Status Mammals

LN-3: The lease may, in part or in total, contain important southern Idaho ground squirrel (SIDGS), a candidate species, and pygmy rabbit habitats as identified by the BLM, either currently or prospectively. The operator may be required to implement specific measures to reduce impacts of oil and gas operations on SIDGS populations and habitat quality. Such measures shall be developed during the application for permit to drill on-site and environmental review process and will be consistent with the lease rights granted. Measures may include (in order of priority):

1. Avoid areas occupied by SIDGS and pygmy rabbits.
2. When oil and gas facilities are deemed necessary within unoccupied SIDGS or pygmy rabbit habitat, minimize pad size, road width, and the size of other disturbed areas.
3. New construction of roads, pipelines, and rights-of-way would be planned to minimize the effects of fragmenting wildlife habitat.
4. Restore unneeded areas to native or other appropriate vegetation (shrubs, perennial grasses, and forbs as identified by the SIDGS Working Group) immediately upon vacancy of temporary use sites or permanent closure of well sites to provide forage for nearby SIDGS.
5. Construct power transmission lines outside of SIDGS occupied habitat (including a 0.25-mile buffer) whenever possible. If transmission lines are deemed necessary through or within 0.25 miles of SIDGS colonies, locate poles outside of active burrow systems and consider 1) burying transmission lines, or 2) installing raptor anti-perching devices on transmission lines.

Migratory Birds and Raptors

LN-4: The Operator is responsible for compliance with provisions of the Migratory Bird Treaty Act by implementing one of the following measures: a) avoidance by timing - ground disturbing activities would not occur from April 15 to July 15; b) habitat manipulation - render proposed project footprints unsuitable for nesting prior to the arrival of migratory birds (blading or pre-clearing vegetation must occur prior to April 15 within the year and area scheduled for activities between April 15 and July 15 of that year to deter nesting; or c) survey-buffer-monitor surveys would be conducted by a BLM approved biologist within the area of the proposed action and a 300 foot buffer from the proposed project footprint between April 15 to July 15 if activities are proposed within this timeframe. If nesting birds are found, activities would not be allowed within 0.1 miles of nests until after the birds have fledged. If active nests are not found, construction activities must occur within 7 days of the survey. If this does not occur, new surveys must be conducted. Survey reports would be submitted to the appropriate BLM Office.

CSU-11: No surface occupancy would be allowed within 1 mile of an active bald eagle or peregrine falcon nest. No surface use would be allowed from December 1 and March 31 where wintering bald eagles or peregrine falcons occur.

Water Quality

LN-5: The operator may be required to implement specific measures to reduce impacts of oil and gas operations on water quality and quantity. Such measures shall be developed during the application for permit to drill on-site and environmental review process and will be consistent with the lease rights granted.

Cultural Resources (Mandatory)

S-2: This lease may be found to contain historic properties and/or resources protected under the National Historic Preservation Act (NHPA), American Indian Religious Freedom Act, Native American Graves Protection and Repatriation Act, E.O. 13007, or other statutes and executive orders. The BLM would not approve any ground disturbing activities that may affect any such properties or resources until it completes its obligations under applicable requirements of the NHPA and other authorities. These obligations may include a requirement that you provide a cultural resources survey conducted by a professional archaeologist approved by the State Historic Preservation Office (SHPO). If currently unknown burial sites are discovered during development activities associated with this lease, these activities must cease immediately, applicable law on unknown burials will be followed and, if necessary, consultation with the appropriate tribe/group of federally recognized Native Americans will take place. The BLM may require modification to exploration or development proposals to protect such properties, or disapprove any activity that is likely to result in adverse effects that cannot be successfully avoided, minimized or mitigated.

LN-6: The Surface Management Agency is responsible for assuring that the leased lands are examined to determine if cultural resources are present and to specify mitigation measures.

Lands and Realty

LN-7: Land Use Authorizations incorporate specific surface land uses allowed on BLM-administered lands by authorized officers and those surface uses acquired by BLM on lands administered by other entities. These BLM authorizations include rights-of-way, leases, permits, conservation easements, and recreation and public purpose leases and patents.

Paleontological Resources

CSU-12: No surface occupancy would be allowed on sites with known paleontological values. Surface rights-of-way would be routed to avoid paleontological resources.

LN-7: This lease has is located in geologic units rated as being moderate to very high potential for containing significant paleontological resources. The locations meet the criteria for Class 3, 4 and/or 5 as set forth in the Potential Fossil Yield Classification System, WO IM 2008-009, Attachment 2-2. The BLM is responsible for assuring that the leased lands are examined to determine if paleontological resources are present and to specify mitigation measures. Guidance for application of this requirement can be found in WO IM 2008-009 dated October 15, 2007, and WO IM 2009-011 dated October 10, 2008. Prior to undertaking any surface-disturbing activities on the lands covered by this lease, the lessee or project proponent shall contact the BLM to determine if a paleontological resource inventory is required. If an inventory is required, the lessee or project proponent will complete the inventory subject to the following:

- The project proponent must engage the services of a qualified paleontologist, acceptable to the BLM, to conduct the inventory.
- The project proponent will, at a minimum, inventory a 10-acre area or larger to incorporate possible project relocation which may result from environmental or other resource considerations.

A paleontological inventory may identify resources that may require mitigation to the satisfaction of the BLM as directed by WO IM 2009-011 including possible project relocation which may result from environmental or other resource considerations.

2.4 Additional Considerations for Alternatives B-C

For split estate portions of the lease area, the BLM provided courtesy notification to private landowners that their lands are considered in this NEPA analysis and would be considered for inclusion in an upcoming lease sale. If any activity were to occur on such split estate parcels, the lessee and/or operator would be responsible for adhering to BLM requirements as well as formulating and reaching an agreement with the private surface landowners regarding access, surface disturbance, and reclamation (Onshore Oil and Gas Order No. 1). Standard lease terms, stipulations, conditions, and operating procedures would apply to these parcels (43 CFR 3101 and 3160 and 3162).

Standard operating procedures, best management practices, conditions of approval (COA), and lease stipulations could change over time to meet overall RMP and BLM policy objectives. The COA's would be attached to permits for oil and gas lease operations to address site-specific concerns or new information not previously identified in this environmental assessment process. In some cases new lease stipulations may need to be developed, and these types of changes may require an RMP amendment. For example, if climate change results in hotter and drier conditions, RMP objectives would be unreachable under current management. In this situation, management practices might need to be modified to continue meeting overall RMP management objectives. An example of a climate related modification is the imposition of additional conditions of approval to reduce surface disturbance and implement more aggressive dust treatment measures. Both actions reduce fugitive dust, which would otherwise be exacerbated by the increasingly arid conditions that could be associated with climate change.

Oil and gas leases would be issued for a 10-year period and would continue for as long thereafter as oil or gas is produced in paying quantities. If a lessee fails to produce oil and gas, does not make annual rental payments, does not comply with the terms and conditions of the lease, or relinquishes the lease, ownership of the minerals leased would revert back to the federal government, and the lease could be resold.

Well drilling on a lease would not be permitted until the lease owner or operator secures approval of a drilling permit and a surface use plan specified at 43 CFR 3162.

Drainage

LN-A: Parts of this lease may potentially be subject to drainage by wells located on adjacent private lands. The lessee shall, within 6 months of the drilling and completion of any productive well on the adjacent private lands, submit for approval by the authorized officer:

1. Plans for protecting the lease from drainage (43 CFR § 3162.2-3). The plan must include either (a) a completed Application for Permit to Drill for each of the necessary protective wells, or (b) a proposal for inclusion in a unitization or communitization agreement for the affected portion of the lease. Any agreement should provide for an appropriate share of the production from the offending well to be allocated to the lease; or
2. Engineering, geologic and economic data to demonstrate to the authorized officer's satisfaction that no drainage has occurred or is occurring and/or that a new protective well(s) would have little or no chance of production sufficient to yield a reasonable rate of return in excess of the costs of drilling, completing and operating the well.

If no plan, agreement, or data is submitted and drainage is determined to be occurring, compensatory royalty will be assessed. Compensatory royalty will be assessed on the first day following expiration of the 6-month period, and shall continue until a protective well has been drilled and placed into production status, or until the offending well ceases production, whichever occurs first. The lessee shall be obligated to pay compensatory royalty to the Office of Natural Resources Revenue (ONRR) at a rate to be determined by the BLM authorized officer.

Split Estate

LN-B: Portions of the surface estate of this lease are privately owned (i.e. split estate lands). While the Federal mineral lessee has the right to enter the property for necessary purposes related to lease development, the lessee is responsible for making arrangements, formalized in a Surface Use Agreement, with the surface owner prior to entry upon the lands. Lessee is hereby informed that the United States will not participate as a third party in negotiations between the lessee and the surface owner. Any agreement reached between the lessee and the surface owner(s) will not be binding on the United States.

Prior to submitting an Application for Permit to Drill (APD) for BLM's approval, lessee is required to submit the name, address, and phone number of the surface owner, if known, in its APD. The lessee must also make a good faith effort to provide a copy of their Surface Use Plan of Operations to the surface owner. After the APD is approved, the operator must make a good faith effort to provide a copy of the Conditions of Approval to the surface owner.

The lessee will be required to certify to the BLM in writing that: (1) It made a good faith effort to notify the surface owner before entry; and (2) That a Surface Use Agreement with the surface owner has been reached, or that a good faith effort to reach an agreement failed. If no agreement can be reached with the surface owner, the lessee must submit an adequate bond (minimum of \$1,000) to the BLM, for the benefit of the surface owner, sufficient to pay for loss or damages. The surface owner has the right to appeal the sufficiency of the bond.

Once a parcel is leased, the lessee has the right to explore for and develop oil and gas resources, subject to standard lease terms and special stipulations pertaining to the conduct of operations. The conduct of operations by the lessee on all parcels would be subject to the following terms from the back of the standard lease form, which state:

“Conduct of Operations (SF-3100-11, Section 6)

Lessee shall conduct operations in a manner that minimizes adverse impacts to the land, air, and water, to cultural, biological and other resources, and to uses or users. Lessee shall take reasonable measures deemed necessary by the lessor to accomplish the intent of this section. To the extent consistent with lease rights granted, such measures may include, but not limited to, modification to siting or design of facilities, timing of operations, and specification of interim and final reclamation measures. Lessor reserves the right to continue existing uses and to authorize future uses upon or in leased lands, including the approval of easements or right-of-way. Such uses shall be conditioned so as to prevent unnecessary or unreasonable interference with rights of lessee.

Prior to disturbing the surface of the leased lands, lessee shall contact lessor to be apprised of procedures to be followed and modifications or reclamation measures that may be necessary. Areas to be disturbed may require inventories or special studies to determine the extent of impacts to other resources. Lessee may be required to complete minor inventories or short-term special studies under guidelines provided by lessor. If in the conduct of operations, threatened or endangered species, objects of historic or scientific interest, or substantial unanticipated environmental effects are observed, lessee shall immediately contact lessor. Lessee shall cease any operations that would result in destruction of such species or objects.”

3.0 Affected Environment and Environmental Consequences

3.1 Introduction

Direct and indirect impacts of the proposed actions will be discussed for BLM-administered and split estate lands. Cumulative impacts for other activities will be discussed for all ownerships in the cumulative impacts analysis area. Analyses will be based on the RFDS created for this document (Table 2, Section 3.1.2, and Appendix 1)

Impact Descriptors

Effects can be temporary (short-term) or long lasting/permanent (long-term). These terms may vary somewhat depending on the resource; therefore, each will be quantified by resource where applicable. Generally speaking:

- **Short-term:** 0-3 years (effects are changes to the environment during and following ground-disturbing activities that revert to pre-disturbance conditions, or nearly so, immediately to within a few years following the disturbance).
- **Long-term:** >3 years (effects are those that would remain beyond short-term ground disturbing activities).

The magnitude of potential effects is described as being major, moderate, minor, negligible, or no effect and is interpreted as follows:

- **Major** effects have the potential to cause substantial change or stress to an environmental resource or resource use. Effects generally would be long-term and/or extend over a wide area.
- **Moderate** effects are apparent and/or would be detectable by casual observers, ranging from insubstantial to substantial. Potential changes to or effects on the resource or resource use would generally be localized and short-term.
- **Minor** effects could be slight but detectable and/or would result in small but measurable changes to an environmental resource or resource use.
- **Negligible** effects have the potential to cause an indiscernible and insignificant change or stress to an environmental resource or use.
- **No effect** = no discernible effect.

3.1.1 General Discussion of Impacts

The act of leasing parcels, itself, does not affect resources. If the proposed parcels are leased, it remains unknown whether development would actually occur, and if so, where specific wells would be drilled and where facilities would be placed. This would not be determined until the BLM receives an application for permit to drill (APD) in which detailed information about proposed wells and facilities would be provided for particular leases. Therefore, this EA discusses potential effects that could occur in the event of development. The amount of development is based on potential well densities and associated activities described in a Reasonably Foreseeable Development Scenario (RFDS) developed for the proposed lease area (Section 3.1.2). As per NEPA regulations at 40 CFR 1502.14(f), 40 CFR 1502.16(h), and 40 CFR 1508.20, mitigation measures to reduce, avoid, or minimize potential impacts are identified by resource below.

Upon receipt of an APD, the BLM would initiate a site-specific NEPA analysis to more fully analyze and disclose site-specific effects of specifically identified activities. In all potential exploration and development scenarios, the BLM would require the use of best management practices (BMP) documented in “Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development” (USDI and USDA 2007), also known as the “Gold Book.” The BLM could also identify APD Conditions of Approval (COA), based on site-specific analysis that could include moving the well location, restrict timing of the project, or require other reasonable measures to minimize adverse impacts (43 CFR 3101.1-2 Surface use rights; Lease Form 3100-11, Section 6) to protect sensitive resources, and to ensure compliance with laws, regulations, and land use plans.

3.1.2 Reasonably Foreseeable Development Scenario Summary and Assumptions

If the proposed area is leased, the RFDS describes four phases of exploration and development that could occur: exploration, drilling, field development and production, and abandonment (Appendix 1). The RFDS and EA use the following assumptions.

1. One well would be drilled per government section of approximately 640 acres (based on State well spacing order).
2. Federal lease wells would require an APD and subsequent site-specific NEPA analysis. Additional site-specific requirements, termed Conditions of Approval (COA), may be attached to the approved APD.
3. The total surface disturbance, including well pad, pipeline, and road construction, is assumed to be approximately 5 acres per well. After the well is drilled, the pad size and road widths would be minimized and unneeded acreage would be reclaimed.
4. The lessee would seek approval for a drilling permit from IDL for fee land wells.
5. Wells would be drilled using conventional drilling techniques (i.e., vertical holes that would not require hydraulic fracturing - based on recent drilling in the adjacent Willow and Hamilton fields and on the geologic characteristics of the reservoir).
6. Producing wells would be incorporated into the Willow Field unit development. Dry wells would be plugged and abandoned in accordance with State and federal requirements, and the site would be reclaimed.
7. Oil and gas leases would be issued for an initial term of 10 years, subject to extension if there is drilling occurring or if there is a producing well on the lease.
8. Where gas is present at more than one layer, dual completion would be identified, targeted, and permitted resulting in 1 well/640 acres.

The level of drilling and associated activities would depend on available lease parcels and the effect of stipulations. Between 2 and 25 wells could be drilled in the proposed lease area resulting in 7 to 87.5 acres of surface disturbance (Table 2). The Lessee on adjacent State and private leases is currently bonded for 11-30 wells and they have drilled eight. A total of 17 wells have been permitted and drilled, three within the proposed lease area (Map 1). Within the boundaries of the Hamilton and Willow (exclusive of the proposed lease area) fields, up to 53 new wells could be developed at 1 well/640 acres (Table 2).

Table 2. Acres of surface disturbance for new wells and associated infrastructure, Little Willow Creek lease area (Alternatives A-C) and potential wells in the Hamilton and Willow fields, Payette County, Idaho.

Activity	Alternative			Field ¹	
	A	B	C	Hamilton	Willow
New Wells (#)	2	22	25	47	6
Well Pad Disturbance (2.5 acres/pad)	5	55	62.5	117.5	15
New Roads (0.25 miles/well)	0.5	5.5	6.25	11.75	1.5
Road Disturbance (4 acres/mile)	2	22	25	47	6
Total Surface Disturbance (acres)	7	77	87.5	164.5	21

¹ Based on 1 well/640 acres for sections that do not currently have a well.

3.2 Soils

3.2.1 Affected Environment – Soils

Detailed soil surveys for Idaho have been published by the Natural Resources Conservation Service (NRCS). The proposed lease area is characterized by sloping lava plateaus with gently to moderately sloping alluvial fans (cone-shaped deposits of sediment crossed and built up by streams), terraces, and bottom lands. Soils in the lease area are mainly coarse sandy loams,

sandy loams, and silt loams (USDA NRCS 2014). Soil erosion susceptibility indices (K-factors) are categorized into the following ranges: low ($K \leq 0.15$), moderate ($K = 0.16 - 0.40$), and high ($K \geq 0.41$). Erosion potential of these soils ranges from moderate (coarse sandy loams) to high (silt loams). K-factors range from 0.20 to 0.64.

The majority of soils are moderately susceptible to erosion (Table 3, Map 3). Approximately 79% of soils (784 acres) are moderately susceptible and 21% (213 acres) are highly susceptible to erosion in the BLM/BLM category; 65% of soils (3,495 acres) are moderately susceptible and 35% (1,899 acres) are highly susceptible in the Private/BLM category. In the Private/Private category 49% of soils are moderately susceptible to erosion and 51% are highly susceptible to erosion (Table 3).

Table 3. Acres of Ownership Categories (Surface/Subsurface Management) in Each K-factor Range.

K-factor Range	Management or Ownership Surface/Subsurface) ¹			Total
	BLM/BLM	Private/BLM	Private/Private	
Moderate ($K = 0.16 - 0.40$)	784 (79%)	3,495 (65%)	4,495 (49%)	8,774 (56%)
High ($K \geq 0.41$)	213 (21%)	1,899 (35%)	4,758 (51%)	6,870 (44%)
<i>Total Acres</i>	997	5,394	9,253	15,644
K-factor ≤ 0.32	682 (68%)	3,031 (56%)	3,891 (42%)	7,604 (49%)
K-factor > 0.32	314 (32%)	2,364 (44%)	9,253 (58%)	8,040 (51%)
<i>Total Acres</i>	997	5,394	9,253	15,644

¹BLM/BLM = BLM manages land surface and subsurface minerals; Private/BLM = BLM manages subsurface minerals (federal mineral estate); Private/Private = land surface and subsurface minerals privately owned.

Alternative C stipulations (Section 2.3) specific to Fragile Soils provide a lease notice (LN-1) indicating mitigation would be required in certain situations. In particular, soils with K-factors greater than 0.32 on slopes greater than 30% would require mitigation to limit erosion. Approximately 51% of the proposed lease area contains soils with K-factors above this threshold (Table 3, Figure 1).

3.2.2 Environmental Consequences – Soils

Impacts to soils are based on the RFDS created for this document (Table 2, Appendix 1).

3.2.2.1 General Discussion of Impacts

Soils are investigated to determine erosion hazard and reclamation suitability by evaluating slope and soil properties such as texture, organic matter content, structure, permeability, depth, available water capacity, and salt concentration. Site specific mitigation would limit but not eliminate impacts to soils in the proposed lease area. The extent of impacts to soils would depend on the amount and type of disturbance associated with particular activity, as well as the erosion risk of a given area. As slopes become steeper, the risk of soil instability increases. Actions that alter soil characteristics such as plant cover and composition (amount and species), soil structure, permeability, and compaction may increase erosion potential.



Figure 1. Typical topography, slope, and soil conditions of BLM land in the proposed lease area.

Direct impacts from exploration and development include mixing and breaking down soil components, compaction, and removal of soils in the short term (0-3 years) and long term (>3 years). Compaction alters soil structure (e.g., reduced porosity, increased bulk density) and, therefore, its functionality (e.g., its ability to support healthy vegetation communities and to properly cycle water and nutrients) over the long term (USDA and USFS 2006). Indirect impacts to soils would include removal of ground cover (e.g., vegetation, microbiotic crusts, and litter) in the short term, thus exposing soil surface to wind and water erosion and colonization by weedy, invasive, disturbance related vegetation (e.g., cheatgrass) and or noxious weeds (e.g., rush skeletonweed) over the long term. Reclamation would be required once wells and infrastructure are no longer in use; therefore, soil structure and function would improve from disturbance related levels over the long term.

Oil and gas exploration and development could increase the potential for fire ignitions due to sparks from heavy equipment and/or vehicles, particularly when soils and vegetation are dry. If a fire burns hot enough, it may impact soil directly by altering its physical properties. Physical properties of soils that are dependent on organic matter (e.g., soil structure, pore space, aggregation) could be affected by heating during a fire (USFS RMRS 2014). Fire could also impact soil hydrology (i.e., infiltration) by increasing water repellency (USFS RMRS 2014). However, fires generally move quickly through shrub and grass communities like those in the proposed lease area. Therefore, it is more likely that soils would be indirectly impacted by the loss of vegetative cover leaving them exposed to erosion, as well as alterations in vegetation which, in turn, could alter soil chemistry and overall productivity over the long term.

3.2.2.2 Alternative A

No BLM managed surface or subsurface/federal mineral estate parcels would be leased, so soils would not be directly impacted in these parcels. Oil and gas activities (wells, well pads, and road construction) on private surface/subsurface could disturb up to 7 acres of soils and remove up to 7 acres of vegetation per the RFDS. Moderate to major, direct and indirect, adverse impacts to soils (compaction, soil loss, loss of structure and function, and colonization by weedy plants) would occur over the short and long term on the 7 acres (<0.1% of the proposed lease area). Soils in the high range for erosion susceptibility would incur greater impacts than soils in the moderate range if disturbed (Table 3). Risk of fire starts would be low because there would be little oil and gas development (two wells plus infrastructure); therefore, fire related soil impacts would be minor. Overall impacts to soils would be negligible due to the very small disturbance footprint possible under this scenario.

3.2.2.3 Alternative B

The BLM would issue leases on 997 BLM surface acres and 5,352 acres of federal mineral estate; however, the NSO and NSSO stipulations would preclude any direct disturbance to soils in these parcels until the FRMP is completed. Impacts to soils, including potential fire related impacts, would be identical to Alternative A (i.e., up to 7 acres of moderate to major disturbance) until implementation of the FRMP.

The RFDS for this alternative indicates up to 22 wells and associated infrastructure would cause direct soil impacts on up to 77 acres (0.5% of the proposed lease area) including BLM surface and federal mineral estate, and private surface/subsurface lands. These soils could sustain moderate to major, adverse, direct impacts, such as compaction and removal, and indirect impacts, such as reduction in productivity, over the short and long term associated with well and well pad development and road building. Minor (e.g., limited vegetation disturbance and wildfires) to major (e.g., roads and activities increase disturbances and wildfires) indirect impacts could occur where vegetation shifts to exotic annual dominated communities (e.g., associated with roads or wildfires) occur and soil protection is reduced or eliminated. These areas would be more susceptible wind and water erosion over the long term. However, the extent (magnitude and scale) of impacts would depend on land use designations and stipulations set forth in the FRMP.

3.2.2.4 Alternative C

Impacts would be similar to those described in Alternative B (Section 3.2.2.3); however, per the RFDS, direct impacts on up to 88 acres (0.6% of the proposed lease area) could occur on BLM surface, federal mineral estate, and private lands. Indirect impacts would be more likely to affect federal mineral estate lands in this scenario because of the increased amount of disturbance and closer proximity of disturbances. Direct and indirect impacts associated with well and road construction could be reduced where fragile soils are avoided (LN-1, Section 2.3).

3.2.3 Mitigation

Prior to authorization, proposed actions (APDs) would be evaluated on a case-by-case basis and would be subject to mitigation measures in order to maintain the soil system. Where residual

impacts are expected based on future site specific APD analyses, measures would be taken to reduce, avoid, or minimize potential impacts to soil resources from exploration and development activities. Examples of mitigation include avoiding excessively steep slopes and areas poorly suited to reclamation, limiting the total area of disturbance, rapid reclamation, erosion/sediment control, soil salvage, re-vegetation, weed control, slope stabilization, surface roughening, and protective fencing.

3.2.4 Cumulative Impacts – Soils

Cumulative impacts to soils are based on the RFDS created for this document (Appendix 1), the Willow Field RFDS, and the actions identified below.

3.2.4.1 Scope of Analysis

The cumulative impact analysis area (CIAA) includes the proposed lease area and the Willow Field southwest of the lease area plus a 0.5-mile buffer totaling approximately 32,460 acres (50 square miles) (Map 3). The CIAA contains private, State, and BLM surface and federal mineral estate lands. This area was selected because the lands it encompasses have similar topographic, geologic, and soil attributes; soil condition (due to land use and wildfire) and susceptibility to erosion (K-factors) are also similar.

3.2.4.2 Current Conditions, Effects of Past and Present Actions, and Reasonably Foreseeable Future Actions

Soil conditions in the CIAA are nearly identical to those in the proposed leased area; the proposed lease area makes up the majority of the CIAA and the Willow Field has undergone similar disturbances. The levels and intensities of anthropogenic activities across all land jurisdictions in the CIAA has perpetuated increases of early successional, highly disturbed landscapes (Leu and Hanser 2011) that are at higher risk for cumulative soil impacts. Past, ongoing, and future land uses contributing to soil conditions include livestock grazing, agricultural development, rights-of-way, and oil and gas development. Wildfire, though not a land use, has also influenced soil conditions.

Livestock Grazing - Both BLM and private lands within CIAA, the proposed lease area in particular, encompass portions of the Sand Hollow, Rock Quarry Gulch, Dahnke, Hashegan, and Kaufman grazing allotments. Livestock grazing can damage soils via compaction, disruption of the soil profile, and remove vegetative cover exposing soils to erosion, particularly where livestock tend to congregate. Historic and recent grazing management in these allotments have contributed to overall soil condition. Livestock grazing would continue at current levels into the foreseeable future.

Agricultural Development - Conversion from shrub and grass communities to cultivated croplands on private land has altered soils on approximately 28% (8,962 acres) of the CIAA. Future agricultural development is unlikely (or would be negligible) because water necessary for crop production is limited.

Rights-of-way (power lines, roads) - Three short power line segments totaling approximately one mile are present in the CIAA. Power lines typically have two-track roads associated with them

which disturb and impact soils. Approximately 9 miles of developed roads including the Little Willow Road (7.8 miles) and Big Willow Road (1.2 miles) run through the CIAA. These features combined have a disturbance footprint of approximately 40 acres; which, to a small degree, have contributed to present soil conditions across the CIAA. Future roads would be constructed in association with development of wells, well pads, and other infrastructure or facilities necessary to maintain oil and gas production. Road construction and maintenance would continue to affect soil erosion and displacement within maintained buffers. These effects are spatially restricted and occur over a continuous temporal scale.

Oil and Gas Development - Currently there are 11 wells and 1 well surface site in the CIAA. An estimated 30-41 acres (depending on infrastructure) of soils have been disturbed in the CIAA to date due to oil and gas exploration and development. An additional 6 wells could be drilled in the Willow Field portion of the CIAA in the future disturbing 21 acres of soils.

Wildfire - Approximately 16,655 acres (51 %) of the CIAA has burned at least one time. Multiple fires have burned within the CIAA, mainly in the 1980s, with some overlap. These fires have perpetuated increases of disturbance related plants, which are indicative of decreased soil productivity.

3.2.4.3 Alternative A – Cumulative Impacts

Disturbance from two wells and related infrastructure (7-acre footprint) would produce negligible short and long term impacts to soils when combined with ongoing and future land uses and disturbance. An additional 6 wells in the Willow Field portion of the CIAA would disturb soils on approximately 21 acres (<0.1% of the CIAA). Livestock grazing, rights-of-way construction and maintenance, and Willow Field oil and gas development combined would produce overall minor to moderate soil impacts over the short and long term. No or negligible additional impacts would occur from development of agriculture due limited water availability necessary for these actions. Wildfires could produce minor to major direct and indirect impacts to soils depending on their size and frequency.

3.2.4.4 Alternatives B and C– Cumulative Impacts

Development of 22 to 25 wells (77-87.5-acre footprint) and related infrastructure would produce minor short and long term impacts to soils in the CIAA when combined with ongoing and future land uses and disturbance. Cumulative impacts to soils from ongoing and future actions including livestock grazing, agricultural development, roads and ROWs, oil and gas development, and wildfire would be identical to those described for Alternative A.

3.3 Vegetation

3.3.1 Affected Environment – Vegetation

General Vegetation

Two ecological sites comprise the majority of the proposed lease area. South Slope Granitic 8-12 is associated with coarse sandy loams and is the primary ecological site occurring on steeper slopes and upper portions of gentle slopes. Loamy 8-12 is associated with sandy loams and silt loams which are present in the bottoms, on toe slopes, and lower portions of steeper slopes.

Basin big sagebrush and bluebunch wheatgrass vegetation communities are characteristic of South Slope Granitic 8-12 sites, and Wyoming big sagebrush and bluebunch wheatgrass with Thurber's needlegrass are characteristic of Loamy 8-12 sites. However, based on 2014 site visits, current plant communities on BLM-administered lands are largely dominated by cheatgrass, an invasive annual grass, and introduced annual forbs (e.g., tall tumbled mustard, tansymustard, and clasping pepperweed); which is a result of frequent wildfires in the 1980s and recurring spring livestock grazing (Map 4). Between 1980 and 1986, approximately 49% of the area burned once, 15% burned twice, and 3% burned three times. Perennial plant species occasionally present include Sandberg bluegrass, crested wheatgrass, rabbitbrush, and small pockets of remnant bitterbrush, stiff sagebrush, and Wyoming big sagebrush. In general, north-facing slopes are wetter and contain slightly more perennial vegetation than south-facing, drier slopes; therefore, northerly slopes tend to be more resistant to disturbance and support more resilient plant communities.

General vegetation cover types mapped for the proposed lease area are consistent with observations made during site visits (Table 4). Exotic Annuals (i.e., cheatgrass and introduced annual mustards) is the dominant cover type for all ownership configurations (Figure 2). Big Sagebrush (mainly Wyoming big sagebrush and/or basin big sagebrush with cheatgrass and Sandberg bluegrass) is the second most common cover type followed by Bunchgrass (mainly Sandberg bluegrass with cheatgrass and occasionally shrubs) and Stiff Sagebrush (mainly stiff sagebrush with cheatgrass, Sandberg bluegrass, and introduced forbs) on BLM/BLM and Private/BLM. On Private/Private, agriculture is the second most common cover type followed by Big Sagebrush. All remaining cover types comprise 4% each or less for all ownership configurations.

Table 4. Acres of general vegetation cover types¹ and percent composition by mineral ownership, Little Willow Creek proposed lease area, Payette County, Idaho.

General Cover Type	Ownership (Surface/Subsurface) ²			Total Acres
	BLM/BLM	Private/BLM	Private/Private	
Agriculture	3.3 (<1%)	145.6 (3%)	3,004.6 (33%)	3,153.5 (20%)
Big Sagebrush ³	258.4 (26%)	1,216.3 (23%)	1,478.6 (16%)	2,953.3 (19%)
Bitterbrush	6.6 (<1%)	15.6 (<1%)	15.8 (<1%)	38.0 (<1%)
Bunchgrass	112.5 (11%)	434.2 (8%)	336.2 (4%)	883.0 (6%)
Exotic Annuals	460.4 (46%)	3,125.0 (59%)	3,756.8 (41%)	7,342.2 (47%)
Greasewood	29.8 (3%)	63.1 (1%)	95.6 (1%)	188.5 (1%)
Salt Desert Shrub	28.2 (3%)	155.3 (3%)	112.9 (1%)	296.4 (2%)
Stiff Sagebrush	91.4 (9%)	162.0 (3%)	346.5 (4%)	599.9 (4%)
Wet Meadow	1.1 (<1%)	3.5 (<1%)	29.0 (<1%)	34.0 (<1%)
Other ⁴	3.1 (<1%)	13.9 (<1%)	30.1 (<1%)	47.1 (<1%)
Total Acres ⁵	995	5,335	9,206	15,536

¹ Pacific Northwest National Laboratory vegetation mapping data (2002).

² BLM/BLM = BLM manages land surface and subsurface minerals; Private/BLM = BLM manages subsurface minerals (federal mineral estate); Private/Private = land surface and subsurface minerals privately owned.

³ Big Sagebrush Mix and Big Sagebrush were combined because the two have nearly identical components.

⁴ Other includes Mountain Big Sagebrush, Mountain Shrubs, Rabbitbrush, Sparse Vegetation, Urban, and Water; which were combined because they represent a small portion (<15 acres in each ownership category) of the proposed lease area.

⁵ Total acres are slightly less than 15,644 due to GIS processing of PNNL data set (raster data vs. vector data).



Figure 2. Typical vegetation on BLM surface and mineral estate land in the proposed lease area. Note tall tumble mustard, cheatgrass, and Sandberg bluegrass in the foreground and a patch of green rabbitbrush in the background.

Riparian Vegetation

There are 39 acres (<1% of the total lease acres) in the Wet Meadow cover type, which is indicative of riparian vegetation (e.g., cottonwoods, willows, rushes, and sedges) (Table 4). The vast majority of the Wet Meadow cover type (35 acres) is on private lands with private subsurface; only 1.1 acres are on BLM surface managed lands (BLM/BLM) and 3.5 acres are on federal mineral estate (Private/BLM). These areas are mainly associated with Little Willow Creek and the McIntyre Canal and are primarily on private land with private subsurface (Map 5). Additionally, National Wetland Inventory mapping shows approximately 56 acres (which overlap the Wet Meadow cover type to a small degree) of water features (e.g., emergent wetlands, ponds, seeps, and reservoirs) (Map 6). These features are typically used as livestock water sources and are generally sparsely vegetated as a result.

Special Status Plants (SSP)

Two sensitive plant species are mapped in the proposed lease area, an element occurrence (EO) of Snake River goldenweed (BLM Type 3 SSP) and an historical EO of calcareous buckwheat (BLM Type 3 SSP). Three additional EOs of Snake River goldenweed and one EO of Aase's onion (BLM Type 2 SSP) are present within 1 mile of the proposed lease area (Map 5). The calcareous buckwheat was last observed in 1933 and may no longer exist; further, the mapping precision for this EO is very low (G precision)^C, so it is possible that the EO is actually outside the proposed lease area.

Three of the Snake River goldenweed EOs (which includes the EO in the proposed lease area) were not given condition ranks. However, EO records from 2000 indicated that these EOs occurred in dry grasslands-annual grasslands with some perennial species-within weedy rangeland with occasional fire disturbance. Based on the degradation of the vegetation communities across the proposed lease area, and that these EOs are largely mapped in the annual grass cover type, population viability is likely poor. The fourth EO was given a condition rank of D signifying poor estimated viability; the 2006 EO report indicated that the area had burned multiple times and was dominated by annual weeds with few remaining shrubs, and population numbers were drastically lower than previous years. The Aase's onion EO was ranked B for condition in 1995 indicating good estimated viability; however, the EO report states the area had burned, shrubs had not re-established, and cheatgrass was common.

Noxious Weeds

'Noxious' is a legal designation given by the Director of the Idaho State Department of Agriculture to any plant having the potential to cause injury to public health, crops, livestock, land or other property (Idaho Statute 22-2402). The Boise District BLM has an active weed control program that annually updates the locations of noxious weeds and treats known weed infestations utilizing chemical, mechanical, and biological control techniques. Infestations of noxious weeds are treated contingent upon the BLM annual weed budget, employee availability, and noxious weed priority.

There are no noxious weeds mapped in the proposed lease area according to BLM Boise District noxious weeds database. However, numerous infestations of rush skeletonweed and Scotch thistle have been recorded in the vicinity (within three to five miles). Many of these infestations have been chemically treated at least once since 2001. Although no noxious species have been recorded within the proposed lease area boundary, it is likely that they do occur to some degree based on the degraded state of vegetation communities.

3.3.2 Environmental Consequences – Vegetation

Impacts to vegetation are based on the RFDS created for this document (Table 2, Appendix 1).

^C G is the lowest precision and is typically applied by the Idaho Fish and Game's Idaho Natural Heritage program to historic observations and or observations lacking GPS data. A large buffer is created around a centroid, indicating that the location of the EO likely occurs/occurred somewhere within the polygon, but confidence is low as to its precise location. This EO is not depicted on the map provided because the location polygon is so large (77miles²).

3.3.2.1 General Discussion of Impacts

Site specific mitigation and stipulations would limit impacts to sensitive vegetation (SSPs) and sensitive areas (riparian areas). The level of impacts to vegetation would depend on the amount and type of disturbance associated with a given activity.

General Vegetation

Lease development would directly impact vegetation by removing, damaging (i.e., breakage, trampling), or burying plants. When vegetation is removed and soil is exposed, noxious and invasive species may spread degrading overall condition of plant communities. The influx of machinery and vehicle travel associated with development, production, and improved access would increase the risk of fire starts, especially once vegetation has cured (late summer). Fire would damage or remove vegetation and potentially further degrade vegetation community structure and function. Burned areas would be more susceptible to noxious and invasive species colonization/spread and overall habitat degradation. Roads and degraded habitats would increase fragmentation by reducing the size of and increasing the distance between native vegetation stands.

Surface disturbing activities could also indirectly affect vegetation by disrupting seed banks and mixing, eroding, or compacting soils. Soil erosion would reduce the substrate available for plants and soil compaction could limit seed germination. Fugitive dust generated by construction activities and travel along dirt roads could affect nearby plants by depressing photosynthesis, disrupting pollination, and reducing reproductive success. Impacts to plants occurring after germination but prior to seed set could be particularly harmful as both current and future generations would be affected.

Riparian Vegetation

Direct and indirect impacts to riparian vegetation by surface disturbing activities would be the same as those described for general vegetation. However, mitigation and stipulations would likely prevent direct impacts to riparian vegetation, except on private lands with private mineral estate.

Special Status Plants

Direct impacts by surface disturbing activities would be the same as those described for general vegetation; however, mitigation and stipulations could prevent direct impacts. Networks of oil and gas infrastructure, roads in particular, could create pollinator and seed dispersal barriers. Vegetation removal and displacement by invasive and/or noxious species would also cause indirect impacts to sensitive plants via habitat degradation. Habitat fragmentation could also lead to a decrease in pollinators over time. All of these factors could decrease long-term EO viability.

Noxious Weeds

Both rush skeletonweed and Scotch thistle are capable of invading and dominating disturbed areas (roadsides, areas burned by wildfire, etc.) over a wide range of precipitation regimes and habitats (Sheley and Petroff 1999). Road building and use would create corridors and seed

sources for noxious weed establishment and spread. Noxious weed inventories and treatments could offset some impacts.

3.3.2.2 Alternative A

General Vegetation

Development and production on private surface with private subsurface could disturb up to 7 acres (<0.1% of the proposed lease area) of vegetation. Moderate to major, direct (i.e., removal, breakage, and burying of vegetation) and indirect (e.g., influx of noxious and invasive species, disruption of seed bank, and plant community degradation) impacts would occur over the short (0-3 years) and long (>3 years) term in the isolated areas associated with wells and roads. The federal mineral estate (6,349 acres) would not be leased, so vegetation would not be directly affected in these parcels.

Vegetation in the unleased area could receive similar negligible to minor indirect impacts where invasive annuals, noxious weeds, or fires spread from developed areas. The degree of indirect impacts would depend on the condition and components of plant communities prior to disturbance. Those plant communities maintaining shrubs and native perennial grasses could better resist invasive and noxious weed invasions; however, they would be less resistant if affected by fire. New and upgraded roads would cause minor increased fragmentation.

The threat of fire ignitions could increase a minor amount by equipment use and vehicles travelling on existing and new (0.5 miles) access roads. The extent of impacts to vegetation across all jurisdictions would be influenced by fire size and behavior, as well as the pre-fire vegetation community conditions.

Riparian Vegetation

There would be no impacts to riparian vegetation or habitat on BLM-administered land or federal mineral estate. The extent of short- and long- term direct impacts (i.e., removal or damage) and long-term indirect impacts (i.e., habitat degradation) to riparian vegetation on private mineral estate would depend on the proximity of the disturbance. Any impacts would likely come from access roads associated with wells/well pads.

Special Status Plants

The Snake River goldenweed EO, or other currently mapped special status plant EOs, would not be directly impacted (i.e., removed or damaged). Long-term indirect impacts, such as habitat degradation or fragmentation, would be negligible because overall habitat condition is already relatively poor and the 0.5 mile of new access roads would be ≥ 2.5 miles away.

Noxious Weeds

The 0.5 miles of new roads could serve as minor noxious and invasive species corridors over the long term.

3.3.2.3 Alternative B

General Vegetation

The NSO and NSSO stipulations would apply until the FRMP is finalized and implemented; therefore, until that time, direct impacts to vegetation would be similar to those described for Alternative A (Section 3.3.2.2).

The RFDS for this alternative specifies up to 77 acres (0.5% of the proposed lease area) of vegetation on private surface and subsurface would sustain moderate to major, adverse, direct impacts (i.e., removal, breakage, and burying of vegetation). Minor to major indirect impacts (e.g., influx of noxious and invasive species, disruption of seed bank, and plant community degradation) could occur over the long term. Because wells and roads would occur throughout the proposed lease area, both private and federal mineral estate lands could be adversely affected. Moderate increases in habitat fragmentation could occur, especially where invasive species increase adjacent to roads. Minor (access restricted by private landowners and fire starts remain similar to current levels) to major (access not restricted and fire starts increase substantially) wildfire impacts could degrade vegetation conditions increasing fragmentation over the long term. However, the extent (magnitude and scale) of impacts to vegetation would depend on land use designations and stipulations set forth in the FRMP.

Riparian Vegetation

Direct impacts (i.e., removal or damage) to riparian areas would not occur on federal mineral estate lands. Long-term indirect impacts on BLM surface and federal mineral estate riparian vegetation would be similar to Alternative A (Section 3.3.2.2) and depend on the proximity of the disturbance. The extent of indirect impacts could be greater than Alternative A because more development would require more access roads (0.5 versus 5.5 miles of new access roads).

Special Status Plants

No direct impacts to the Snake River goldenweed EO or other currently mapped special status plant EOs would occur. Long-term indirect impacts to SSPs on BLM surface and federal mineral estate could be minor to moderate, but would depend on the proximity of the disturbance. However, the degree of these impacts could be greater than Alternative A because development could occur within 0.2 miles of the EO. Increased fragmentation and wildfire potential would adversely affect the EO over the long term.

Noxious Weeds

The 5.5 miles of new roads (and upgrades of existing roads) accessing 22 wells would serve as minor to moderate noxious and invasive species corridors over the long term.

3.3.2.4 Alternative C

General Vegetation

The same area would be leased as Alternative B, but Cascade RMP stipulations and other lease notices for development would apply specific to riparian areas and SSPs. According to the RFDS, up to 87.5 acres (0.6% of the proposed lease area) would sustain moderate to major, adverse, direct impacts (i.e., removal, breakage, and burying of vegetation). Vegetation community degradation, increased invasive species, seed bank disruption, and wildfire impacts would be similar to those described in Alternative B (Section 3.3.2.3); however, federal mineral

reserve lands (with minor exceptions associated with avoidance buffers) would be more likely to be affected because direct disturbances would occur on rather than adjacent to these lands.

Riparian Vegetation

Negligible indirect impacts could occur over the short and long term. Stipulations CSU-1 and CSU-2 (Section 2.3) would preclude direct impacts and limit indirect impacts.

Special Status Plants

Impacts (habitat degradation and fragmentation) would be similar to those described for Alternative B (Section 3.3.2.3); however, development could occur closer to EOs producing greater indirect impacts.

Noxious Weeds

The 6.25 miles of new access roads associated with 25 wells would increase the threat of noxious and invasive species spread slightly more than Alternative B (Section 3.3.2.3), but would remain in the minor to moderate range, overall. There are no stipulations or mitigation specific to noxious weeds under this scenario, but the Boise District BLM's annual weed control program could help mitigate noxious weed expansion.

3.3.3 Mitigation

Site specific mitigation would be addressed at the APD stage of exploration and development. If necessary, COAs could be applied including re-vegetation strategies using native and/or desirable non-native plant species, soil enhancement practices, modification of livestock grazing, and fencing of reclaimed areas. Noxious weed inventories and treatments may also be required.

Special Status Plants

Section 7 of the Endangered Species Act (ESA) requires BLM land managers to ensure that any action authorized, funded, or carried out by the BLM is not likely to jeopardize the continued existence of any threatened or endangered species and that it avoids any appreciable reduction in the likelihood of recovery of affected species. Consultation with the U. S. Fish and Wildlife Service (FWS) is required on any action proposed by the BLM or another federal agency that affects a listed species or that jeopardizes or modifies critical habitat.

The BLM's Special Status Species Policy outlined in BLM Manual 6840, Special Status Species Management, is to conserve listed species and the ecosystems on which they depend and to ensure that actions authorized or carried out by BLM are consistent with the conservation needs of special status species and do not contribute to the need to list any of these species. The BLM's policy is intended to ensure the survival of those plants that are rare or uncommon, either because they are restricted to specific uncommon habitat or because they may be in jeopardy due to human or other actions. The policy for federal candidate species and BLM sensitive species is to ensure that no action that requires federal approval should contribute to the need to list a species as threatened or endangered.

Prior to any exploration or development, the BLM would conduct site specific rare and sensitive plant surveys. If rare (threatened, endangered, proposed, or candidate species) or sensitive plants

(SSPs) are found, avoidance stipulations (e.g., disturbance buffers) would be applied. If listed species are found, BLM would consult with the USFWS during the analysis phase of processing an ADP.

3.3.4 Cumulative Impacts – Vegetation

Cumulative impacts to vegetation are based on the RFDS created for this document (Appendix 1), the Willow Field RFDS, and the actions described below.

3.3.4.1 Scope of Analysis

The CIAA for vegetation, consistent with the soils CIAA, encompasses the proposed lease area and the Willow field totaling plus a 0.5-mile buffer totaling approximately 32,460 acres (50 miles²) (Map 4). This area was selected because it contains similar ecological sites and plant community components, conditions are similar, and oils and gas leasing and development is occurring (land uses are comparable).

3.3.4.2 Current Conditions, Effects of Past and Present Actions, and Reasonably Foreseeable Future Actions

Conditions across the CIAA are similar to conditions in the proposed lease sale perimeter: vegetation communities have been degraded and are largely dominated by non-native, weedy, annual species with small patches of remnant native shrubs and perennial grasses. There are no additional special status plants or noxious weeds mapped within the CIAA. Past, ongoing, and future land uses contributing to condition of vegetation include livestock grazing, agricultural development, rights-of-way, and oil and gas development. Wildfire has also been instrumental in shaping the vegetation community components and overall condition.

Livestock Grazing - Both BLM and private lands within CIAA, the proposed lease area in particular, encompass portions of the Sand Hollow, Rock Quarry Gulch, Dahnke, Hashegan, and Kaufman grazing allotments. Livestock grazing can damage and remove vegetation, especially where livestock tend to congregate. Historic and recent grazing management in these allotments have contributed to overall plant community condition. Livestock grazing would continue at current levels into the foreseeable future.

Agricultural Development - Conversion from shrub and grass communities to cultivated croplands on private land has occurred on approximately 28% (8,962 acres) of the CIAA. Future agricultural development is unlikely (or would be negligible) because water necessary for crop production is limited.

Roads and Rights-of-way (ROW) - Road or ROW (powerlines and pipelines) construction and subsequent ongoing maintenance (e.g., blading, grading, and/or spraying) along these features will continue to affect vegetation within and adjacent to maintained buffers. Blading and grading disturb soils and vegetation and often create conditions conducive to noxious and invasive species establishment. Spraying of these sites helps to keep weeds and weedy species relatively restricted to the maintained buffers or to a minimum (e.g., around powerline poles, which are kept relatively free of vegetation to prevent fire). As a result, upland vegetation is often sparse in these locations. Road construction and maintenance would continue to impact

vegetation within maintained buffers. These effects are generally spatially restricted and occur over a continuous temporal scale.

Three short power line segments totaling approximately one mile are present in the CIAA. Power lines typically have two-track roads associated with them which disturb and impact vegetation. Approximately 9 miles of developed roads including the Little Willow Road (7.8 miles) and Big Willow Road (1.2 miles) run through the CIAA. Combined, these features have a disturbance footprint of approximately 40 acres; which has contributed to present plant community conditions. Additional roads are anticipated to access wells, well pads, and other infrastructure or facilities necessary to maintain oil and gas production.

Oil and Gas Development - Currently there are 11 wells and 1 well surface site in the CIAA. Vegetation on approximately 30-41 acres (depending on infrastructure) has been removed or disturbed to date due to oil and gas exploration and development. An additional 6 wells could be drilled in the Willow Field portion of the CIAA which would disturb approximately 21 acres of vegetation.

Wildfire - Several fires have burned across the CIAA, mainly in the 1980s. Approximately 51 % (16,655 acres) of the CIAA has burned at least one time. These fires have perpetuated increases of disturbance related plants, degrading overall vegetation community conditions. Disturbance related vegetation often equates to fine fuels which burn readily creating a negative feedback loop.

3.3.4.3 Alternative A – Cumulative Impacts

Disturbance from two wells and related infrastructure would produce negligible additive short- and long-term impacts to vegetation. In the Willow Field portion of the CIAA, an additional 6 wells would disturb vegetation on approximately 21 acres (<0.1% of the CIAA) combined with the 30-41 acres of existing disturbance would produce minor impacts over the short and long term. Ongoing livestock use in areas grazed each spring (before seed set) could perpetuate disturbance related plants. Sensitive plants could also be impacted directly via trampling by livestock. Rights-of-way construction and maintenance would produce overall minor impacts to vegetation including habitat degradation and fragmentation over the short and long term. Wildfires could produce minor to major direct and indirect impacts to vegetation depending on fire size and frequency. Further agricultural development is improbable, so no additional impacts to vegetation would take place.

3.3.4.4 Alternatives B and C – Cumulative Impacts

Development of 22 to 25 wells and related infrastructure totaling 77 to 87.5 acres of disturbance would produce minor short and long term additive impacts to vegetation in the CIAA. Cumulative impacts to vegetation from ongoing and future actions identified in section 3.3.3.2 (livestock grazing, agricultural development, roads and ROWs, oil and gas development, and wildfires) would be identical to those described for Alternative A.

3.4 Air Resources

Air resources include air quality, air quality related values (AQRVs), and climate change. As part of the planning and decision making process, the BLM considers and analyzes the potential effects of BLM and BLM-authorized activities on pollutant emissions and on air resources.

The Environmental Protection Agency (EPA) has the primary responsibility for regulating air quality, including seven criteria air pollutants subject to National Ambient Air Quality Standards (NAAQS). Pollutants regulated under NAAQS include carbon monoxide (CO), lead, nitrogen dioxide (NO₂), ozone, particulate matter with a diameter less than or equal to 10 microns (PM₁₀), particulate matter with a diameter less than or equal to 2.5 microns (PM_{2.5}), and sulfur dioxide (SO₂). Two additional pollutants, nitrogen oxides (NO_x) and volatile organic compounds (VOCs) are regulated because they form ozone in the atmosphere. Air quality regulation is also delegated to the IDEQ. Air quality is determined by pollutant emissions and emission characteristics, atmospheric chemistry, dispersion meteorology, and terrain. The AQRVs include effects on soil and water such as sulfur and nitrogen deposition and lake acidification, and aesthetic effects such as visibility.

Climate is the composite of generally prevailing weather conditions of a particular region throughout the year, averaged over a series of years. Climate change includes both historic and predicted climate shifts that are beyond normal weather variations.

3.4.1 Affected Environment – Air Resources

Air Quality

Based on data from monitors located in Baker County Oregon (west and generally upwind of the lease area) and Ada and Canyon counties (southeast and generally downwind of the lease area), air quality in Payette County is believed to be much better than required by the NAAQS. The EPA air quality index (AQI) is an index used for reporting daily air quality (<http://www.epa.gov/airdata/>) to the public. The index tells how clean or polluted an area's air is and whether associated health effects might be a concern. The EPA calculates the AQI for five criteria air pollutants regulated by the Clean Air Act (CAA): ground-level ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide. For each of these pollutants, EPA has established NAAQS to protect public health. An AQI value of 100 generally corresponds to the primary NAAQS for the pollutant. The following terms help interpret the AQI information:

- **Good** – The AQI value is between 0 and 50. Air quality is considered satisfactory and air pollution poses little or no risk.
- **Moderate** – The AQI is between 51 and 100. Air quality is acceptable; however, for some pollutants there may be a moderate health concern for a very small number of people. For example, people who are unusually sensitive to ozone may experience respiratory symptoms.
- **Unhealthy for Sensitive Groups** – When AQI values are between 101 and 150, members of “sensitive groups” may experience health effects. These groups are likely to be affected at lower levels than the general public. For example, people with lung disease are at greater risk from exposure to ozone, while people with either lung disease or heart disease

are at greater risk from exposure to particle pollution. The general public is not likely to be affected when the AQI is in this range.

- **Unhealthy** – The AQI is between 151 and 200. Everyone may begin to experience some adverse health effects, and members of the sensitive groups may experience more serious effects.
- **Very Unhealthy** – The AQI is between 201 and 300. This index level would trigger a health alert signifying that everyone may experience more serious health effects.

AQI data show that there is little risk to the general public from air quality in the analysis area (Table 5). Based on available aggregate data for Baker, Ada, and Canyon counties (the nearest counties with monitoring data) for years 2011–2013, more than 84% of the days were rated “good” and the three-year median daily AQI was 19 to 32. Moderate or lower air quality days were typically associated with winter inversions or summer wildfire activity.

Table 5. Air Quality Index Report – Analysis Area Summary (2011-2013), Baker County Oregon and Ada Canyon Counties Idaho.

County ¹	# Days in Period	Median AQI	# Days rated Good	Percent of Days Rated Good	# Days Rated Moderate	# Days Rated Unhealthy for Sensitive Groups	# Days Rated Unhealthy	# Days Rated Very Unhealthy
Baker	1,084	28	915	84	167	2	0	0
Ada	1,088	32	917	84	157	11	2	1
Canyon	1,019	19	925	91	87	4	3	0

Source: EPA 2013a.

Emissions in Payette County are low, due to a small populations and little industrial activity. Based on 2011 emission inventory data available from the EPA National Emission Inventory, oxides of nitrogen, carbon monoxide, ≤ 10 micron particulate matter (PM₁₀), volatile organic compounds, and carbon dioxide were the most common non-biogenic emissions in Payette County (EPA 2014a). As described above, these emissions occur in an area with good air quality.

Table 6. Annual emissions (tons/year) of typical pollutants, typical annual emissions for a well (Upper Green River, Wyoming), and emissions for the reasonably foreseeable development scenario wells (Payette County) and cumulative impacts analysis area (Baker, Ada, Canyon, and Payette counties), Idaho and Oregon.

Pollutant	Payette County	Cumulative Impacts Analysis Area	Per Well ¹	Alternative (%increase over Payette County values)			Hamilton and Willow Fields ⁽²⁾
				A	B	C	
NOx (Oxides of Nitrogen)	1,445.4	24,851.4	14.6	29.2 (2%)	321.2 (22.2%)	365 (25.3%)	774 (3.1%)
CO (Carbon Monoxide)	6,308.3	149,894.3	3.9	7.8 (0.1%)	85.8 (1.4%)	97.5 (1.6%)	207 (0.1%)
SO ₂ (Sulfur Dioxide)	39.1	2,800.2	0.0004	0.0008 (<0.01%)	0.0088 (0.02%)	0.01 (0.03%)	0.02 (0.001%)
PM ₁₀ (Particulates)	6,195.6	61,101.9	6.7	13.4	147.4	167.5	355.1

Pollutant	Payette County	Cumulative Impacts Analysis Area	Per Well ¹	Alternative (%increase over Payette County values)			Hamilton and Willow Fields ⁽²⁾
				A	B	C	
with diameters ≤ 10 microns or $\leq 10 \times 10^{-6}$ meters)				(0.2%)	(2.4%)	(2.7%)	(0.7%)
PM _{2.5} (Particulates with diameters ≤ 2.5 microns or $\leq 2.5 \times 10^{-6}$ meters)	828.4	12,815.4	0.8	1.6 (0.2%)	17.6 (2.1%)	20.0 (2.4%)	42.4 (0.3%)
VOCs (Volatile Organic Compounds)	1,123.1	28,539.1	5.2	10.4 (0.9%)	114.4 (10.2%)	130.0 (11.6%)	275.6 (1.0%)
HAPs (Hazardous Air Pollutants)							
Benzene	18.2	583.2	0.12	0.2 (1.3%)	2.6 (14.5%)	3.0 (16.5%)	6.4 (1.2%)
Toulene	67.4	1,509.5	0.22	0.4 (0.7%)	4.8 (7.2%)	5.5 (8.2%)	11.7 (0.8%)
Ethylbenzene	9.7	190.3	0.00003	0.00006 (<0.01%)	0.0007 (0.01%)	0.0008 (0.01%)	0.002 (0.001%)
Xylene	39	801.5	0.17	0.3 (0.9%)	3.7 (9.5%)	4.3 (10.9%)	9.0 (1.1%)
n-Hexane	23	615.1	0.20	0.4 (1.7%)	4.4 (19.1%)	5.0 (21.7%)	10.6 (1.7%)
Total HAPs	157.3	3,654.6	0.72	1.4 (0.9%)	15.8 (10.2%)	18.0 (11.4%)	38.2 (1.0%)
GHGs (Greenhouse Gases)							
CO ₂ (Carbon Dioxide)	240,158	4,029,296	2,582.1	5,164.2 (2.2%)	56,806.2 (23.7%)	64,552.5 (26.9%)	136,851.3 (3.4%)
CH ₄ (Methane)	28.6	1,478.8	14.1	28.2 (98.6%)	310.2 (1,085%)	352.5 (1,233%)	747.3 (50.5%)
N ₂ O (Nitrous Oxides)	8.4	169.0	0.05	0.1 (1.2%)	1.1 (13.1%)	1.3 (14.9%)	2.7 (1.6%)
CO ₂ eq (Global Warming Potential) ³	243,362	4,112,744	2,893.7	5,787.4 (2.4%)	63,661.4 (26.2%)	72,342.5 (29.7%)	153,366.1 (3.7%)

¹ Source: Kleinfelder (2014)

² %increase over CIAA

³ GWP (Global Warming Potential/Carbon Dioxide Equivalent [CO₂eq]) for CO₂ = 1, CH₄ = 21, and N₂O = 310.

Air resources also include visibility, which can be degraded by regional haze caused in part by sulfur, nitrogen, and particulate emissions. Based on trends identified during 2000-2009, visibility has improved slightly near the analysis area on the haziest and clearest days. Blue-shaded circles in Figure 3 indicate negative deciview (dv) changes, which mean that people can see more clearly at greater distances.

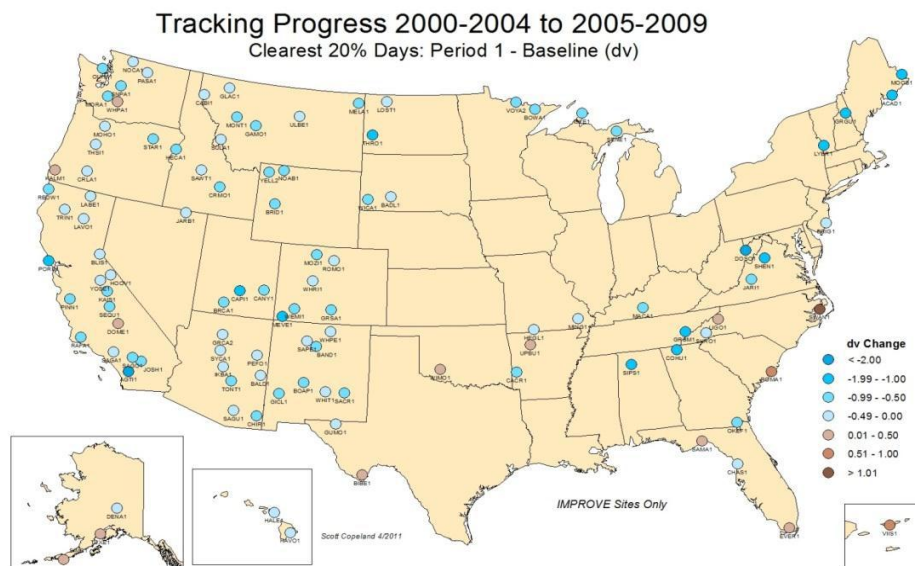
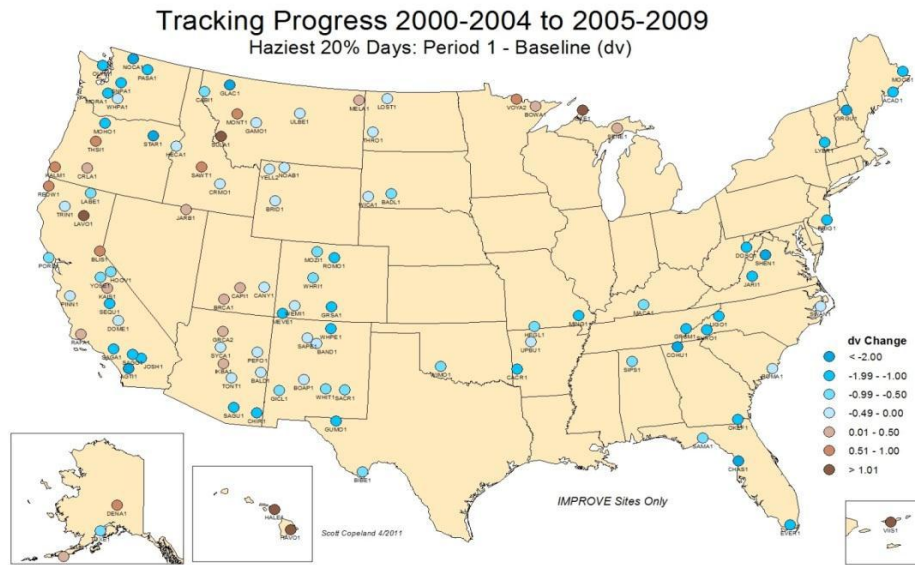


Figure 3. Visibility trends on haziest and clearest days, 2000-2009 (IMPROVE 2011).

Climate Change/Greenhouse Gasses

Climate change is defined by the Intergovernmental Panel on Climate Change (IPCC) as “a change in the state of the climate that can be identified (e.g., using statistical tests) by changes in the mean and/or the variability of its properties, and persist for an extended period, typically decades or longer. It refers to any change in climate over time, whether due to natural variability or as a result of human activity” (IPCC 2007).

The Intergovernmental Panel on Climate Change (Climate Change SIR^D 2010) states, “Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level.” Global average temperature has increased approximately 1.4°F since the early 20th century (Climate Change SIR 2010). Warming has occurred on land surfaces, oceans and other water bodies, and in the troposphere (lowest layer of earth’s atmosphere, up to 4-12 miles above the earth). Other indications of global climate change described by the IPCC (Climate Change SIR 2010) include:

- Rates of surface warming increased in the mid-1970s and the global land surface has been warming at about double the rate of ocean surface warming since then;
- Eleven of the last 12 years rank among the 12 warmest years on record since 1850;
- Lower-tropospheric temperatures have slightly greater warming rates than the earth’s surface from 1958-2005.

As discussed and summarized in the Climate Change SIR, earth has a natural greenhouse effect wherein naturally occurring gases such as water vapor, CO₂, methane, and N₂O absorb and retain heat. Without the natural greenhouse effect, earth would be approximately 60°F cooler (Climate Change SIR 2010). Current ongoing global climate change is caused, in part, by the atmospheric buildup of greenhouse gases (GHGs), which may persist for decades or even centuries. Each GHG has a global warming potential that accounts for the intensity of each GHG’s heat trapping effect and its longevity in the atmosphere (Climate Change SIR 2010). Increased GHG emissions of CO₂, methane, N₂O, and halocarbons since the start of the industrial revolution have substantially increased atmospheric concentrations of these compounds compared to background levels. At such elevated concentrations, these compounds absorb more energy from the earth’s surface and re-emit a larger portion of the earth’s heat back to the earth rather than allowing the heat to escape into space than would be the case under more natural conditions of background GHG concentrations.

A number of activities contribute to the phenomenon of climate change, including emissions of GHGs (especially carbon dioxide and methane) from fossil fuel development, large wildfires, activities using combustion engines, changes to the natural carbon cycle, and changes to radiative forces and reflectivity (albedo) due to soot deposition and other surface changes. It is important to note that GHGs will have a sustained climatic impact over different temporal scales due to their differences in global warming potential (described above) and lifespans in the atmosphere. For example, CO₂ may last 50 to 200 years in the atmosphere while methane has an average atmospheric life time of 12 years (Climate Change SIR, 2010).

With regard to statewide GHG emissions, Idaho ranks in the lowest decile when compared to all states. The estimate of Idaho’s 2011 GHG emissions of 28.5 million metric tons (MMt) of

^D Although the Climate Change SIR was developed for oil and gas leasing activities in Montana, North Dakota, and South Dakota, conclusions from broader scale analyses/findings are applicable in Idaho.

carbon dioxide equivalent (CO₂e) accounted for approximately 0.43% of the U.S. GHG emissions (WRI 2014).

Some information and projections of impacts beyond the project scale are becoming increasingly available. Chapter 3 of the Climate Change SIR describes impacts of climate change in detail at various scales, including the state scale when appropriate. The following summary characterizes potential changes identified by the EPA (EPA 2014a) that are expected to occur at the regional scale, where the Proposed Action and its alternatives could occur. The EPA identifies Idaho as part of the Northwest region (EPA 2014a):

- The region is expected to experience warmer temperatures with less snowfall.
- Temperatures are expected to increase more in winter than in summer, more at night than in the day, and more in the mountains than at lower elevations.
- Earlier snowmelt means that peak stream flow would be earlier, weeks before the peak needs of ranchers, farmers, recreationalists, and others. In late summer, rivers, lakes, and reservoirs would be drier.
- More frequent, more severe, and possibly longer-lasting droughts are expected to occur.

Other impacts could include:

- Increased particulate matter in the air as drier, less vegetated soils experience wind erosion.
- Shifts in vegetative communities which could threaten plant and wildlife species.
- Changes in the timing and quantity of snowmelt which could affect both aquatic species and agricultural needs.

Projected and documented broad-scale changes within ecosystems of the U.S. are summarized in the Climate Change SIR. Some key aspects include:

- Large-scale shifts have already occurred in the ranges of species and the timing of the seasons and animal migrations. These shifts are likely to continue. Climate changes include warming temperatures throughout the year and the arrival of spring an average of 10 days to two weeks earlier through much of the U.S. compared to 20 years ago. Multiple bird species now migrate north earlier in the year.
- Fires, insect epidemics, disease pathogens, and invasive weed species have increased and these trends are likely to continue. Changes in timing of precipitation and earlier runoff increase fire risks.
- Insect epidemics and the amount of damage that they may inflict have also been on the rise. The combination of higher temperatures and dry conditions have increases insect populations such as pine beetles, which have killed trees on millions of acres in western U.S. and Canada. Warmer winters allow beetles to survive the cold season, which would normally limit populations; while concurrently, drought weakens trees, making them more susceptible to mortality due to insect attack.

More specific to Idaho, additional projected changes associated with climate change described in Section 3.0 of the Climate Change SIR (2010) include:

- Temperature increases are predicted to be between 3 to 5°F at the mid-21st century.

- Precipitation may increase in winter by up to 25%, remain stable during the spring and fall, and decrease by up to 25% during the summer.
- Predicted annual runoff for 2041–2060 compared to 1901–1970 is expected to remain stable.
- Wildland fire risk is predicted to continue to increase due to climate change effects on temperature, precipitation, and wind. One study predicted an increase in median annual area burned by wildland fires in southern Idaho based on a 1°C global average temperature increase to be 111%.

While long-range regional changes might occur within this analysis area, it is impossible to predict precisely when they could occur. The following example summarizing climate data for the Idaho Southwestern Valleys illustrates this point at a regional scale. A potential regional effect of climate change is earlier snowmelt and associated runoff. This is directly related to spring-time temperatures. Over a 119-year record, temperatures increased 0.08 degrees per decade (Figure 4). This would suggest that runoff may be occurring earlier than in the past. However, data from 1994-2014 indicates a 0.5 degree per decade cooling trend (Figure 5). This example is not an anomaly, as several other 20-year windows can be selected to show either warming or cooling trends. Some of these year-to-year fluctuations in temperature are due to natural processes, such as the effects of El Niños, La Niñas, and the eruption of large volcanoes. This information illustrates the difficulty of predicting actual short-term regional or site-specific changes or conditions which may be due to climate change during any specific time frame.

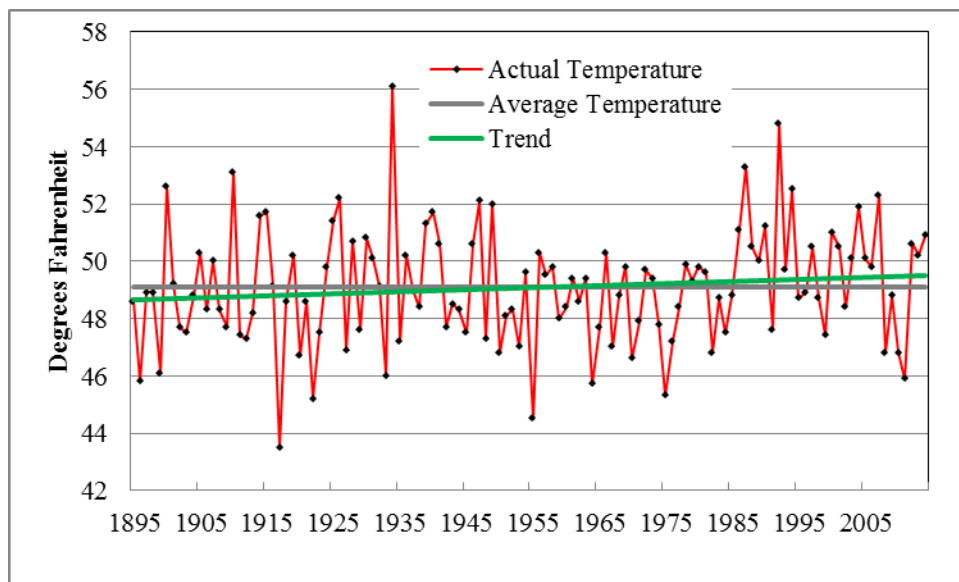


Figure 4. Regional climate summary of spring temperatures (March-May) for Idaho Southwestern Valleys, from 1895-2014. (Source: NOAA website <http://www.ncdc.noaa.gov/oa/climate/research/cag3/wn.html>)

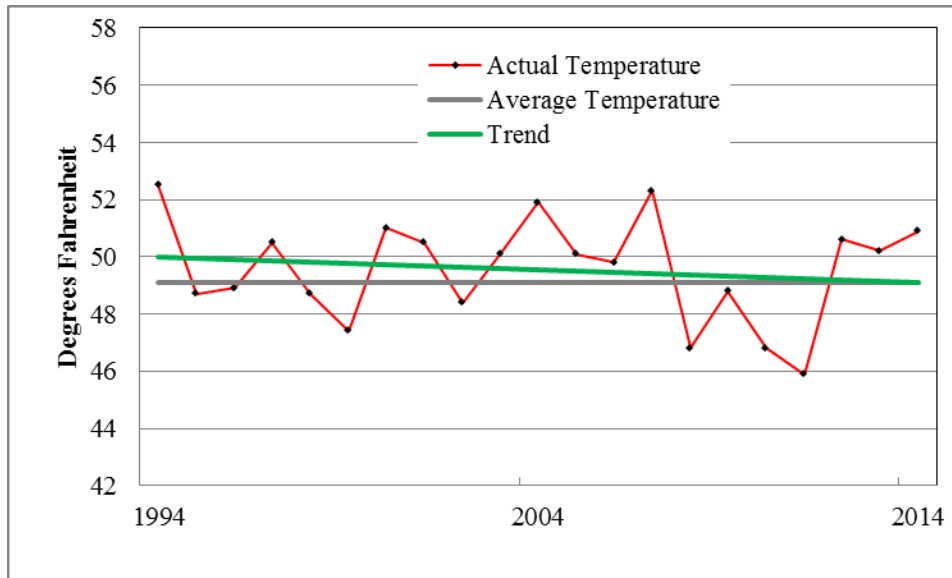


Figure 5. Regional climate summary of spring temperatures (March-May) for Idaho Southwestern Valleys, from 1994-2014. (Source: NOAA website <http://www.ncdc.noaa.gov/oa/climate/research/cag3/wn.html>)

3.4.2 Environmental Consequences – Air Resources

Impacts to air resources are based on the RFDS created for this document (Table 2, Appendix 1).

3.4.2.1 General Discussion of Impacts

Air Quality

Potential impacts of development could include increased airborne soil particles blown from new well pads or roads; exhaust emissions from drilling equipment, compressors, vehicles, and dehydration and separation facilities; as well as potential releases of GHGs and VOCs during drilling or production activities. The amount of increased emissions cannot be precisely quantified at this time since it is not known for certain how many wells might be drilled, the types of equipment needed if a well were to be completed successfully (e.g., compressor, separator, dehydrator), or what technologies may be employed by a given company for drilling any new wells. The degree of impact would also vary according to the characteristics of the geologic formations from which production occurs, as well as the scope of specific activities proposed in an APD. Oxides of nitrogen, carbon monoxide, volatile organic compounds, carbon dioxide, and methane are the most common emissions from a typical well (Green River, Wyoming; Table 6). The Kleinfelder report provides estimated pollutants for wells in three locations (San Juan, Uinta/Piceance, and Upper Green River basins). This analysis uses the Upper Green River values which represent the upper end of pollution production in the examples. The majority of pollution occurs during the production phase, where fugitive emissions (e.g., leaking pipes and valves) and dump valves (used to control the amount of fluid in the product) are the primary sources.

Climate Change/Greenhouse Gases

Sources of GHGs associated with development of lease parcels include construction activities, operations, and facility maintenance in the course of oil and gas exploration, development, and production. Estimated GHG emissions are discussed for these specific aspects of oil and gas activity because the BLM has direct involvement in these steps. Anticipated GHG emissions are based on emissions calculators developed by air quality specialists at the BLM National Operations Center in Denver, Colorado, based on a typical well in Green River Wyoming (Table 6).

3.4.2.2 Alternative A

Air Quality

Two new State lease wells and associated infrastructure would have minor adverse impacts on air quality over the long term. Small increases in nitrogen oxides (2%), carbon monoxide (0.1%), sulfur dioxide (<0.01%), and particulate matter (0.4%) would occur annually (Table 6). Good AQI values would likely predominate; however, well emissions could slightly increase the number of moderate AQI days especially during inversions. There would be negligible decreases in visibility, primarily within 1-2 miles of the wells.

Climate Change/Greenhouse Gases

Emissions from two new wells on State leases would increase Payette County's annual carbon dioxide equivalent production by 2.4% (Table 6).

3.4.2.3 Alternative B

Air Quality

Twenty-two new BLM lease wells and associated infrastructure would have moderate adverse impacts on air quality over the long term. Increases in nitrogen oxides (22%), carbon monoxide (1.4%), sulfur dioxide (0.02%), and particulate matter (4.5%) would occur annually (Table 6). The percent of days rated good AQI could decrease, especially during inversions. There would be minor decreases in visibility, primarily within 1-2 miles of the wells.

Climate Change/Greenhouse Gases

Twenty-two new wells on BLM leases would increase Payette County's annual carbon dioxide equivalent production by 26.2% (Table 6).

3.4.2.4 Alternative C

Air Quality

Twenty-five new BLM lease wells and associated infrastructure would have moderate adverse impacts on air quality over the long term. Controlled surface use stipulations could reduce some pollutants when or where they are in effect (e.g., the winter use restriction CSU-4 would reduce or eliminate some pollutants [e.g., PM₁₀] between December 1 and March 31; minimizing disturbance of fragile soils could reduce dust over the long term). Increases in nitrogen oxides (25%), carbon monoxide (1.6%), sulfur dioxide (0.03%), and particulate matter (5.1%) would occur annually (Table 6). The percent of days rated good AQI could decrease, especially during inversions. There would be minor decreases in visibility, primarily within 1-2 miles of the wells.

Climate Change/Greenhouse Gases

Twenty-five new wells on BLM leases would increase Payette County's annual carbon dioxide equivalent production by 29.7% (Table 6).

3.4.3 Mitigation

The BLM encourages industry to incorporate and implement BMPs to reduce impacts to air quality and climate change by reducing emissions, surface disturbances, and dust from field production and operations. Measures may also be required as COAs on permits by either the BLM or IDEQ. The BLM also manages venting and flaring of gas from federal wells as described in the provisions of Notice to Lessees (NTL) 4A, Royalty or Compensation for Oil and Gas Lost.

Some of the following measures could be imposed at the development stage:

- flare or incinerate hydrocarbon gases at high temperatures to reduce emissions of incomplete combustion;
- install emission control equipment of a minimum 95% efficiency on all condensate storage batteries;
- install emission control equipment of a minimum 95% efficiency on dehydration units, pneumatic pumps, produced water tanks;
- operate vapor recovery systems where petroleum liquids are stored;
- use Tier II or greater, natural gas or electric drill rig engines;
- operate secondary controls on drill rig engines;
- use no-bleed pneumatic controllers (most effective and cost effective technologies available for reducing volatile organic compounds (VOCs));
- operate gas or electric turbines rather than internal combustions engines for compressors;
- use nitrogen oxides (NO_x) emission controls for all new and replaced internal combustion oil and gas field engines;
- water dirt and gravel roads during periods of high use and control speed limits to reduce fugitive dust emissions;
- perform interim reclamation to re-vegetate areas of the pad not required for production facilities and to reduce the amount of dust from the pads.
- co-locate wells and production facilities to reduce new surface disturbance;
- use directional drilling and horizontal completion technologies whereby one well provides access to petroleum resources that would normally require the drilling of several vertical wellbores;
- operate gas-fired or electrified pump jack engines;
- install velocity tubing strings;
- use cleaner technologies on completion activities (i.e. green completions), and other ancillary sources;
- use centralized tank batteries and multi-phase gathering systems to reduce truck traffic;
- forward looking infrared (FLIR) technology to detect fugitive emissions; and
- perform air monitoring for NO_x and ozone (O₃).

Specifically with regard to reducing GHG emissions, Section 6.0 of the Climate Change SIR identifies and describes in detail commonly used technologies to reduce methane emissions from natural gas production operations. Technologies discussed in the Climate Change SIR and as summarized in Table 7 (reproduced from Table 6-2 in Climate Change SIR), display common methane emission technologies reported under the EPA Natural Gas STAR Program and associated emission reduction, cost, maintenance, and payback data.

Table 7. Selected methane emission reductions reported under the EPA Natural Gas STAR Program.

Source Type / Technology	Annual Methane Emission Reduction ¹ (Mcf/yr)	Capital Cost Including Installation (\$1,000)	Annual Operating and Maintenance Cost (\$1,000)	Payback (Years or Months)	Payback Gas Price Basis (\$/Mcf)
Wells					
Reduced emission (green) completion	7,000 ²	\$1 – \$10	>\$1	1 – 3 yr	\$3
Plunger lift systems	630	\$2.6 – \$10	NR	2 – 14 mo	\$7
Gas well smart automation system	1,000	\$1.2	\$0.1 – \$1	1 – 3 yr	\$3
Gas well foaming	2,520	>\$10	\$0.1 – \$1	3 – 10 yr	NR
Tanks					
Vapor recovery units on crude oil tanks	4,900 – 96,000	\$35 – \$104	\$7 – \$17	3 – 19 mo	\$7
Consolidate crude oil production and water storage tanks	4,200	>\$10	<\$0.1	1 – 3 yr	NR
Glycol Dehydrators					
Flash tank separators	237 – 10,643	\$5 – \$9.8	Negligible	4 – 51 mo	\$7
Reducing glycol circulation rate	394 – 39,420	Negligible	Negligible	Immediate	\$7
Zero-emission dehydrators	31,400	>\$10	>\$1	0 – 1 yr	NR
Pneumatic Devices and Controls					
Replace high-bleed devices with low-bleed devices					
End-of-life replacement	50 – 200	\$0.2 – \$0.3	Negligible	3 – 8 mo	\$7
Early replacement	260	\$1.9	Negligible	13 mo	\$7
Retrofit	230	\$0.7	Negligible	6 mo	\$7
Maintenance	45 – 260	Negl. to \$0.5	Negligible	0 – 4 mo	\$7
Convert to instrument air	20,000 (per facility)	\$60	Negligible	6 mo	\$7
Convert to mechanical control systems	500	<\$1	<\$0.1	0 – 1 yr	NR
Valves					
Test and repair pressure safety valves	170	NR	\$0.1 – \$1	3 – 10 yr	NR
Inspect and repair compressor station blowdown valves	2,000	<\$1	\$0.1 – \$1	0 – 1 yr	NR

Source Type / Technology	Annual Methane Emission Reduction ¹ (Mcf/yr)	Capital Cost Including Installation (\$1,000)	Annual Operating and Maintenance Cost (\$1,000)	Payback (Years or Months)	Payback Gas Price Basis (\$/Mcf)
Compressors					
Install electric compressors	40 – 16,000	>\$10	>\$1	>10 yr	NR
Replace centrifugal compressor wet seals with dry seals	45,120	\$324	Negligible	10 mo	\$7
Flare Installation	2,000	>\$10	>\$1	None	NR

Source: Multiple EPA Natural Gas STAR Program documents. Individual documents are referenced in Climate Change SIR (2010).

¹ Unless otherwise noted, emission reductions are given on a per-device basis (e.g., per well, per dehydrator, per valve, etc).

² Emission reduction (Mcf = thousand cubic feet of methane) is per completion, rather than per year.

NR = not reported

3.4.4 Cumulative Impacts – Air Resources

Cumulative impacts to air resources are based on the RFDS created for this document (Appendix 1), RFDS for Hamilton and Willow fields, and the actions discussed below.

3.4.4.1 Scope of Analysis

The CIAA includes the airshed associated with Ada, Baker, Canyon, and Payette counties. Because of prevailing wind patterns, changes in Baker County air quality would affect Payette County and impacts from Payette County air quality would dissipate at the eastern side of Ada County. The analysis period covers the 10-year lease period; however, pollutants are reported by their annual production levels.

3.4.4.2 Current Conditions and Effects of Past and Present Actions

Because of a large population base (615,335 people in 2013), Ada and Canyon counties contribute substantial amounts of nitrogen oxides (79%), PM₁₀ (83%), volatile organic compounds (75%), hazardous air pollutants (87%), and GHG (80%) to the four-county total pollution (Table 6). Baker County, with a relatively small population (16,018 people in 2013) and large area (3,068 mi² compared with 2,047 mi² for the other three counties combined), accounts for 71% of methane production, while other pollutant contributions vary from 7-24% of totals. The majority of growth during the 10-year period is expected to occur in Ada and Canyon counties; therefore, pollutant contributions from growth-related activities (e.g., construction, vehicle emissions, dust, and manufacturing) in these counties would be expected remain similar or increase proportionately more than Baker and Payette counties.

3.4.4.3 Reasonably Foreseeable Future Actions

An estimated 53 wells could come into production in the Hamilton (33,400 acres) and Willow (7,000 acres outside the proposed lease area) fields (Map 1). These wells would contribute from <0.01-3.4% of most pollutants; however, they would cause a 51% increase in methane production annually. AM Idaho (Alta Mesa's Idaho subsidiary) is constructing a hydrocarbon liquid treatment (dehydrator) facility (4 miles south of New Plymouth, Idaho), an ancillary

processing facility (1 mile east of New Plymouth), and associated pipelines from wells to the facilities. AM Idaho has applied for an IDEQ air quality permit for the facilities. Typical pollutants include NO_x, CO, particulate matter, HAP, and VOCs; however, the levels are unknown.

3.4.4.4 Alternative A – Cumulative Impacts

Two additional wells in the proposed lease area would have negligible additive impacts to air quality and GHG pollutants over the long term. Wells in the Hamilton and Willow fields and gas processing facilities would have minor (e.g., 3.7% CO₂ eq increase in CIAA) to major (51% methane increase in CIAA) additive impacts (Table 6), whereas, with the exception of methane gas, growth-related activities would account for the majority of pollutant increases.

3.4.4.5 Alternative B– Cumulative Impacts

Twenty-two wells in the proposed lease area would have negligible additive impacts to air quality and most GHG pollutants over the long term and would account for a 1.5% increase in methane over current levels (Table 6). Pollutants from other sources would be as described in Alternative A (Section 3.4.4.4).

3.4.4.6 Alternatives C and D – Cumulative Impacts

Twenty-five wells in the proposed lease area would have negligible additive impacts to air quality and most GHG pollutants over the long term and would account for a 1.6% increase in methane over current levels (Table 6). Pollutants from other sources would be as described in Alternative A (Section 3.4.4.4).

3.5 Water Resources

3.5.1 Affected Environment – Water Resources

Surface Hydrology and Water Quality

Surface water quality in the planning area is variable due to the highly erratic discharge and moderately to highly erosive nature of the geologic parent material and soils. Perennial streams retain water year-round and have variable flow regimes. Big Willow (0.8 miles) and Little Willow (5 miles) creeks, perennial streams in the proposed lease area, are not directly associated with proposed lease parcels. Intermittent streams flow during the part of the year when they receive sufficient water from springs, ground water, or surface sources such as snowmelt or storm events. Ephemeral streams flow only in direct response to precipitation and snowmelt. Ephemeral and intermittent streams (approximately 22 miles) occur in the proposed lease area with 8.2 miles directly associated with federal mineral estate. The Bolton and Patton irrigation canals parallel the north side of Little Willow Creek and the McIntyre and Nelson canals parallel on the south side. These canals remove the majority of water from Little Willow Creek during the irrigation season.

The National Wetland Inventory mapping identifies approximately 56 acres of wetland and riparian areas that are associated with perennial streams, canals, and ponds (Map 5). There are two springs and one seep associated with federal mineral estate. There are three ponds

associated with federal mineral estate and seven other ponds in the proposed lease area. The ponds are fed by intermittent/ephemeral streams or irrigation runoff and are typically used as livestock water sources.

Big Willow Creek has an EPA approved temperature total maximum daily level (TMDL) that is not being met (IDEQ 2014). Little Willow Creek below Paddock Valley Reservoir was rated as Unassessed Waters (IDEQ 2014). In 2007, Little Willow Creek suspended sediment levels ranged from 10-165 mg/L. High levels (>30 mg/L) were associated with the irrigation season (May 1 – September 30) and IDEQ recommended a target of 22 mg/L during that period to support cold water aquatic beneficial uses.

There are 352 acres of 100-year floodplain associated with Little Willow and Big Willow creeks and an ephemeral drainage; however, only acre is associated with federal mineral estate.

The lease parcels are located within four hydrologic unit code (HUC) 6 watershed subbasins: Little Willow Creek (HUC 1705012208), Big Willow Creek (HUC 1705012207), Payette River-Snake River (HUC 1705012209), and Jacobsen Gulch – Snake River (HUC 1705011502) (Table 8). The acreage federal mineral reserve comprises between 0.06% (Payette River – Snake River) and 6.2% (Little Willow Creek) of each watershed.

Table 8. Acres and percentage of Level 6 HUC watersheds associated with federal mineral estate and Little Willow Creek lease area, Payette County, Idaho.

Watershed		Federal Mineral Reserve		Total Lease Area	
Name	Acres	Acres	% Watershed	Acres	% Watershed
Little Willow Creek	98,464	6,094	6.2	14,182	14.4
Big Willow Creek	98,919	84	0.08	694	0.7
Payette River – Snake River	177,466	106	0.06	629	0.4
Jacobsen Gulch – Snake River	91,054	67	0.07	139	0.2

Ground Water

The quality and availability of ground water varies greatly across Idaho. Residents in Payette County commonly get their ground water from aquifers consisting of unconsolidated, alluvial valley-fill materials, typically sand and gravel deposits. Alluvial aquifers occur in terrace deposits and within the floodplains, and along the channels of larger streams, tributaries, and rivers, and are important sources of ground water. Based on 41 wells in the lease area authorized by IDWR, typical domestic supply wells in the area are between 37-405 feet deep with standing water occurring at 5-330 feet and production occurring between 7-533 feet. Well water is typically used for domestic, livestock, and irrigation purposes.

Nitrate is present in shallow ground water beneath the Payette Valley at concentrations that occasionally exceed the drinking water standard of 10 milligrams per liter (mg/L; IDEQ 2012). Arsenic has been detected in exceedance of the drinking water standard of 0.010 mg/L. Fluoride has been detected occasionally at concentrations that exceed the drinking water standard of 4

mg/L, and dissolved iron and manganese have exceeded the secondary standards of 0.3 mg/L and 0.05 mg/L, respectively.

3.5.2 Environmental Consequences – Water Resources

Impacts to water resources are based on the RFDS created for this document (Table 2, Appendix 1).

3.5.2.1 General Discussion of Impacts

Surface Hydrology and Water Quality

The magnitude of the impacts to water resources would be dependent on the specific activity, season, proximity to waterbodies, location in the watershed, upland and riparian vegetation condition, effectiveness of mitigation, and the time until reclamation success. Surface disturbance effects typically are localized, short-term, and occur from implementation through vegetation reestablishment. As acres of surface-disturbance increase within a watershed, so could the effects on water resources.

Oil and gas exploration and development could cause the removal of vegetation, soil compaction, and soil disturbance in uplands within the watershed, 100-year floodplains of non-major streams, and non-riparian, ephemeral waterbodies. The potential effects from these activities could be accelerated erosion, increased overland flow, decreased infiltration, increased water temperature, channelization, and water quality degradation associated with increased sedimentation, turbidity, nutrients, metals, and other pollutants. Erosion potential can be further increased in the long term by soil compaction and low permeability surfacing (e.g. roads and well pads) which increases the energy and amount of overland flow and decreases infiltration, which in turn changes flow characteristics, reduces ground water recharge, and increases sedimentation and erosion.

Water withdrawals for drilling operations would lead to reduced aquifer water levels, reduced streamflow, and impacts to some water quality parameters associated with stream flow. These impacts to water quality may include increased water temperature, decreased concentrations of dissolved oxygen, and increases in other parameters such as salinity levels, sodium adsorption ratio, and introduction of drilling pollutants (e.g., organic acids, alkalis, diesel oil, crankcase oils, hydrochloric and hydrofluoric acids, chloride, sodium, calcium, magnesium, potassium, polycyclic aromatic hydrocarbons, lead, arsenic, barium, antimony, sulfur, zinc, and naturally occurring radioactive materials) (TEEIC 2014). Ground water removal would result in a depletion of flow in nearby streams and springs if the aquifer is hydraulically connected to such features. Typically produced water from conventional oil and gas wells is from a depth below useable aquifers.

Ground Water

Spills, drilling fluids, fracking fluids, or produced fluids could potentially impact surface and ground water resources over the long term. Drilling in the proposed lease area would most likely pass through useable ground water. Potential impacts to ground water resources could occur if proper cementing and casing programs are not followed. This could include loss of well integrity, failed cement, surface spills, and/or the loss of drilling, completion, and hydraulic

fracturing fluids into groundwater. It is possible for chemical additives used in drilling activities to be introduced into ground water producing formations without proper casing and cementing of the well bore. Concentrations of these additives also vary considerably and are not always known because different mixtures can be used for different purposes in gas development and even in the same well bore. Changes in porosity or other properties of the rock being drilled can result in the loss of drilling fluids. When this occurs, drilling fluids can be introduced into ground water in the absence of proper cementing and casing. Site specific conditions and drilling practices determine the probability of this occurrence and determine the ground water resources that could be impacted. Some or all of the produced water from these leases is likely to be injected in wells for disposal. Improper construction and management of reserve and evaporation pits could degrade ground water quality through leakage and leaching.

The potential for adverse ground water impacts caused from hydraulic fracturing are currently being investigated by the EPA. Currently, water use to drill one well ranges between 1 and 6 million gallons. In fracturing a well, companies have estimated that generally they use a ratio of 0.5% hydraulic chemical fluid mix to 1.5 million gallons of water. That translates to a minimum of 5,000 gallons of chemicals into one well for every 1.5 million gallons of water used to fracture a well. In addition to changing the producing formations' physical properties by increasing the flow of water, gas, and/or oil around the well bore; hydraulic fracturing can also introduce chemical additives into the producing formations. Production zones generally do not contain fresh water. Types of chemical additives used in drilling activities may include acids, hydrocarbons, thickening agents, lubricants, and other additives that are operator and location specific. These additives are not always used in these drilling activities and some are likely to be benign such as bentonite clay and sand. Concentrations of these additives also vary considerably because different mixtures can be used for different purposes in oil and gas development and even in the same well bore. If contamination of aquifers from any source occurs, changes in ground water quality could impact springs and residential wells that are sourced from the affected aquifers.

If contamination of freshwater aquifers from oil and gas development occurs, changes in ground water quality could impact springs and residential wells if these springs and residential wells are sourced from the same aquifers that have been affected. Direct impacts to surface water would likely be greatest shortly after the start of construction activities and would likely decrease in time due to natural stabilization, and reclamation efforts. Ground water impacts would be less evident and occur on a longer time scale. Construction activities would occur over a relatively short period (commonly less than a month); however, natural stabilization of the soil can sometimes takes years to establish to the degree that would adequately prevent accelerated erosion caused by compaction and removal of vegetation. Spills or produced fluids (e.g., saltwater, oil, fracking chemicals, and/or condensate in the event of a breach, overflow, or spill from storage tanks) could result in contamination of the soil onsite, or offsite, and may potentially impact surface and ground water resources in the long term.

Not all wells resulting from an APD would employ fracturing, and water consumption would be temporary. Oil and gas wells are cased and cemented at a depth below all usable water zones; consequently impacts to water quality at springs and residential wells are not expected.

However, faulty cementing or well casing could result in methane migration to upper zones. Should hydrocarbon or associated chemicals for oil and gas development in excess of EPA/IDEQ standards for minimum concentration levels migrate into culinary water supply wells, springs, or systems, it could result in these water sources becoming non-potable.

For federal mineral estate wells, Onshore Order #2 requires that the proposed casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones. For State-regulated wells, IDAPA 20.07.02 provides similar requirements from initial drilling to plugging. Authorization of exploration and production activities would require full compliance with local, state, and federal directives and stipulations that relate to surface and ground water protection.

3.5.2.2 Alternative A

Surface Hydrology and Water Quality

Not leasing 6,349 acres would limit surface disturbance in those areas. Vegetation and soil conditions would be maintained over the long term minimizing sediment input to waterbodies from 6% of the Little Willow Creek watershed and negligible (0.2%) portions of other watersheds (Table 8). Development of two wells and associated infrastructure (7 acres of disturbance) would have negligible (~0.001% of Little Willow Creek watershed) direct impacts to surface hydrology. Negligible (>0.25 miles from stream) to moderate (<200 feet from stream) short-term sediment inputs could occur to Little Willow Creek until vegetation reestablishment occurs. Produced water and pollutants carried by natural events would cause adverse water quality impacts where pollutants reach Little Willow Creek. The longevity and severity of the impacts would depend on the type of pollutant. Ground water depletion could adversely affect Little Willow Creek.

Ground Water

Direct development and production ground water impacts would not occur on 6,349 acres. Development of two wells could have negligible (well casings are effectively implemented) to major (well casings fail and persistent, toxic pollutants are introduced) adverse effects to ground water quality in the Little Willow Creek drainage. Up to 15 domestic and agricultural wells in the immediate vicinity and downstream could be affected.

3.5.2.3 Alternative B

Surface Hydrology and Water Quality

Leasing 6,349 acres with NSO and NSSO stipulations would limit surface disturbance in those areas. Vegetation and soil conditions would be maintained over the long term minimizing sediment input to waterbodies from 6% of the Little Willow Creek watershed and negligible (0.2%) portions of other watersheds (Table 8). Development of 22 wells and associated infrastructure (77 acres of disturbance) would have negligible to minor direct impacts to surface hydrology, primarily where roads collect and convey water rather than allowing infiltration. Impacts from sediment inputs would be similar to Alternative A (Section 3.5.2.2); however, four additional wells could be drilled near Little Willow and Big Willow creeks. Produced water and pollutant impacts could affect Little Willow and Big Willow creeks. Four additional wells would increase the probability of adverse water quality and ground water depletion impacts.

Ground Water

Direct development and production ground water impacts would not occur on 6,349 acres. Development of 22 wells could have negligible (well casings are effectively implemented) to major (persistent, toxic pollutants are introduced) adverse effects to ground water quality in the Little Willow and Big Willow drainages; however, the number of wells could increase the probability of a pollution event. Up to 54 domestic and agricultural wells in the immediate vicinity and downstream could be affected.

3.5.2.4 Alternative C

Surface Hydrology and Water Quality

Leasing 6,349 acres with CSU stipulations would limit surface disturbance in those areas. Vegetation and soil conditions would be maintained over the long term minimizing sediment input to waterbodies from 6% of the Little Willow Creek watershed and negligible (0.2%) portions of other watersheds (Table 8). Development of 25 wells and associated infrastructure (88 acres of disturbance) would have similar hydrology and sediment impacts to Alternative B (Section 3.5.2.3); however, 500 foot CSU buffers from waterbodies would help limit sediment inputs (Map 5). Fewer surface occupancy restrictions would allow wells to be placed further from streams relative to Alternative B. Produced water and pollutant impacts could affect Little Willow and Big Willow creeks; however, CSU buffers would reduce the probability of pollutants reaching waterbodies.

Ground Water

Direct development and production ground water impacts could occur on <6,162 acres. Development of 25 wells could have similar impacts to those described in Alternative B (Section 3.5.2.3); however, the probability of a pollution event could be slightly greater.

3.5.3 Mitigation

Mitigation measures that minimize the total area of disturbance, control wind and water erosion, reduce soil compaction, maintain vegetative cover, control nonnative species, and expedite rapid reclamation (including interim reclamation) would maintain surface hydrology processes and water quality. Methods to reduce erosion and sedimentation could include: reducing surface disturbance acres; installing and maintaining adequate erosion control; proper road design, road surfacing, and culvert design; road/infrastructure maintenance; use of low water crossings; and use of isolated or bore crossing methods for waterbodies and floodplains. In addition, applying mitigation to maintain adequate, undisturbed, vegetated buffer zones around waterbodies and floodplains could reduce sedimentation and maintain water quality. Lining ponds would minimize seepage of potentially toxic chemicals into ground water. Closing and rehabilitating ponds promptly, when no longer functional or needed, would exposure to toxic substances. Appropriate well completion, the use of Spill Prevention Plans, and Underground Injection Control (UIC) regulations would mitigate ground water impacts. Site-specific mitigation and reclamation measures would be described in the COAs.

Known water bearing zones in the lease area are protected by drilling requirements and, with proper practices, contamination of ground water resources would be unlikely (IOGCC 2013b; IDAPA 20.07.02). Casing along with cement would be extended well beyond fresh-water zones

to insure that drilling fluids remain within the well bore and do not enter ground water. Potential impacts to ground water at site specific locations are analyzed through the NEPA review process at the development stage when the APD is submitted. This process includes geologic and engineering reviews and onsite oversight to ensure that cementing and casing programs are adequate to protect all downhole resources. All water used would have to comply with State water rights regulations and a source of water would need to be secured by industry that would not harm senior water rights holders.

3.5.4 Cumulative Impacts – Water Resources

Cumulative impacts to water resources are based on the RFDS created for this document (Appendix 1), RFDS for Hamilton and Willow fields, and the actions discussed below.

3.5.4.1 Scope of Analysis

The 65,700-acre CIAA includes portions of the Little Willow Creek, Big Willow Creek, and Payette River-Snake River (north of the Farmers Canal) Level 6 HUC watersheds downstream of the eastern boundary of the proposed lease area and the majority of the Payette Valley Flow System (Map 5). This represents an area that could potentially be affected by surface runoff and ground water pollutants. The analysis period covers the 10-year lease period; however, pollutants would be expected to travel at different rates in different systems. Surface pollutants could reach the downstream portion of the CIAA relatively quickly once they enter flowing waters. Conversely, ground water pollutants would likely take considerably longer to travel beyond the source.

3.5.4.2 Current Conditions and Effects of Past and Present Actions

Sagebrush and other shrubs (11,067 acres; 17% of CIAA), exotic annuals (13,716 acres; 21%), agriculture (35,404 acres; 54%), urban (2,271 acres; 3%), and perennial bunchgrass (2,452 acres; 4%) comprise the majority of cover types. Roads, ploughed fields and exotic annual cover provide the lowest degree of watershed protection. Watershed stability is at greatest risk where these cover types occur in moderate or highly erosive soils. Most agricultural lands are irrigated with surface (from canals) or ground water.

There are approximately 56.5 miles of perennial streams (Payette River, Little Willow and Big Willow creeks) and all are influenced by irrigation outtake and return flows. There are approximately 2,000 acres of wetland, riparian, and pond habitat. Stream and riparian conditions are similar to those described in Section 3.6.1. The 9,760 acres of floodway are primarily associated with the Payette River. There are 1,305 water wells, most occur south of the Payette River or northwest of the confluence of Little Willow Creek and the Payette River.

Potential pollutant sources include pesticides from agricultural and urban areas, chemicals from industrial and retail businesses, runoff from roadways, and 15 existing oil and gas wells. The amount of pollutants from these sources is unknown.

3.5.4.3 Reasonably Foreseeable Future Actions

At least 37 additional oil and gas wells could be drilled (1 well/640 acres in the portions of the Willow and Hamilton fields in the CIAA). Pollutants from development and production would be as described in Section 0. Wildfires, as described in other sections, would be expected to cause short-term increases in sediment inputs and watershed instability until vegetation cover is reestablished.

3.5.4.4 Alternative A – Cumulative Impacts

Surface Hydrology and Water Quality

Not leasing 6,349 acres (10% of the CIAA) would have negligible to minor additive benefits to surface hydrology and water quality. Wildfires, exotic annuals, and ploughed fields would potentially affect much larger areas. Rain events in these areas could result in minor to major sediment inputs to floodways and streams. Burned riparian areas would recover within five years, but upland areas would likely become dominated by exotic annuals and remain susceptible to erosion events. The extent of ground water withdrawal for irrigation is unknown. Irrigation water removal and return water pollutants (both agricultural and urban) would annually have moderate to major adverse water quality impacts to perennial streams. Development and production at up to 37 oil and gas wells would have negligible surface hydrology impacts, but could have negligible (no spills occur, spills are largely contained on site, or spills are non-pollutant materials) to major (spills affect domestic water supplies with toxic pollutants) adverse water quality impacts.

Ground Water

Not leasing 6,349 acres would have negligible additive ground water benefits. Agricultural activities (e.g., ground water pumping, pollution input from leaking wells) would have minor (seasonal reductions in water availability, pollution stays in immediate vicinity of well) to major (increased use of ground water during extended drought periods, pollutants migrate from well to domestic water supplies) adverse impacts to ground water availability and quality over the short and long term. Pollutants from industrial and urban sources could have minor to major short or long term adverse impact to ground water quality. Development and production at up to 37 oil and gas wells would have negligible (well casings are effectively implemented, ground water is not used to produce gas) to major (persistent, toxic pollutants are introduced; ground water is used to produce gas) adverse effects to ground water availability and quality.

3.5.4.5 Alternatives B and C – Cumulative Impacts

Surface Hydrology and Water Quality

Leasing 6,349 acres with some surface stipulations and development of 22-25 wells and associated infrastructure would have negligible to minor additive impacts to surface hydrology and increased sediment input. Minor to moderate additive water quality impacts from produced water and pollutants could occur. Impacts from other activities would be as described in Alternative A (Section 3.5.4.4).

Ground Water

Development and production at 22-25 wells would have negligible (well casings are effectively implemented) to major (persistent, toxic pollutants are introduced) adverse additive effects to ground water availability and quality. Impacts from other activities would be as described in Alternative A (Section 3.5.4.4).

3.6 Wildlife/Special Status Animals

3.6.1 Affected Environment – Wildlife/Special Status Animals

Habitats support a variety of special status wildlife including southern Idaho ground squirrel (SIDGS), a candidate species under the ESA, 14 other mammal species, 17 bird species, three amphibian species, and three reptile species (Appendix 4). Habitat conditions are described for representative groups of animals (migratory birds, southern Idaho ground squirrels, big game, and amphibians/fish).

Vegetation composition has been shaped by physical site characteristics such as aspect, soils, precipitation, and disturbances (primarily wildland fire, livestock grazing, and agricultural development). Fires and long-term spring grazing have reduced the diversity and abundance of native perennial forbs and grasses, favoring exotic annuals. The resulting conditions (Section 3.2.1) generally provide poor quality habitat for most species. Shrub-dominated communities comprise 32% of cover, annual and perennial grasslands and agriculture characterize the remainder. Although these disturbances have occurred on all aspects, native vegetation is less resilient on the hotter, drier southerly aspects than the cooler, moister northerly aspects; therefore, southerly aspects are dominated by exotic grasses and northerly aspects are dominated by native vegetation. This has resulted in major habitat fragmentation. The proposed lease area has approximately 36.6 miles of roads and trails (1.5 miles/mi²). Access to many roads is restricted by private landowners; therefore, the majority of roads have minor fragmentation and disturbance impacts.

Migratory Birds and Raptors

The analysis area encompasses over 15,000 acres; therefore, bird habitat will be analyzed at a landscape scale, where birds are typically affected on a population level (Paige and Ritter 1999). Because the area lacks contiguous sagebrush habitat and suitable cover of native perennial bunchgrasses and forbs, it does not support stable populations of sagebrush-obligate species such as greater sage-grouse^E. These sagebrush obligates require a large mosaic of big sagebrush cover

^E Based on 2014 sage-grouse habitat maps developed by BLM and IDFG and lek monitoring data, the proposed lease area is approximately 1 mile from R2 (sagebrush with annual grass understory) habitat, 5 miles (isolated habitat) from key (sagebrush with perennial grass understory) and preliminary general habitat [areas outside of breeding habitat that support important seasonal (winter, summer, fall habitat, migration corridors) or year-round habitat for sage-grouse], and 6.5 miles (contiguous habitat) from key and preliminary priority [areas that have the highest conservation value (breeding, nesting, brood-rearing) to maintaining sage-grouse populations] sage-grouse habitats. The closest leks are 9.5 (active) or 10.5 (inactive) miles away.

types, inter-mixed with native bunchgrasses and forbs. Other sagebrush obligates including Brewer's sparrow, sage sparrow, and sage thrasher could be present during the spring and summer; however, these species are also sensitive to fragmented sagebrush habitats and they occur in low numbers.

Grassland associated species such as long-billed curlew, western meadowlark, vesper sparrow, and horned lark utilize short grassland habitat for nesting, breeding, and brood-rearing. Long-billed curlew populations have declined in nearby areas (i.e., Long-billed Curlew Habitat Area of Critical Environmental Concern 8-20 miles southeast of the lease area) primarily due to recreational activities and development. Between 1966 and 2012, vesper sparrow, western meadowlark, and horned lark populations in Idaho have also declined. Northern harrier, red-tailed hawk, ferruginous hawk, golden eagle, American kestrel, and turkey vulture are common birds of prey that hunt for insects, small mammals, birds, and carrion throughout the area, year-round or during annual migrations.

Riparian associated species including warblers, flycatchers, and sparrows utilize shrub and tree dominated habitat along Little Willow and Big Willow creeks for nesting, brood rearing, and foraging. Little Willow Creek provides marginal quality habitat that is substantially influenced by agricultural activities and is primarily characterized by herbaceous-dominated vegetation with scattered stands of cottonwood, willow, and Russian olive. Big Willow Creek provides good quality habitat that is characterized by a fairly contiguous cottonwood overstory with interspersed willow and herbaceous communities or understories.

Resident (e.g., golden eagle, red-tailed hawk, Cooper's hawk) and migratory (e.g., burrowing owl, short-eared owl, prairie falcon) birds use the area for nesting, brood rearing, foraging, and migration. Surveys for raptor nests have not occurred in or adjacent to the lease parcels.

Although fires have degraded much of the habitat, it does provide suitable habitat for a variety of prey species including small mammals, song birds, reptiles, and insects.

Burrowing Mammals

Southern Idaho Ground Squirrel - Southern Idaho ground squirrels inhabit drainage bottoms and adjacent gradual slopes in small scattered populations, below approximately 3,200 feet elevation. Historically, SIDGS primarily occupied sandier soils that supported big sagebrush/bunchgrass/forb communities with antelope bitterbrush (Yensen 1991). In the absence of a reliable and nutritious diet provided by native grasses and forbs, SIDGS are subject to the highly variable productivity and nutritional value of exotic annuals. When annual precipitation is relatively low, poor productivity of exotic annuals may not provide enough nutritional sustenance to enable squirrels to store enough fat to survive their long over-wintering period (torpor). The availability of forbs plays a crucial role in the torpor persistence of juvenile male ground squirrels (Barrett 2005). Torpor begins in late June or early July when vegetation begins to dehydrate and desiccate, and lasts until late January or early February when squirrels emerge from their burrows.

Currently, SIDGS habitat is dominated by exotic annuals and provides limited sagebrush cover with perennial herbaceous understories needed to support a stable squirrel population; medusahead is common throughout the area, especially on south aspects, and is indigestible for

SIDGS due to its high silica content. The majority of known SIDGS colonies occur on adjacent private lands (IDFG 2013). There is a paucity of SIDGS monitoring data for the area, but it is likely that SIDGS utilize habitat on the northerly aspects of public land to some degree, as these areas tend to support more native vegetation.

Pygmy Rabbit - The pygmy rabbit is the smallest North American rabbit species (USFWS 2010). On September 30, 2010, the USFWS concluded that the pygmy rabbit does not currently warrant listing under the ESA (USFWS 2010). This species is typically found in areas of tall, dense sagebrush cover and are considered a sagebrush-obligate species because they are highly dependent on sagebrush to provide both food and shelter throughout the year (Green and Flinders 1980; Katzner and Parker 1997). Pygmy rabbits have been found from 2,900 feet to over 6,000 feet in elevation in southwestern Idaho. Although low sagebrush density and prevalence of cheatgrass provides marginal habitat, pygmy rabbits have been observed in the proposed lease area.

Big Game

The area provides limited winter habitat for antelope and mule deer as south slopes are typically dominated by annual grasses and do not support adequate shrub cover. Mule deer inhabiting the area are part of the Weiser-McCall Population Management Unit (IDFG 2010b). Deer winter range has been adversely impacted by wildfire, as fire has reduced the abundance of important shrub species such as bitterbrush and sagebrush that deer depend on for food and thermal cover during the winter. The spread of noxious weeds also poses a threat to mule deer winter range. The area may provide marginally better elk winter range because of their grass species dietary preferences even during winter. Elk inhabiting the area are part of the Weiser River Zone delineated by the Idaho Department of Fish and Game (IDFG). Threats to elk winter range habitat include noxious weed invasion such as yellow starthistle and whitetop (IDFG 2010a). Big game may avoid the area during late summer, fall, and winter due to lack of shrub cover on southerly slopes, reduced abundance of perennial grasses and forbs, and off-highway vehicle (OHV) activity. The proposed lease area occurs on the western edge of identified winter range and is characterized by regular human disturbance associated with low density rural residences and associated agricultural activities. Approximately 77% of the proposed lease area and 94% of lands associated with federal mineral reserves are considered big game winter range (Map 6).

Aquatic Species

Perennial and intermittent water sources provide breeding and brood-rearing habitat for a variety of amphibian, reptile, and fish species. Degraded water quality (e.g., increased temperature levels, sediment loads, and agricultural pollutants) and irrigation dewatering, especially in Little Willow Creek, may limit the suitability or productivity for some species. Adjacent uplands provide important foraging areas for amphibians and reptiles. Some species (e.g., western toad) may move up to 3.9 miles (1.2 miles on average) from breeding areas and occupy areas away from water sources (Bull 2006).

Bats

Up to 11 special status bat species could occur in the area. The species rely on natural (e.g., tress, cliffs, and caves) or manmade (e.g., buildings) structures for roosting and hibernating.

They are typically nocturnal insect foragers in a variety of habitats including forest, shrub, grass, or agriculture dominated areas. Little brown bats typically forage up to 0.6 miles from a roost area; however, ranges diminish to predominantly 0.1 miles in July when females are lactating and insect densities are high (Henry et. al. 2002).

3.6.2 Environmental Consequences – Wildlife/Special Status Animals

Impacts to wildlife are based on the RFDS created for this document (Table 2, Appendix 1).

3.6.2.1 General Discussion of Impacts

The use of standard lease terms and stipulations could minimize, but not preclude impacts to wildlife. Oil and gas development which results in surface disturbance could directly and indirectly impact aquatic and terrestrial wildlife species. The scale, location, and pace of development, combined with implementation of mitigation measures and the specific tolerance of the species to human disturbance all influence the severity of impacts to wildlife species and habitats.

Direct impacts would include disturbance or interruption of activities, vehicle collisions, powerline collisions and electrocutions, nest abandonment, habitat avoidance, displacement of wildlife species resulting from human presence and increased predation. Disturbances (e.g., natural gas development activities, OHV use) can adversely affect songbird habitat use (Ingelfinger 2001; Barton and Holmes 2007). The impacts were greatest within 330 feet of high traffic volume roads where $\leq 60\%$ population reductions occurred even when traffic volumes were less than 12 vehicles/day. Noise and human activities can disrupt key activities such as breeding displays, brooding, and foraging. Road mortality can be influenced by travel speed, species abundance, species susceptibility, coincidence of vehicle and animal activity, and proximity to key habitats. Hawks and owls are more susceptible to electrocution especially where wingspans are wider than the line spacing, whereas quail, pheasants, ducks, and songbirds are more susceptible to collision hazards (Bevanger 1998).

Indirect impacts would include loss or reduction in suitability of habitat, improved habitat for undesirable (non-native) competitors, species or community shift to species or communities more tolerant of disturbances, barriers to species migration and dispersal, and habitat fragmentation. Increases in invasive and noxious weed species that displace native plant species would adversely affect habitat structure and quality, reducing habitat suitability for most species while favoring species that tolerate poor habitat quality.

Migratory Birds and Raptors

Construction and development activities can effect migratory bird's nesting season from as early as February 15; however, activity from March 15th through August 15th poses the greatest impact to migratory birds by disrupting breeding behavior and breeding success. Nest occupancy for some species (e.g., golden eagle and ferruginous hawk) may not be affected during the production phase (Wallace 2014). Response to disturbances during winter, when birds are stressed by environmental conditions could adversely affect survivability. During the winter, 97% of raptors flushed when humans on foot were within 385 feet and 38% flushed

when vehicles were within 245 feet (Holmes et. al. 1993). Take of bald and golden eagles or any other migratory species would not be anticipated; however, take may occur indirectly as a result of vehicle collisions and other related actions associated with development.

Burrowing Mammals

Construction of well pads and roads could directly eliminate habitat. Vehicle traffic and increased raptor perch sites associated with powerlines and other infrastructure would increase mortality. Reduced habitat quality (e.g., increases in invasive annuals and noxious weeds) and increased fragmentation would adversely affect SIDGS annual body condition, survival rates, and population viability (Barrett 2005) and pygmy rabbit diet quality and cover (Larrucea and Brussard 2008).

Big Game

Well pad and road construction would reduce available habitat. Roads and associated disturbances would reduce suitability of adjacent habitat. Short and long-term responses to development and production activities vary by species and habitat type (Hebblewhite 2008). Mule deer avoided areas when development was initiated and did not become acclimated to activities as time passed; instead, avoidance distances increased as development progressed (Sawyer et. al. 2006). The distance animals were displaced increased from 1.7 to 2.3 miles away from well pads during the first three years of development. Mule deer densities decreased 46% in the developed area over a four year period. Animals forced to winter at higher elevations with increased snow levels would have reduced survival rates. Habitat loss and fragmentation were better predictors of antelope winter habitat use than distance to well pads and roads (Beckman et. al. 2008). In areas with relatively limited pre-development disturbance, major ungulate responses (e.g., avoidance or abandonment) could occur when oil and gas development of 0.3–1.3 wells/mi² and 0.3-1.6 linear road miles/mi² occurred (Hebblewhite 2008).

Aquatic Species

Noise and lights from development activities could disrupt breeding behavior annually. Road mortality would affect species that spend part of their life cycle in terrestrial habitats (Carr 2002). Pollutants discharged into aquatic systems could cause behavioral changes, mutations, or mortality at all life stages (Lefcort et. al. 1998).

Bats

Lights and noise associated with human activities could cause short-term disruptions in foraging behavior and success. Persistent disturbances near roost sites could cause avoidance or abandonment. Bat responses to disturbances vary by species, and some species (e.g., big brown bat) may be more tolerant than others (Duchamp et. al. 2004). Infrastructure (e.g., powerlines) could cause increased collision mortality. Actions that reduce insect productivity (e.g., reduced habitat quality, pollutants) would reduce available prey.

3.6.2.2 Alternative A

Migratory Birds and Raptors

Development of two wells and associated infrastructure would have minor adverse short- and long-term disturbance, mortality, and habitat quality reduction impacts. An additional 0.5 miles

of roads would cause a negligible increase in fragmentation and disturbance. Low levels of localized disturbance would occur throughout the year over the long term. Up to 7 acres of habitat would be directly eliminated and use would be reduced on 70 acres because of disturbance.

Burrowing Mammals

Development of two wells and associated infrastructure would have minor adverse short- and long-term mortality and habitat quality reduction impacts. An additional 0.5 miles of roads and powerlines would cause a minor increase in SIDGS mortality. Up to 7 acres of habitat would be directly eliminated. Depending on the location of roads and well pads, impacts to pygmy rabbits could be negligible (development >0.35 miles from sagebrush) to major (development in an occupied sagebrush stand).

Big Game

Depending on their location and animal responses, development of two wells and associated infrastructure would have minor (wells adjacent to existing disturbances that animals have become habituated to) to major (at least one well on the east side of the lease area that effectively keeps animals from using the remainder of the lease area) disturbance impacts. Changes in habitat fragmentation (beyond the disturbance component) and habitat quality would have minor adverse long-term impacts. Animals habituated to low levels of disturbance could be displaced to adjacent agricultural areas over the short term when moderate or greater development disturbances occur during winter use periods.

Aquatic Species

Depending on their location, development of two wells and associated infrastructure would have negligible (>0.5 miles from wetland/riparian habitat with no possibility of pollution input) to moderate (<0.1 miles from wetland/riparian habitat with potential pollution input) disturbance and pollutant impacts.

Bats

Development of two wells and associated infrastructure would have negligible (located >0.75 miles from roost sites) to minor (located <0.5 miles from roost sites) adverse short- and long-term disturbance, mortality, and prey reduction impacts.

3.6.2.3 Alternative B

No direct habitat loss (77 acres of well pads and roads) would occur on the 6,349 acre federal mineral estate until the FRMP was implemented; however, loss could occur in adjacent areas that are developed prior to FRMP implementation. Stipulations derived from the FRMP could help mitigate impacts described below.

Migratory Birds and Raptors

Development of 22 wells and associated infrastructure would have moderate to major adverse short- and long-term disturbance, mortality, and habitat quality reduction impacts. An additional 5.5 miles of roads would cause a major increase in fragmentation and disturbance because regular activity would occur in most of the proposed lease area. Moderate levels of disturbance

would occur throughout the year and lease area over the long term. Up to 77 acres of habitat would be directly eliminated and use would be reduced on 770 acres because of disturbance.

Burrowing Mammals

Development of 22 wells and associated infrastructure would have moderate to major adverse short- and long-term mortality and habitat quality reduction impacts. An additional 5.5 miles of roads and powerlines would cause minor to moderate increases in SIDGS mortality. Up to 77 acres of habitat could be directly eliminated. Habitat quality changes would adversely affect both species; however, impacts to pygmy rabbits would be greater because of their year-round activity patterns. Depending on the location of roads and well pads, impacts to pygmy rabbits could be negligible (development >0.35 miles from sagebrush) to major (development in an occupied sagebrush stand).

Big Game

Development of 22 wells (1 well/mi²) and associated infrastructure would have moderate to major adverse short- and long-term disturbance, habitat fragmentation, and habitat quality reduction impacts. Road densities would increase to 1.7 miles/mi², but vehicle traffic throughout the area would increase substantially, especially during the development phase. Existing unmaintained roads would be upgraded and become potentially more accessible throughout the year and to a greater number of users, increasing disturbance and fragmentation. Access restrictions by private landowner could limit disturbances to development and production activities. The activities would make the area unsuitable winter range for animals that do not become habituated to higher disturbance levels. Animals habituated to low levels of disturbance could be displaced to adjacent agricultural areas over the short and long (until development is completed) term when moderate or greater development disturbances occur during winter use periods. Increases in invasive and noxious weed species would further degrade habitat; however, improved access that helps fire suppression efforts could reduce fire size and associated habitat loss.

Aquatic Species

Development of 22 wells and associated roads would have minor to moderate adverse short- and long-term disturbance, mortality, and pollutant impacts. Ponds and streams downslope from well pads would be most susceptible to surface-flow pollutant impacts. Contaminated ground water that connects to streams could have negligible (short-term, non-toxic pollutants) to major (persistent toxicant introduced) adverse impacts on up to 5.8 miles of perennial streams in the proposed lease area and potentially downstream areas.

Bats

Development of 22 wells and associated infrastructure would have minor (disturbance located >0.75 miles from roost sites) to moderate (located <0.5 miles from roost sites) adverse short- and long-term disturbance, mortality, and prey reduction impacts. Disturbance tolerant species would be less affected than intolerant species. Reduced insect production associated with decreased habitat quality would adversely affect all species over the long term.

3.6.2.4 Alternative C

Migratory Birds and Raptors

Development of 25 wells and associated infrastructure would have similar disturbance, mortality, and habitat quality reduction impacts as described in Alternative B (Section 3.6.2.3). An additional 6.8 miles of roads would cause a major increase in fragmentation because roads would occur throughout the lease area. Up to 88 acres of habitat would be directly eliminated and use would be reduced on 875 acres because of disturbance. Winter and spring surface use restrictions would reduce or eliminate lessee-related disturbance and mortality impacts during critical periods; however, increased access by non-lessee users could offset those benefits. No surface occupancy within 0.5 miles of heron rookeries would minimize lessee-related disturbances and habitat impacts.

Burrowing Mammals

Development of 25 wells (1 well/mi²) and associated infrastructure would have moderate adverse short- and long-term mortality and habitat quality reduction impacts. An additional 6.8 miles of roads and powerlines would cause minor to moderate increases in SIDGS mortality. Avoidance of burrow sites would eliminate direct impacts to those important areas, but up to 88 acres of foraging habitat could be eliminated and infrastructure that increases disturbance and raptor perch sites could adversely affect adjacent burrow sites. Habitat quality change impacts would be as described in Alternative B (Section 3.6.2.3). Controlled surface use restrictions would benefit burrowing mammals that occur in restricted areas by reducing (winter and spring restrictions that coincide with critical periods of pygmy rabbits) or eliminating (spring restrictions that coincide with SIDGS active periods) lessee-related disturbances.

Big Game

Development of 25 wells and associated infrastructure would have moderate to major adverse short- and long-term disturbance, habitat fragmentation, and habitat quality reduction impacts. Road densities would increase to 1.8 miles/mi², but controlled surface use restrictions would reduce or eliminate lessee-related disturbances during the winter. If exceptions are granted to surface use restrictions, then disturbances from development and production activities could have minor (1-2 one-day exceptions during the course of a winter) to major (exceptions throughout the winter) short and long terms impacts similar to those described in Alternative B (Section 3.6.2.3). If exceptions are minimalized, animals would be less likely to move to adjacent agricultural lands (as described in Alternative B, Section 3.6.2.3). Other road-related and habitat quality impacts would be as described in Alternative B (Section 3.6.2.3). Overall winter range suitability could be similar to Alternative B or slightly improved depending on how animals respond to infrastructure and wells despite surface use restrictions.

Aquatic Species

Surface occupancy and pollutant restrictions would minimize or eliminate development and production related disturbance, mortality, and pollutant impacts to key aquatic habitat. Development of 25 wells and associated roads would have minor to moderate adverse short- and long-term disturbance and mortality impacts to species that utilize areas >500 feet from riparian habitats.

Bats

Development of 25 wells and associated infrastructure would have similar disturbance, mortality, and prey reduction impacts described in Alternative B (Section 3.6.2.3). Spring controlled surface use restrictions and riparian habitat buffers would benefit bats by reducing or eliminating activities in important foraging and roosting areas.

3.6.3 Mitigation

Measures would be taken to prevent, minimize, or mitigate impacts to terrestrial and aquatic species from exploration and development activities. Lease stipulations to mitigate impacts on wildlife would be placed on leases for crucial winter range (timing limitation), migratory birds and raptors (controlled surface use), burrowing mammals (lease notice), Endangered Species Act (Section 7 Consultation), and fragile soils (lease notice) stipulations which would protect additional habitat. Prior to authorization, activities would be evaluated on a case-by-case basis, and the project could be subject to additional mitigative COAs. Mitigation could include rapid revegetation, project relocation (<660 feet), or pre-disturbance wildlife species surveying. If oil and gas development is proposed in suitable habitat for threatened or endangered species, consultation with the USFWS would occur to determine if additional terms and conditions would need to be applied. Adherence to Avian Powerline Interaction Committee (APLIC) guidelines could help reduce or eliminate electrocution mortality.

The following operational measures would help reduce wildlife impacts. If drilling operations require evaporation ponds, cover ponds with nets to exclude migratory birds. Ponds should be checked frequently (daily) for trapped wildlife. Report trapped wildlife (live and dead) to BLM, FWS, and IDFG no later than 24 hours of initial discovery. Lighting at sites should be directed specifically to where needed to minimize potential impacts to wildlife and turned off when not in use. To minimize predators or nuisance wildlife at work sites, place an appropriately sized dumpster with lid at each site during construction activities and check/dump as needed. Prohibit workers from bringing dogs to well sites during drilling and site maintenance actions to avoid predation/harassment of wildlife. Enforce speed limits of 25 MPH on spur roads and well pads to reduce wildlife collision risk.

3.6.4 Cumulative Impacts - Wildlife/Special Status Animals

Cumulative impacts to wildlife are based on the RFDS created for this document (Appendix 1) and the actions discussed below.

3.6.4.1 Scope of Analysis

The 81,518-acre CIAA (13% BLM, 4% State, and 83% private) includes a 3-mile buffer around the proposed lease area and north of the Payette River (Map 6). This area was selected because it corresponds to typical foraging or dispersal movements or disturbance response distances for a variety of species. The lease period of 10 years will be used for the temporal analysis limit because most disturbance impacts are associated with lease activities and site reclamation would address some longer term impacts such as habitat quality and fragmentation.

3.6.4.2 Current Conditions and Effects of Past and Present Actions

The CIAA supports the same species described above. Migratory birds and raptors are common throughout the area. Pygmy rabbits are uncommon and SIDGS are present throughout most of the area. About 60% of the area, primarily in the north and east, is considered big game winter range. Approximately 36 miles of perennial streams and river provide marginal to suitable habitat for aquatic species.

Vegetative Cover and Habitat Conditions – Sagebrush and other shrubs (26,809 acres; 33% of CIAA), exotic annuals (29,807 acres; 37%), agriculture/urban (16,531 acres; 20%), and perennial bunchgrass (7,936 acres; 10%) comprise the majority of cover types. Sagebrush understory conditions vary by slope and aspect, with steeper and north facing slopes generally having a more intact native understory than gentler and south facing slopes. Approximately 79% of the area has burned one or more times, with most of the fires occurring during the 1980s. Where shrubs have become re-established in areas burned prior to 1990, exotic annuals are dominant or co-dominant in the understory. Conditions on the Little Willow (14 miles) and Big Willow (11.8 miles) creeks are similar to those described above. The Payette River (9.8 miles) is characterized by cottonwood and willow overstories with shrub and herbaceous understories.

Disturbance – The CIAA is characterized by low density rural development. Disturbance factors include agricultural activities, OHV use, hunting, and other recreational uses. Nonresident access is restricted in much of the CIAA by private landowners. Recreational use is greatest during the spring and fall.

Roads – There are approximately 197 miles of roads (1.5 miles/mi²) including 9.3 miles of highway, 45 miles of maintained roads, and 142.7 miles of unmaintained roads. The majority of maintained roads are associated with developed areas on Little Willow and Big Willow creeks or the Payette River. There are 9 miles of designated trails east of the Big Willow and Stone Quarry roads junction. Within big game winter range, approximately 1,172 acres are designated as closed to motorized vehicles, 127 acres are designated as open, and the remainder are designated limited to existing roads.

Powerlines - The CIAA includes two transmission lines (26.5 miles) and numerous distribution lines (74.7 miles). Transmission lines are built to APLIC standards; however, most distribution lines are not. Therefore, both types represent collision hazards, but only the distribution lines represent electrocution hazards. The majority of distribution lines are within 0.3 miles of Little Willow and Big Willow creeks or the Payette River.

Livestock Grazing – The CIAA includes all or portions of 10 BLM-administered livestock grazing allotments (32,550 acres; 40% of CIAA). The allotments are used primarily during the spring, with some season long (e.g., Kauffman) or winter (e.g., Sand Hollow) use occurring. Undeveloped private lands outside BLM allotments and agricultural fields (fall-winter) are also used for grazing.

3.6.4.3 Reasonably Foreseeable Future Actions

Oil and Gas Lease Development and Production – There are 11 existing or planned wells (Map 1, IOGCC 2014). There are approximately 4,960 acres of State-managed mineral resources, some of which have been leased, but drilling has not been initiated. Exploration is currently being conducted in the eastern two-thirds of the CIAA. Approximately 15 wells could be drilled in the Willow Field between the Payette River and the proposed lease area.

Agricultural/Residential Development – Development causes a direct loss of wildlife habitat and activities associated with the developed areas can cause disturbance over the long term. Limited residential development would occur on the western boundary of the CIAA. Negligible increases in agricultural development would be expected because of limited water resources. If water resources decline, some fields could go fallow, creating marginal wildlife habitat. New development would require additional powerlines and other infrastructure.

Recreation Uses – Off-highway vehicle use would be expected to remain static (e.g., increased access restrictions imposed by private landowners) or increase (e.g., in response to increasing populations) over time. Approximately 384 acres along the Payette River are managed by the IDFG in the Payette River Wildlife Management Area to benefit wildlife and sportsmen.

Wildfire – Although not planned events, wildfires would be expected to periodically occur and may increase in size and frequency in response to climate change. Loss of shrubs and increased dominance of exotic annuals in burned areas would reduce habitat structure and quality over the short term. Adverse effects would persist over the long term where native perennials don't re-establish.

3.6.4.4 Alternative A – Cumulative Impacts

Two additional wells and associated infrastructure would have negligible additive disturbance, mortality, habitat quality reduction, and fragmentation impacts over the short and long term. Ongoing activities and existing roads and powerlines would cause minor (away from developed areas) to moderate (adjacent to developed areas along Little Willow and Big Willow creeks) disturbance and mortality impacts throughout the CIAA. Livestock grazing, especially in consistent spring use areas, would favor exotic annuals and early seral native and non-native species throughout undeveloped portions of the CIAA. Development and production activities of at least 26 wells would have moderate disturbance, mortality, and fragmentation impacts over the short and long term on approximately 20% of the CIAA. The majority of wells would be within 0.5 miles of perennial streams, but only nine wells would be within 1.5 miles of big game winter range. Additional agricultural and residential development would have minor disturbance, habitat loss, and fragmentation impacts over the long term. Depending on size, wildfires would have minor to major long-term adverse impacts on habitat quality and fragmentation.

3.6.4.5 Alternatives B and C – Cumulative Impacts

Development and production activities at 22 to 25 wells in the proposed lease area would have moderate additive disturbance, mortality, habitat quality reduction, and fragmentation impacts

over the short and long term. Timing and other restrictions in Alternative C wells would help reduce spatial and temporal overlap with other disturbances (e.g., other oil and gas development, recreation use) and habitat quality and fragmentation impacts. Impacts from ongoing and foreseeable future actions would be as described in Alternative A (Section 3.6.4.4).

3.7 Cultural Resources

3.7.1 Affected Environment – Cultural Resources

The BLM is responsible for identifying, protecting, managing, and enhancing cultural resources which are located on public lands, or that may be affected by BLM undertakings on non-Federal lands, in accordance with the National Historic Preservation Act (NHPA) of 1966, as amended. The procedures for compliance with the NHPA are outlined in regulation under 36 CFR 800. Cultural resources include archaeological, historic, and architectural properties, as well as traditional life-way values and/or traditional cultural properties important to Native American groups.

Common prehistoric archaeological site types in Payette County include rock art, artifact scatters, burials, and tool manufacture. Common historic archaeological sites are the remains of farmsteads, homesteads, depressions, artifact scatters, foundations, cabins, sheepherder camps, and historic inscriptions.

A literature search (Level I or Class I) of Idaho State Historic Preservation Office records and a 2001 Class III survey (498 acres associated with Idaho Power right-of-way) identified 11 sites within a one-mile search radius. Records were reviewed to determine what types and numbers of known cultural resources are present within or adjacent to the lease area. Seven sites are prehistoric, three sites are historic, and one site includes prehistoric and historic artifacts. None of the sites were considered eligible for listing on the National Register of Historic Places (NRHP).

3.7.2 Environmental Consequences – Cultural Resources

Impacts to cultural resources are based on the RFDS created for this document (Table 2, Appendix 1).

3.7.2.1 General Discussion of Impacts

Ground disturbing activities could alter the characteristics of an eligible property by diminishing the integrity of the property's location, design, setting, materials, workmanship, feeling, or association. Other effects to cultural resources from surface disturbance activities include the destruction, damage, or alteration to all or part of the cultural resource and diminishing the property's significant historic features as a result of the introduction of visual, atmospheric, or audible elements. Activities that adversely affect adjacent vegetation conditions and soil stability could increase erosion that would degrade or destroy site context.

3.7.2.2 Alternative A

Development of two wells and associated infrastructure could adversely affect cultural resources on private lands.

3.7.2.3 Alternative B

Leasing with a NSO stipulation would preclude ground disturbing impacts to cultural resources on 6,349 acres. Changes in vegetation condition and erosion could have negligible long-term impacts for eligible properties adjacent to ground disturbing activities.

3.7.2.4 Alternative C

Compliance with Cultural Resources S-2 would ensure that no sites would be disturbed or destroyed before they are inventoried and evaluated for eligibility for listing in the NRHP. Historic and archeological sites that are eligible for listing in the National Register of Historic Places or potentially eligible to be listed would either be avoided or have the information in the sites extracted through archeological data recovery prior to surface disturbance.

3.7.3 Mitigation

Specific mitigation measures including site avoidance, excavation, or data recovery would have to be determined when site-specific development proposals are received. Most surface-disturbing situations for cultural resources would be avoided by project redesign or relocation. Unavoidable, significant properties would be site-specifically mitigated with concurrence with the State Historic Preservation Office prior to implementation of a project.

3.7.4 Cumulative Impacts – Cultural Resources

Because the alternatives would cause none to negligible impacts to cultural resources, cumulative impacts will not be discussed.

3.8 Paleontological Resources

3.8.1 Affected Environment – Paleontological Resources

According to Section 6301 of the Paleontological Resource Protection Act of 2009 Omnibus Public Lands Bill, Subtitle D, SEC. 6301, paleontological resources are defined as “any fossilized remains, traces, or imprints of organisms, preserved in or on the earth’s crust, that are of paleontological interest and that provide information about the history of life on earth” (Paleontological Resource Protection Act of 2009 Omnibus Lands Bill, Subtitle D, SEC. 6301-3612 (P.L. 59-209; 34 Stat. 225; 16 U.S.C. 431-433). Significant fossils are defined by BLM policy as including all vertebrate fossil remains and those plant and invertebrate fossils determined to be scientifically unique, on a case-by-case basis. Paleontological resources do not include archaeological and cultural resources.

The proposed lease area includes Miocene (sedimentary rocks associated with flood basalts; 5-23 million years BP) and Pleistocene and Pliocene (older sediments and sedimentary rocks, gravel, sand, and silt deposited in fans; 11,700 to 5.3 million years BP) epochs, and Quaternary (alluvial gravel, sand, and silt deposits associated with Little and Big Willow creeks; 0-2.6 million years

BP) period deposits. Paleontological surveys have not been conducted in the proposed lease area; however, a diversity of fossiliferous resources could be expected to occur and fossilized remains of horse, beaver, camel, and elephant-like animals have been found in the Glenns Ferry Formation (Erasthem-Vanir 2009).

The BLM utilizes the Potential Fossil Yield Classification (PFYC) as a planning tool for identifying areas with high potential to yield significant fossils. The system consists of numbers ranging from 1-5 (low to high) assigned to geological units, with 1 being low potential and 5 being high potential to have significant fossil resources. The potential to yield significant fossil resources is never 0. It is anticipated that most significant fossil resources are located in those geologic units with a PFYC of 3 or greater. However, significant fossil resources could be discovered anywhere. Rock units not typically fossiliferous can in fact contain fossils in unique circumstances.

The BLM classified geologic formations that have a high Potential Fossil Yield Classification (PFYC) of 3 or higher should be specifically reviewed for paleontological resources. Much of the proposed lease area falls within the Glenns Ferry Formation which has a Class 5 PFYC and should be evaluated for fossil resources before and potentially during ground-disturbing activities.

3.8.2 Environmental Consequences – Paleontological Resources

Impacts to paleontological resources are based on the RFDS created for this document (Table 2, Appendix 1). The analysis assumes that surveys conducted prior to ground disturbing activities would identify paleontological resources on the surface (see CSU 12 and LN 7).

3.8.2.1 General Discussion of Impacts

Surface-disturbing activities could potentially alter the characteristics of paleontological resources through damage, fossil destruction, or disturbance of the stratigraphic context in which paleontological resources are located, resulting in the loss of important scientific data. Identified paleontological resources could be avoided by project redesign or relocation before project approval which would negate the need for the implementation of mitigation measures. Increased public access could result in vandalism or collection of paleontological resources. Conversely, surface-disturbing activities could potentially lead to the discovery of paleontological localities that would otherwise remain undiscovered due to burial or omission during review inventories. The scientific retrieval and study of these newly discovered resources would expand our understanding of past life and environments of Idaho.

3.8.2.2 Alternative A

Infrastructure development associated with two wells could directly impact paleontological resources on up to 7 acres on private lands. Increased public access could expose areas surrounding new roads to negligible to minor vandalism or collection impacts.

3.8.2.3 Alternative B

Infrastructure associated with 22 wells would not occur on 6,349 acres of BLM-administered and split estate lands; therefore, there would be no direct impacts to paleontological resources in these areas. Direct impacts could occur on up to 77 acres of private lands where development does occur. Increased access could have negligible (private landowners restrict public access) to moderate (access is not restricted) vandalism and collection impacts.

3.8.2.4 Alternative C

Infrastructure development associated with 25 wells could directly affect up to 88 acres; however, identification and avoidance or documentation/collection would minimize these impacts. Impacts from increased access would be as described in Alternative B (Section 3.8.2.3).

3.8.3 Mitigation

The application of lease terms, the paleontological conditional surface use stipulation (CSU 11), and the paleontological lease notice (LN 7) at leasing, provides protection to paleontological resources during development. The paleontological lease notice is applied to all lease parcels, requiring a field survey prior to surface disturbance. These survey requirements could result in the identification of paleontological resources. Avoidance of significant paleontological resources or implementation of mitigation prior to surface disturbance would protect paleontological resources.

However, the application of lease terms only allows the relocation of activities up to 200 meters, unless otherwise documented in the NEPA document, and cannot result in moving the activity off lease. Specific mitigation measures could include, but are not limited to, site avoidance or excavation. Avoidance of paleontological properties would be a best management practice. However, should a paleontological locality be unavoidable, significant fossil resources must be mitigated prior to implementation of a project. These mitigation measures and contingencies would be determined when site specific development proposals are received.

3.8.4 Cumulative Impacts – Paleontological Resources

Because paleontological resource impacts would be avoided or mitigated on BLM-administered and split estate lands, cumulative impacts will not be discussed.

3.9 Recreation

3.9.1 Affected Environment – Recreation

BLM only manages recreational opportunities and experiences on BLM-administered surface lands. Recreational activities enjoyed by the public on BLM lands in the proposed lease area include hunting, hiking, and OHV activities. Benefits and experiences enjoyed by recreational users include opportunities for solitude, spending time with families, enhancing leisure time, improving sports skills, enjoying nature, and enjoying physical exercise. The 997 acres of BLM-administered lands proposed for lease have limited legal public access (i.e., no public easements or rights-of-way across private property). The lack of public access limits use of the BLM

parcels for recreational use by the general public. None of the BLM-administered lands occur in special recreation management areas (SRMAs) or recreation areas. Motorized use on BLM-administered lands is limited to existing roads and trails.

3.9.2 Environmental Consequences – Recreation

Impacts to recreation are based on the RFDS created for this document (Table 2, Appendix 1).

3.9.2.1 General Discussion of Impacts

Road construction that leads to or across BLM-administered lands would create or improve public access to those lands. However, access across private lands between public rights-of-way and public lands would still be at the discretion of the landowner. Noise and traffic associated with development and production could detract from the rural physical and social setting or disrupt some activities (e.g., hunting).

3.9.2.2 Alternative A

Infrastructure development associated with two wells would create none to negligible increases in BLM-administered land access. Public lands would be beyond the potential well sites; therefore, no new roads would be constructed to BLM-administered lands. Development and production activities would cause negligible adverse changes in user experiences.

3.9.2.3 Alternative B

Infrastructure associated with 22 wells would not occur on 6,349 acres of BLM-administered and split estate lands; therefore, there would be none to negligible increases in BLM-administered land access. Development and production activities would cause minor to moderate (e.g., activities adversely affect game species) adverse changes in user experiences.

3.9.2.4 Alternative C

Infrastructure development associated with 25 wells would create minor improvements in BLM-administered land access. Most BLM parcels have existing road access; therefore, upgrading those roads could allow better year-round access by a wider range of users. Development and production activities could cause minor to moderate (e.g., activities adversely affect game species) adverse changes in user experiences.

3.9.3 Mitigation

Because of the isolated nature of public lands in the area, no mitigation would be required.

3.9.4 Cumulative Impacts - Recreation

Because the alternatives would cause primarily none to minor impacts to recreation activities and experiences and public land access is at the discretion of private landowners, cumulative impacts will not be discussed.

3.10 Visual Resources Management

3.10.1 Affected Environment – Visual Resources Management

Visual Resource Management (VRM) is the system used to designate and manage the visual resources on public land. In the lease area, the CRMP designated 112 acres as Class III and 885 acres as Class IV (Map 7). A Class III VRM area classification means the level of change to the character of the landscape should be moderate. Changes caused by management activities should not dominate the view of the casual observer and should not detract from the existing landscape features. Any changes made should repeat the basic elements found in the natural landscape such as form, line, color and texture. A Class IV VRM area classification means that the characteristic landscape can provide for major modification of the landscape. The level of change in the basic landscape elements can be high. However, every attempt should be made to minimize the impact of these activities through careful location, minimal disturbance, and repeating the basic elements. An existing 230 kV line traverses Class III and IV lands in the northern portion of the proposed lease area. Human influences are relatively unnoticeable on the remainder of BLM-administered lands that are characterized by mixed vegetation communities, fencing, and unimproved two-track roads.

3.10.2 Environmental Consequences – Visual Resources Management

Impacts to visual resources are based on the RFDS created for this document (Table 2, Appendix 1).

3.10.2.1 General Discussion of Impacts

Disturbance of existing vegetation and creation of permanent linear (e.g., roads, powerlines) and point (e.g., well pads and structures) features would alter the form, line, color, and texture of the natural landscape.

3.10.2.2 Alternative A

Development of two wells on private lands would have no impact on VRM characteristics.

3.10.2.3 Alternative B

Development of 22 wells on private lands would have no impact on VRM characteristics.

3.10.2.4 Alternative C

Development of wells and associated infrastructure on BLM-administered lands could have negligible (Class IV) to minor (Class III) adverse impacts on visual resources. It would introduce more noticeable man-made structures to the natural environment.

3.10.3 Mitigation

All oil and gas development would implement, as appropriate for the site, BLM BMPs for VRM, regardless of the VRM class. This includes, but would not be limited to, proper site selection, reduction of visibility, minimizing disturbance, selecting color(s)/color schemes that blend with the background and reclaiming areas that are not in active use. Repetition of form, line, color and texture when designing projects would reduce contrasts between landscape and development. Wherever practical, no new development would be allowed on ridges. Overall, the goal would be to not reduce the scenic values that currently exist.

3.10.4 Cumulative Impacts – Visual Resources Management

Because the changes associated with the potential development would be in conformance with VRM guidance for Class III and IV lands, cumulative impacts will not be discussed.

3.11 Lands and Realty

3.11.1 Affected Environment – Lands and Realty

Lands and realty actions will only occur on BLM-administered surface lands. The affected environment consists of 997 acres of BLM-administered public lands (or 16% of the total acreage proposed for lease). Rights-of-way currently exist for an Idaho Power 230-kV powerline (IDI-13054; 0.53 miles long by 100 feet wide; 6.4 acres) and associated access roads (1.71 miles of roads 14 feet wide; 2.9 acres) and for the Little Willow Irrigation District's Nelson Canal (IDB-0019666; 0.12 miles) (Map 7).

3.11.2 Environmental Consequences – Lands and Realty

3.11.2.1 General Discussion of Impacts

Standard oil and gas lease terms recognize prior existing rights. Development activities could require rights-of-way that overlay and adversely affect existing rights-of-way. Rights-of-way applications would be analyzed through a NEPA process that would identify potential resource impacts which would likely be similar to impacts described in this document.

3.11.2.2 Alternative A

Development of two wells and associated infrastructure would not affect existing public lands or rights-of-way. The IDI-13054 right-of-way is >2 miles north of the proposed well sites.

3.11.2.3 Alternative B

Development of 22 wells and infrastructure outside BLM-administered mineral rights would not directly affect IDI-13054. Activity could occur within a 0.6-mile segment of the powerline corridor that occurs on private lands.

3.11.2.4 Alternative C

Development of 25 wells and associated infrastructure would have a negligible impact on IDI-13054. Roads associated with the right-of-way could be improved and used for oil and gas infrastructure which would improve access to the powerline. The powerline right-of-way occupies <1% of BLM-administered lands and occurs to the north of where infrastructure would likely occur; therefore, it could be readily avoided.

3.11.3 Mitigation

The split estate lease notice would require the lessee to attempt to work with the surface owner through execution of a Surface Use Agreement. A bond would be required, for the benefit of the surface owner, if no agreement was reached. Measures would be taken to avoid disturbance or impacts to existing rights-of-way, in the event of any oil and gas development activities. Any new "off-lease" or third party rights-of-way required across federal surface for exploration

and/or development would be subject to lands and realty stipulations to protect other resources as determined by environmental analyses. In order to protect the existing rights-of-way it is recommended that LN-7 be applied to lease parcels associated with IDI-13054 and IDB-0019666.

3.11.4 Cumulative Impacts - Lands and Realty

Because the alternatives would cause no or negligible impacts to the existing rights-of-way, cumulative impacts will not be discussed.

3.12 Livestock Management

3.12.1 Affected Environment – Livestock Management

The proposed lease area includes portions of five BLM-administered grazing allotments (Map 8). The allotments are permitted for cattle and use periods are in the spring, spring through fall, or winter (Table 9). Total allotment sizes range from 1,488 acres (Danke Allotment) to 15,643 acres (Sand Hollow Allotment), with federal mineral estate affecting 306 acres (Sand Hollow Allotment) to 1,095 acres (Danke Allotment) (Table 10). The allotments have several range improvements including fences, stock ponds, wells, and roads (Map 8). Livestock grazing is not currently permitted on 184 acres of BLM-administered lands in the proposed lease area.

Table 9. Permit information for five allotments affected by proposed Little Willow Creek lease, Payette County, Idaho.

Allotment		Permittee	Livestock		Season of Use	Permitted AUMs
Name	Number		Kind	#		
Dannke	00084	Larry Dahnke	C	150	4/1 – 5/15	58
Hashagen	00248	Wolfe Ranches	C	112	3/16 – 4/15*	114
Kauffman	00163	Randall Kauffman	C	200	4/1 – 10/10**	25
Rock Quarry Gulch	20131		C	130	4/11-8/10	115
Sand Hollow	00254	Rocky Comfort Cattle Co.	C	1,302	10/26-3/15***	1,509

*Season and numbers are not restricted to those shown above provided overuse and deterioration do not occur to the federal range.

**Livestock numbers will be coordinated between BLM and the Lessee and may vary within the permitted use period, however, AUMs may not be exceeded. Any change to the scheduled use requires prior approval.

***Season and numbers of livestock are not restricted to those shown above provided overuse and deterioration does not occur to the public lands and the use is covered by the OX CRMP.

Table 10. Federal mineral reserve acres by allotment, amount of allotment in lease area, and total allotment size (acres) for five allotments affected by proposed Little Willow Creek lease, Payette County, Idaho.

Allotment	Federal Mineral Reserve		Lease Area		Allotment Total			
	BLM	Private	BLM	Private	BLM	State	Private	Total
Dannke	269	826	269	992	496	0	992	1,488
Hashagen	198	743	198	1,619	511	0	1,901	2,412
Kauffman	57	613	57	1,335	67	0	1,770	1,837
Rock Quarry Gulch	217	824	217	1,620	563	0	1,940	2,503
Sand Hollow	59	247	59	669	4,935	603	10,105	15,643

There are 23.1 miles of allotment boundary and 3.5 miles of pasture fencing in the five allotments. Natural or reservoir water sources occur in the Hashagen and Kaufman allotments.

3.12.2 Environmental Consequences – Livestock Management

Impacts to livestock management are based on the RFDS created for this document (Table 2, Appendix 1).

3.12.2.1 General Discussion of Impacts

Standard oil and gas lease terms recognize prior existing rights. Oil and gas development would result in a loss of vegetation for livestock grazing (e.g., direct removal, introduction of unpalatable plant species), decreased vegetation palatability due to fugitive dust, disrupted livestock management practices, increased vehicle collision injuries and mortalities, altered water quality and availability, and decreased grazing capacity (Fowler and Witte 1985). These impacts would vary from short-term impacts to long-term impacts depending on the development level, reclamation success, and the type of vegetation removed.

Oil and gas development activity would reduce BLM's ability to manage livestock grazing while meeting or progressing towards meeting the Idaho Standards of Rangeland Health (USDI 1997). Development and associated disturbances could reduce available forage or alter livestock distribution which could lead to overgrazing or other localized grazing impacts. Construction of roads, especially in areas of rough topography could improve livestock distribution.

3.12.2.2 Alternative A

Development of two wells and associated infrastructure would occur outside and, therefore, would not directly affect BLM-administered allotments. Negligible impacts from fugitive dust could occur.

3.12.2.3 Alternative B

Development of 22 wells and associated infrastructure on private lands would have negligible (Sand Hollow Allotment) to minor (Hashagen and Rock Quarry Gulch allotments) vegetation loss, palatability, collision, and capacity impacts over the short and long term. Approximately 32% of the development could occur in the allotments (2,982 acres of private lands with no split estate minerals in the allotments/9,292 acres in the proposed lease area); therefore, direct habitat loss would occur on approximately 25 acres (7 wells and 1.75 miles of roads). Changes in palatability and desirable species composition adjacent to roads would depend on the amount of dust generated and the distance it travelled. Roads that cross allotment or pasture boundaries could have moderate to major disruption impacts where animals are able to freely move between use areas. Changes in water availability and quality could occur in the Hashagen and Kaufman allotments. Minor adverse rangeland health impacts could occur on BLM-administered lands, primarily in the Danke, Hashagen, and Rock Quarry Gulch allotments where BLM-administered lands make up 21-25% of the allotment within the proposed lease area.

3.12.2.4 Alternative C

Development of 25 wells and associated infrastructure on private lands would have negligible (Sand Hollow Allotment; e.g., no direct impacts, possible dust and disturbance impacts) to moderate (Danke Allotment; e.g., reduced forage capacity caused by increased weeds) vegetation loss, palatability, collision, and capacity impacts over the short and long term. Based on allotment acreages and well spacing, none (Sand Hollow Allotment) to two wells (Danke, Hashagen, and Rock Quarry Gulch allotments) could be developed. Direct loss of vegetation would be ≤ 7 acres in a given allotment and 25 acres total in the five allotments. Impacts to livestock operations, water, and rangeland health would be as described in Alternative B (Section 3.12.2.3).

3.12.3 Mitigation

Measures would be taken to prevent, minimize, or mitigate impacts to livestock grazing from exploration and development activities. Prior to authorization, activities would be evaluated on a case-by-case basis, and the project would be subject to mitigation measures. Mitigation could potentially include controlling livestock movement by maintaining fence line integrity, fencing facilities, installing cattleguards, re-vegetation of disturbed sites, and fugitive dust control.

3.12.4 Cumulative Impacts - Livestock Management

Cumulative impacts to livestock management are based on the RFDS created for this document (Appendix 1) and the actions identified below.

3.12.4.1 Scope of Analysis

The 23,891-acre CIAA includes all lands associated with the five allotments associated with proposed lease (Table 10). Allotments represent an administrative boundary that addresses most components of an individual's livestock operation. Changes in vegetation conditions outside the allotments that could indirectly affect the allotments are discussed in Soils and Vegetation Cumulative Impacts (Section 3.2.4). The lease period of 10 years will be used for the temporal analysis limit because most impacts are associated with lease activities and site reclamation.

3.12.4.2 Current Conditions and Effects of Past and Present Actions

Vegetation Conditions – Major cover types include shrubs (10,793 acres; 45% of CIAA), exotic annuals (9,511 acres; 40%), and perennial grasses (3,512 acres; 15%). Exotic annuals are the dominant cover type in the Danke, Hashagen, and Rock Quarry Gulch (southern portion allotments). All of the Danke, Hashagen, and Rock Quarry Gulch and significant portions of the Sand Hollow and Kaufman allotments burned in the 1980s. Where shrubs have recovered, exotic annuals are dominant or co-dominant with perennial species in the understory. Species composition is the most important palatability influence, with areas dominated by medusahead providing the least palatable forage except during early spring green-up. Rangeland health assessments have not been conducted on the allotments. Consistent moderate or greater livestock use during the growing period would result in downward perennial grass trends and increased exotic annuals. Perennial grasses would be less affected by dormant season use and could be maintained in the absence of other disturbances (e.g., wildfire).

Disturbance – Disturbance impacts include leaving gates open, harassing livestock, and shooting livestock. There are approximately 46 miles of roads in the allotments, but almost all are unimproved 2-tracks that require access through private lands. Non-livestock related use occurs primarily during the spring and fall by OHV users and hunters. There are existing gas wells on the Hashagen (one well) and Kauffman (two wells) allotments. There are approximately 84 miles of allotment and pasture fences.

3.12.4.3 Reasonably Foreseeable Future Actions

Oil and Gas Lease Development and Production – There are approximately 765 acres of State-managed mineral resources (679 acres in Sand Hollow Allotment, 75 acres in Hashagen Allotment, and 5 acres in Dannke Allotment), some of which may have been leased, but drilling has not been initiated. An unknown amount of private land has also been leased. One additional well could be drilled in the Kaufman Allotment and up to seven wells could be drilled in the Sand Hollow Allotment that would not affect federal mineral estate.

Wildfire – Although not planned events, wildfires would be expected to periodically occur and may increase in size and frequency in response to climate change. Conversion of perennial grass understories to exotic annuals in burned areas would reduce forage quality and availability over the long term. Loss of shrub cover would reduce soil moisture and shorten growing periods. Burned public lands are typically rested one or more growing seasons until recovery objectives are met.

3.12.4.4 Alternative A – Cumulative Impacts

Not leasing federal mineral estate would have no additive impacts. Changes in vegetation conditions caused by livestock grazing and wildfires would have moderate to major adverse impacts to livestock forage where exotic annuals replace perennials and rangeland health standards would not be met over the long term. Larger wildfires would have moderate to major short-term adverse impacts to livestock operations where post-fire rest is implemented. Recreation, OHV, and development/production would cause negligible to moderate short-term disturbance impacts. An additional eight wells and associated infrastructure would cause negligible direct forage loss and decreased forage palatability, but could cause minor to moderate decreases in vegetation conditions where increased access and use increased exotic annuals and noxious weeds.

3.12.4.5 Alternatives B and C– Cumulative Impacts

Development and production activities at 7 to 10 wells in the proposed lease area would have minor to moderate additive vegetation condition and disturbance impacts over the short and long term. Impacts from ongoing and foreseeable future actions would be as described in Alternative A (Section 3.12.4.4).

3.13 Minerals (Fluid)

3.13.1 Affected Environment – Minerals (Fluid)

The proposed lease area occurs in the Payette River Valley, at an elevation of between 2,000 and 3,000 feet. It is on the northern edge of the western Snake River Plain, an approximately 40-mile wide, northwest-trending graben structure, filled with sediments of Plio-Pleistocene Lakes Idaho and Bruneau and intercalated basalts. These sediments are referred to as the Idaho Group (Pliocene) and Payette Formation (Miocene). While there is no type section for the Payette Formation, it is described as a thick body of fresh-water and continental sediments, generally made up of ash, clay, shale, and sandstone, with an occasional lignite bed (Buwalda 1923). The sediments are known to contain organic material, including petrified tree stumps, fresh-water shells and mammalian fossils, such as ancestral horses and camels. Strata seen at Payette extend westward across the Snake River for long distances into Oregon. The Payette Formation has been measured at over 4,000 feet in a deep well at Ontario, Oregon.

The Willow and Hamilton fields have been designated by the oil industry to delineate areas believed to have a natural gas reservoir large enough to sustain commercial development (Map 1). Developers describe the reservoir as being a sequence of fluvial sands, ranging from 500 to 800 feet thick, except where replaced/interrupted by volcanics (IOGCC 2013a). In the ML Investments #1-10 well, located in T. 8 N., R. 4 W., Section 10, the fluvial sand was found at 4,100 feet. Another sand layer is described at the 3,750 foot depth. The fluvial sands are porous and have consistent characteristics across the reservoir. They are overlain by 1,700 – 3,500 feet of lacustrine shale, which provides a regional topseal. Both sands are believed to be adequately drained by a well spacing of one well per 640 acres (IOGCC 2013a). The Western Idaho Basin is characterized primarily by conventional non-associated gas; however, conventional associated (with oil) and tight sand gasses may also be present, but shale-associated gas resources are not thought to be present (Johnson et. al. 2013). Conventional non-associated and associated gases typically can be extracted with smaller scale fracking (well-bore stimulation; Johnson et. al. 2013 pg. 8); however, tight sand and shale-associated gases likely would require fracking to extract.

Although BLM had numerous leases in the 1980's in the area, there are no current federal oil and gas leases in Payette County. In 2014, the Idaho Department of Lands (IDL) leased approximately 4,100 acres of State-owned minerals in Payette County. The remainder of the 20,288 acres of State-owned minerals in Payette County were leased between 2006 and 2013. The State currently has approximately 85,000 acres leased for oil and gas development statewide. There are no wells on federal mineral estates in Payette County; however, there is one producing well and 10 shut-in wells pending pipelines located on private lands (Table 11).

Table 11. Existing development activity on federal and State leases, Payette County, Idaho.

Well Type	Federal Estate	Private and State Leases
Drilling Well(s)	0	4
Producing Gas Well(s)	0	1
Shut-in Well(s) (pending pipeline)	0	10
Permitted, not Drilled Well(s)	0	2
Temporarily Abandoned Well(s)	0	1

3.13.2 Environmental Consequences – Minerals (Fluid)

Impacts to minerals are based on the RFDS created for this document (Table 2, Appendix 1).

3.13.2.1 General Discussion of Impacts

Issuing a lease provides the lessee with the exclusive right to explore for and develop oil and gas. Natural gas produced from federal mineral estate would enter the public markets. The production of oil and gas would result in the irreversible and irretrievable loss of these resources. Royalties and taxes would accrue to the federal and state treasuries from the lease parcel lands. There would be a reduction in the known amount of oil and gas resources. If the federal mineral estate is not leased, but is omitted by the Idaho Oil and Gas Conservation Commission (IOGCC), then they could be drained without compensation.

Stipulations applied to various areas with respect to occupancy, timing limitation, and control of surface use could affect oil and gas exploration and development, both on and off the federal parcel. Leases issued with major constraints (NSO stipulations) may decrease some lease values, increase operating costs, and require relocation of well sites, and modification of field development. Leases issued with moderate constraints (timing limitation and controlled surface use stipulations) may result in similar but reduced impacts, and delays in operations and uncertainty on the part of operators regarding restrictions.

3.13.2.2 Alternative A

The federal mineral estate could remain in place over the short and long terms if they were not leased. The two additional wells would occur in privately-owned mineral estate ≥ 0.5 miles from federal mineral estate. However, if the federal mineral estate were omitted by the IOGCC, then at least 493 acres of the federal mineral estate within 0.5 miles of existing wells (based on 1 well/640 acre spacing) could be drained.

Because of mineral ownership patterns, not leasing 6,349 acres of federal mineral estate could have moderate to major adverse effects on the ability to develop and produce State- and privately-owned fluid minerals. Lease values and operating costs could be adversely affected. Development of non-federal reserve minerals would not be adversely affected if the IOGCC omits the federal mineral estate.

3.13.2.3 Alternative B

The NSO and NSSO stipulations affecting 6,349 acres would cause minor to moderate decreased lease values and increased operating costs. Developing 22 wells on private lands would allow oil and gas production from the majority of federal mineral estate and State- and privately-owned minerals. Because of well spacing limitations, minerals from up to 1,920 acres of federal mineral estate would not be available because of NSO and NSSO stipulations. However, because of the interspersion of private lands in the proposed lease area, the amount of unavailable federal mineral estate would be expected to be much less.

3.13.2.4 Alternative C

Developing 25 wells would allow oil and gas production from almost all the federal mineral estate and State- and privately-owned minerals. Because of their proximity to federal mineral estate outside the lease area and current well spacing, some minerals at the periphery of the lease area might not be available for production. Applying lease stipulations would cause minor

decreased lease values and minor to moderate increased operating costs, primarily during the development phase. The special status plant species and freshwater aquatic habitat stipulations would affect approximately 190 acres of federal mineral estate (Maps 4 and 5). The big game winter range stipulation would affect 4,800 acres (Map 6). Fragile soils are associated with approximately 2,600 acres of federal mineral estate and floodplains would affect <1 acre (Maps 3 and 5). Impacts from other resource stipulations and lease notices cannot be determined at this time because surveys have not been conducted for the resources; however, migratory birds, raptors, burrowing mammals, and bats likely are associated with most of the federal mineral estate.

3.13.3 Mitigation

Applying the drainage stipulation in Alternative C would ensure that the lessee of a parcel adequately addresses the issue of uncompensated drainage.

3.13.4 Cumulative Impacts – Minerals (Fluid)

Cumulative impacts to fluid minerals are based on the RFDS created for this document (Table 2, Appendix 1) and the actions described below.

3.13.4.1 Scope of Analysis

The CIAA is the 15,644-acre Little Willow Creek proposed oil and gas lease area because only federal minerals in the lease area would be available. Well spacing guidance should prevent uncompensated drainage from the federal mineral estate outside the proposed lease area. The lease period of 10 years will be used for the temporal analysis limit because the federal mineral estate would be available for production during that time period, but not necessarily beyond.

3.13.4.2 Current Conditions and Effects of Past and Present Actions

In addition to the 6,349 acres of federal mineral estate, the CIAA includes 493 acres of State-owned minerals and 8,799 acres of private-owned minerals. The lease status of the State and private minerals is unknown. Six wells (three drilled and pending pipelines and three in the process of being drilled) occur in (three wells) or within 0.5 miles (three wells) of the CIAA. The wells are associated with privately-owned minerals; however, one well is within 0.15 miles of State-owned minerals.

3.13.4.3 Reasonably Foreseeable Future Actions

Two wells on privately-owned minerals could be drilled. Wells associated with State-owned minerals could be subject to stipulations for unstable soils, wildlife, threatened and endangered species, and floodplains (Appendix 2). Private lessors could also incorporate stipulations in their lease agreements; however, their scope is unknown.

3.13.4.4 Alternative A – Cumulative Impacts

Not leasing 6,349 acres of federal mineral estate could have minor (if the federal mineral estate is omitted) to moderate (if not omitted) adverse additive impacts to the value of unleased State- and privately-owned minerals. Stipulations associated with State-owned minerals could have minor adverse impacts on lease values and operating costs.

3.13.4.5 Alternative B – Cumulative Impacts

Leasing 6,349 acres of federal mineral estate with NSO and NSSO stipulations could have minor (if stipulations have a limited effect on accessibility) to moderate (if stipulations affect accessibility) adverse additive impacts to the value of unleased State- and privately-owned minerals. Stipulations associated with State-owned minerals would be as described in Alternative A (Section 3.13.4.4).

3.13.4.6 Alternative C – Cumulative Impacts

Leasing 6,349 acres of federal mineral estate with stipulations and lease notices would have minor adverse additive impacts to the value of unleased State- and privately-owned minerals. Stipulations associated with State-owned minerals would be as described in Alternative A (Section 3.13.4.4).

3.14 Social and Economic

3.14.1 Affected Environment – Social and Economic

Social and Environmental Justice

The 2010 Payette County population was 22,623, an increase of 10% from 2000. In comparison, the state population increased 21% between 2000 and 2010, Ada and Canyon counties increased 30.4% and 43.7% respectively. The 2010 Payette County population density was 55 persons/mi², compared to 18.8 for Idaho as a whole and 370 and 313 for Ada and Canyon counties respectively. The areas in the vicinity of the proposed lease area are home to farms, ranches, and dispersed residences.

As defined in Executive Order 12898, minority, low income populations, and disadvantaged groups are present in Payette County. Between 2008 and 2012, 19.2% of Payette County's population lived below the poverty line compared to 15.1% of Idaho's total population (Payette County QuickFacts, USCB 2014). The County is not very ethnically or racially diverse. In 2010, 85% of residents identified themselves as being non-Hispanic or Latino ethnicity and 15% of residents reported having Hispanic ancestry (US Census Bureau 2010). Non-white races including African American, Asian, American Indian, Pacific Islander, and others accounted for 11% of the population. In 2010, American Indians accounted for 1.1% of Payette County's population compared to 1.4% for the state as a whole. Tribes in Idaho and elsewhere have an interest in lands in Payette County; however, BLM is unaware of potential interest involving the proposed lease area.

Economics

In 2011, Payette County supported 9,606 jobs and had a 9.1% unemployment rate (Table 12). Non-services related industries (e.g., farm, construction, and manufacturing) accounted for 2,868 jobs, while service related industries (e.g., wholesale, retail, transportation, finance, real estate, and health care) accounted for 5,330 jobs and government accounted for 1,146 jobs (U.S. Department of Commerce 2011). In 2012, labor earnings of \$325 million included \$100 million in non-services related, \$153 million in services related, and \$47 million in government related earnings. The 2011 per capita income was \$29,475. Total personal income (TPI) in 2011 was

estimated to be \$667 million including a net residential inflow of \$105 million (earnings gained from outside the county – earnings leaving the county). Total personal income includes labor and non-labor income, including money earned on investments (interest, dividends, and rents) and transfer payments relating to age (Medicare and Social Security payments) or poverty (Medicaid or welfare assistance). Idaho had 147 people employed in oil and gas extraction activities statewide in 2011 (IPAA 2012).

Table 12. Employment (2011) and personal income (2012) by industry, Payette County, Idaho.

Industry	Employment (jobs)	Personal Income (Thousands of 2012 dollars)	Average Income/Job (Thousands of 2012 dollars)
Farm	974	\$28,255	\$29
Forestry & Related Activities	na	na	na
Mining (incl. fossil fuels) ¹	na	na	na
Construction ¹	780	\$25,285	\$32.4
Manufacturing	1,114	\$46,321	\$41.6
Utilities	95	\$10,480	\$110.3
Wholesale Trade ¹	278	\$9,247	\$33.3
Retail Trade ¹	734	\$13,380	\$18.2
Transportation & Warehousing ¹	341	\$13,446	\$39.4
Information	111	\$6,604	\$59.5
Finance & Insurance ¹	381	\$9,798	\$25.7
Real Estate & Rental & Leasing ¹	426	\$3,543	\$8.3
Professional & Tech. Services ¹	313	\$10,763	\$34.4
Management of Companies ¹	90	\$8,503	\$94.5
Admin. & Waste Services ¹	526	\$9,587	\$18.2
Educational Services	90	\$868	\$9.6
Health Care & Social Assistance ¹	844	\$35,832	\$42.5
Arts, Entertainment, and Rec	94	\$545	\$5.8
Accommodation & Food Services ¹	294	\$3,843	\$13.1
Other Services ¹	713	\$16,977	\$23.8
Government ¹	1,146	\$47,312	\$41.3
Total	9,606	\$325,048	\$33.8

¹ Industries that typically add jobs to support oil and gas leasing, exploration, and production activities.

Oil and Gas Leasing and Production

Local economic effects of leasing federal minerals for oil and gas exploration, development, and production are influenced by the number of acres leased, the number of wells drilled, and the estimated levels of production. These activities influence local employment, income, and public revenues (indicators of economic impacts). There are no federal-administered leases in the area; however, in 2014, the IDL leased 4,006 acres of State owned lands and minerals in Payette County.

Leasing - Federal oil and gas leases generate a one-time lease bid as well as annual rents. Parcels containing federal minerals, which have been approved for leasing, are auctioned off periodically to interested parties starting at a minimum bid of \$2.00 per acre. Many parcels leased at auction generate bonus bids in excess of the minimum bid. In 2014, bonus bids ranged from \$50.24/acre (October) to \$79.68/acre (January) for State leases; however, because no leases have been offered, figures for federal minerals are not available. Once federal minerals are leased, leases are subject to annual rent or royalty payments. Rent on leased minerals is \$1.50 per acre per year for the first five years and \$2.00 per acre per year thereafter. Typically, oil and gas leases expire after 10 years unless drilling activity on these parcels results in one or more producing wells.

Production – Idaho currently has one producing well on private land and none associated with federal mineral estate (IPAA 2012, IDL 2014). Of 18 Payette County gas wells currently permitted by IDL, one is in production, 10 have been drilled and are shut pending a pipeline (Table 11). Once production begins, federally leased minerals are considered to be held by production and lease holders are required to pay royalties on production instead of annual rent. The BLM also considers mineral leases to be held by production if they have been incorporated into fields or units working cooperatively to increase extraction capabilities.

Federal oil and gas production is subject to production taxes or royalties. On public domain lands, these federal oil and gas royalties generally equal 12.5% of the value of production (43 CFR 3103.3.1), of which 50% would be allocated to the State and 50% would be allocated to the U.S. Treasury. In Idaho, 90% of federal mineral royalty revenues that the state receives are distributed to the Public School Income Fund and 10% distributed to the general fund of the counties where the revenue was generated. For State leases, a 12.5% production royalty is distributed to the permanent fund of the appropriate beneficiary, other State agencies, and the General Fund. The 2.5% production tax goes to the producing county (11.2% of tax revenue), cities within the producing county (11.2%), public schools (11.2%), local economic development (6.4%), and an oil and gas conservation fund (60%).

Local Economic Contribution - Oil and gas development has the potential to stimulate economic activity in a number of sectors throughout the region. Exploration, development, and production activities create a multiplier effect in the local economy as money spent in the oil and gas related industries is spent and re-spent in other industries (Table 12).

3.14.2 Environmental Consequences – Social and Economic

Impacts to the social and economic environment are based on the RFDS created for this document (Table 2, Appendix 1).

3.14.2.1 General Discussion of Impacts

Social and Environmental Justice

Development of a lease may generate impacts to people living near or using the area in the vicinity of the lease. Oil and gas exploration, drilling, or production could create an inconvenience to these people due to increased traffic and traffic delays, noise, and visual impacts. This could be especially noticeable in areas where oil and gas development has been

minimal. The amount of inconvenience would depend on the activity affected, traffic patterns within the area, noise levels, length of time, and season these activities occurred, etc. Creation of new access roads into an area could allow increased public access and exposure of private property to vandalism. For split estate leases, surface owner agreements, standard lease stipulations, and BMPs could address many of the concerns of private surface owners. Production and development activities could disproportionately affect disadvantaged groups where the activities are specifically targeted to their communities or properties to the benefit or avoidance of non-disadvantaged groups. They could also provide job opportunities for those groups.

Economics

Local and/or out-of-state workers could be hired or contracted to meet the direct and indirect needs of development and production. Individual income for workers typically associated with development and production activities would vary from \$8,300 to \$94,500 annually (Table 12). Mining-related jobs would likely pay above the median income (\$32,400/year). Total new jobs created could be relatively low because some work would be short-term in nature. For each million dollars in gas production, 2.4 jobs could be created in the county of production (Weber 2012). Employees may shift to higher paying energy-related jobs creating a labor shortage for local employers. Sudden influxes of workers could reduce affordable housing availability. An influx of workers and equipment without commensurate financial support could adversely affect public and private sector infrastructure (schools, hospitals, law enforcement, fire protection, and other community needs), especially in rural communities. Tax, royalty, spending, and income revenues associated with leasing, development, and production would benefit local, county, State, and national economies. Stipulations that affect access to mineral resources could reduce economic return for lessors and lessees. Activities that increase access to mineral resources could benefit other mineral rights holders. Activities that adversely affect health, safety, or the environment could cause short- or long-term decreases in personal income and property values. Wildlife depredation on agricultural fields could adversely affect productivity of some crops (e.g., winter wheat, alfalfa).

Disclosure of the direct, indirect, and cumulative effects of GHG emissions provides information on the potential economic effects of climate change including effects that could be termed the “social cost of carbon” (SCC). The EPA and other federal agencies developed a method for estimating the SCC and a range of estimated values (EPA 2014). The SCC estimates damages associated with climate change impacts to net agricultural productivity, human health, property damage, and ecosystems. Using a 3% average discount rate and year 2020 values, the incremental SCC is estimated to be \$51 per ton of annual CO₂eq increase.

3.14.2.2 Alternative A

Social and Environmental Justice

Not leasing the federal mineral estate in the project area would limit the development potential of the project area to only two wells, both located on private lands. Developing two wells and associated infrastructure would have minor short-term impacts from increased traffic and noise and long-term visual, public access, and vandalism impacts. Limited increases in access and

worker influx would occur. There are disadvantaged groups in Payette County, but they do not appear to be disproportionately associated with the two wells or the proposed lease area.

Economics

By not leasing, federal, state, or local revenues would not be generated from leasing, rents, or royalties from federal mineral estate. If BLM does not lease the federal minerals, it is likely that the IOGCC would allow the federal mineral estate to be omitted from the drilling unit. Moderate (if 493 acres associated with existing wells are omitted) to major (if up to 6,349 acres throughout the lease area are omitted) resource and revenue losses would occur if the IOGCC omitted the federal mineral estate and productive wells are drilled on private lands in the same unit. Development and production of two wells would cause minor employment and income increases. Negligible to minor impacts to labor and housing availability and infrastructure would occur over the short term. Adjacent mineral rights holders would experience minor beneficial (omission allowed) or moderate adverse (omission not granted) financial impacts. Adverse water quality and availability (Section 3.5.2.2), safety, and environmental impacts would primarily affect individual landowners in the immediate vicinity of the wells. Negligible wildlife depredation losses could occur.

Based on the GHG emission estimate (Table 6), the annual SCC associated with two wells would be \$295,137 (in 2011 dollars). Estimated SCC is not directly comparable to economic contributions reported above, which recognize certain economic contributions to the local area and governmental agencies, but do not include all contributions to private entities at the regional and national scale. Direct comparison of SCC to the economic contributions reported above is also not appropriate because costs associated with climate change are borne by many different entities.

3.14.2.3 Alternative B

Social and Environmental Justice

Developing 22 wells and associated infrastructure would have moderate to major short-term increased traffic and noise impacts and long-term visual impacts. Minor (access controlled by private landowners) to major (access not controlled by private landowners) access and vandalism impacts could occur over the long term. A moderate worker influx could adversely affect traditional lifestyles. Disadvantaged groups in Payette County would not be directly affected by the wells, but access to affordable housing and social services in nearby communities could be reduced during the short term.

Economics

Federal, state, or local revenues would be generated from leasing and rents (\$9,528 to \$12,704 annually) during the 10-year lease period. The NSO and NSSO stipulations could reduce the lease value and bonus bid amounts. Developing and maintaining 22 wells would have minor to moderate short-term and negligible long-term job increases. Royalty income would depend on how productive the wells are and cannot be estimated at this time. Minor to moderate impacts to labor and housing availability and infrastructure would occur over the short term. Adjacent mineral rights holders would experience moderate financial benefits where access to their minerals improved. Adverse water quality and availability (Section 3.5.2.3), safety, and

environmental impacts could have negligible (wells remain intact and don't affect ground water) to major (surface and ground water adversely affected by multiple wells) to the adjacent landowners and downstream communities. Minor to moderate wildlife depredation losses could occur. Based on the GHG emission estimate (Table 6), the annual SCC associated with 22 wells would be \$3,246,711 (in 2011 dollars).

3.14.2.4 Alternative C

Social and Environmental Justice

The impacts of developing 25 wells and associated infrastructure would be as described in Alternative B (Section 3.14.2.3).

Economics

Leasing 6,349 acres and associated development and production would have similar revenue, job, labor and housing availability, infrastructure, and adjacent mineral rights holder impacts as described in Alternative B (Section 3.14.2.3). The impact of CSU stipulations on lease value would be less than Alternative B and royalty income could be greater. Adverse water quality and availability (Section 3.5.2.4), safety, and environmental impacts would be similar to Alternative B; however, the freshwater aquatic habitat CSU stipulation could provide minor to moderate surface water protection. Minor wildlife depredation losses could occur. Based on the GHG emission estimate (Table 6), the annual SCC associated with 25 wells would be \$3,689,442 (in 2011 dollars).

3.14.3 Mitigation

Measures that limit or control dust, noise, odors and protect visual impacts and water quality resources would help reduce social and economic impacts (Dahl et. al. 2010).

3.14.4 Cumulative Impacts – Social and Economic

Cumulative impacts to the social and economic environment are based on the RFDS created for this document (Table 2, Appendix 1), RFDS for the Willow and Hamilton fields, and the activities identified below.

3.14.4.1 Scope of Analysis

Payette County will serve as the CIAA. Although social and economic costs and benefits could occur at regional, state, national, and international levels, the majority would occur at the county level. The lease period of 10 years will be used for the temporal analysis limit because the federal mineral estate would be available for production during that time period, but not necessarily beyond.

3.14.4.2 Current Conditions and Effects of Past and Present Actions

Current Payette County social and economic conditions are described in Section 3.14.1. All State-owned minerals (Section 3.13.1) and an unknown acreage of privately-owned minerals have been leased in recent years. The State leases will expire between 2016 (14,181 acres) and 2024. The existing 17 oil and gas wells have been developed over several years, although the

majority of work occurred since 2011. Exploration work is ongoing in the County. The effect of these activities on social and economic conditions, beyond State lease rental returns, is unknown.

3.14.4.3 Reasonably Foreseeable Future Actions

Oil and Gas Lease Development and Production – Development of wells and associated infrastructure would occur on private and State leases in the Willow and Hamilton (one new well proposed October 2014) fields. Current development is approximately two to four wells annually.

3.14.4.4 Alternative A – Cumulative Impacts

Social and Environmental Justice

Development of two wells and associated infrastructure would have negligible additive traffic, noise, visual, access, vandalism, and worker influx impacts. Development of up to 53 wells in the Hamilton and Willow fields would have minor impacts. The county's population base is large enough that changes associated with oil and gas development would be relatively unnoticeable.

Economics

Not leasing federal mineral estate would have negligible additive adverse revenue impacts. Development of two wells and associated infrastructure would have negligible additive employment, income, labor and housing availability, infrastructure, water quality and availability, and SCC impacts. Development of up to 53 wells in the Hamilton and Willow fields would have minor revenue, employment, income, labor and housing availability, infrastructure, safety, and environmental impacts. Development in the Hamilton and Willow fields could cause minor (water availability affected by increased use) to moderate (water quality adversely affected by persistent pollutants) water quality and availability and SCC (\$7,660,302) impacts. The county's economic and employment base is large enough that changes associated with oil and gas development would be relatively unnoticeable.

3.14.4.5 Alternatives B and C – Cumulative Impacts

Social and Environmental Justice

Leasing federal mineral estate and the subsequent development of 22-25 wells and associated infrastructure would have minor additive traffic, noise, visual, access, vandalism, and worker influx impacts. Impacts from other oil and gas development would be as described in Alternative A (Section 3.14.4.4).

Economics

Leasing federal mineral estate and the subsequent development of 22-25 wells and associated infrastructure would have minor additive employment, income, labor and housing availability, and infrastructure impacts and minor to moderate additive water quality and availability and SCC impacts. Impacts from other oil and gas development would be as described in Alternative A (Section 3.14.4.4).

4.0 Consultation and Coordination

4.1 List of Preparers

Name	Position
Jonathan Beck	Planning and Environmental Coordinator, ID State Office and Boise District
Aimee Betts	Associate District Manager, Boise District
M.J. Byrne	Public Affairs, Boise District
Tate Fischer	Field Office Manager, Four Rivers
Sarah Garcia	Rangeland Management Specialist, Four Rivers
Lara Hannon	Natural Resource Specialist/Acting NEPA Specialist, Boise District
Valerie Lenhartzen	Geologist, Four Rivers
Matthew McCoy	Assistant Field Office Manager, Four Rivers
David Murphy	Branch Chief, Realty, ID State Office
Karen Porter	Geologist, ID State Office
Larry Ridenhour	Outdoor Recreation Planner, Four Rivers
Dean Shaw	Archaeologist, Four Rivers
Mark Steiger	Botanist, Four Rivers
Allen Tarter	Natural Resource Specialist (Riparian), Four Rivers

4.2 List of Agencies, Organizations, and Individuals Consulted

Affected Landowners and Permittees (84 individual or companies within 1 mile of proposed lease area)

Allen and Kirmse, Ltd

Alta Mesa Service, Inc., c/o F. David Murrell

Burns Paiute Tribe, Tribal Chairman

Canyon County Commissioners

Confederate Tribes of the Umatilla, Tribal Chairman

Congressman Raul Labrador

Energy West Corp.

Gem County Commissioners

Grazing Board Resource Area Representatives, Phil Soulen

Grazing Board Resource Area Representatives, Stan Boyd

Grazing Board Resource Area Representatives, Weldon Branch

Idaho Citizens Against Resource Extraction

Idaho Conservation League, John Robinson

Idaho Department of Agriculture

Idaho Department of Fish & Game c/o Rick Ward

Idaho Department of Lands c/o Grazing Program Manager

Idaho Governor, CL "Butch" Otter

Idaho Lieutenant Governor Brad Little

Idaho Office of Energy Resources, c/o John Chatburn

Little Willow Creek Protective Oil and Gas Lease

Final Environmental Assessment

DOI-BLM-ID-B010-2014-0036-EA

Larry Craig
Moffitt Thomas and Associates
Nez Perce Tribes, Tribal Chairman
SBS Associates, LLC
Senator Jim Risch
Senator Mike Crapo
Shoshone-Bannock Tribe, c/o Nathan Small
Shoshone-Paiute Tribe, c/o Ted Howard
Trendwell Energy Corp.
US Fish and Wildlife Service
Washington County Commissioners
Weiser-Brown Oil Co, c/o Richard Brown
Western Watersheds Project
WildLands Defense, Katie Fite

Native American Consultation

BLM is required to consult with Native American tribes to “help assure (1) that federally recognized tribal governments and Native American individuals, whose traditional uses of public land might be affected by a proposed action, will have sufficient opportunity to contribute to the decision, and (2) that the decision maker will give tribal concerns proper consideration” (U.S. Department of the Interior, *BLM Manual Handbook H-8120-1*). Tribal coordination and consultation responsibilities are implemented under laws and executive orders that are specific to cultural resources which are referred to as “cultural resource authorities,” and under regulations that are not specific which are termed “general authorities.” Cultural resource authorities include: the *National Historic Preservation Act of 1966*, as amended (NHPA); the *Archaeological Resources Protection Act of 1979*; and the *Native American Graves Protection and Repatriation Act of 1990*, as amended. General authorities include: the *American Indian Religious Freedom Act of 1979*; the NEPA; the FLPMA; and *Executive Order 13007-Indian Sacred Sites*. The proposed action is in compliance with the aforementioned authorities.

Southwest Idaho is the homeland of two culturally and linguistically related tribes: the Northern Shoshone and the Northern Paiute. In the latter half of the 19th century, a reservation was established at Duck Valley on the Nevada/Idaho border west of the Bruneau River. Today, the Shoshone-Paiute Tribes residing on the Duck Valley Reservation actively practice their culture and retain aboriginal rights and/or interests in this area. The Shoshone-Paiute Tribes assert aboriginal rights to their traditional homelands as their treaties with the United States, the Boise Valley Treaty of 1864 and the Bruneau Valley Treaty of 1866, which would have extinguished aboriginal title to the lands now federally administered, were never ratified.

Other tribes that have ties to southwest Idaho include the Bannock Tribe and the Nez Perce Tribe. Southeast Idaho is the homeland of the Northern Shoshone Tribe and the Bannock Tribe. In 1867 a reservation was established at Fort Hall in southeastern Idaho. The Fort Bridger Treaty of 1868 applies to BLM’s relationship with the Shoshone-Bannock Tribes. The northern part of the BLM’s Boise District was also inhabited by the Nez Perce Tribe. The Nez Perce signed treaties in 1855, 1863 and 1868. BLM considers off-reservation treaty-reserved fishing,

hunting, gathering, and similar rights of access and resource use on the public lands for all tribes that may be affected by a proposed action.

The BLM initiated consultation with the Shoshone-Paiute Tribes during the June 19, 2014 Wings and Roots Program, Native American Campfire meeting. At that time, the Tribes were provided an information “early alert” with updated information from the June 12, 2014, field trip. The Shoshone-Paiute Tribes did not respond to a July 3, 2014 scoping letter, but will be consulted once again at the December 2014 Wings and Roots Program, Native American Campfire meeting.

4.3 Public Participation

The BLM received public scoping comments from the following individuals and entities (see Section 8.0 Comment Response for comments specific to the draft EA):

Alta Mesa Services, Inc.
Idaho Concerned Residents for the Environment (ICARE)
Idaho Office of Energy Resources
Idaho Petroleum Council
Idaho Residents Against Gas Extraction (IRAGE)
Jason Williams
JoAnn Higby
Lyndsey Winters Juel
Marilyn Richardson
Terry Paulus
William Fowkes and Alice Whitford
Western Watersheds Project (WWP)

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6.0 Appendices

6.1 Appendix 1. Reasonably foreseeable development scenario for the proposed Little Willow Creek oil and gas lease area, Payette County, Idaho.

REASONABLY FORESEEABLE DEVELOPMENT SCENARIO
FOR
PROTECTIVE OIL AND GAS LEASING
IN PARTS OF
TOWNSHIP 8 NORTH, RANGE 4 WEST
TOWNSHIP 9 NORTH, RANGE 4 WEST, AND
TOWNSHIP 9 NORTH, RANGE 3 WEST
BOISE MERIDIAN
FOUR RIVERS FIELD OFFICE
IDAHO

Prepared by: _____ Date: _____

Karen Porter
BLM Idaho State Office Geologist

SUMMARY

The BLM's Four Rivers Field Office is currently analyzing the environmental effects of offering 6474.62 acres of federal mineral estate for competitive oil and gas leasing. This RFDS is being written in support of that analysis, to inform the public and the preparers of the environmental assessment of the disturbance that could occur as a result of leasing the lands, so that the environmental impacts can be determined and mitigation measures, in the form of lease stipulations, can be developed to minimize those impacts. The BLM plans to offer these lands in a lease sale in early 2015, in order to protect the federal mineral estate from potential drainage caused by the development of a natural gas field that is presently occurring on private lands, referred to by the developer as the Willow Field.

According to an April 16, 2013 order by the Idaho Oil and Gas Conservation Commission, well spacing in the area is one well per government section, or 640 acres. In the northern part of the field, lands with reserved federal mineral estate (also called split estate) are intermingled with some of the private lands, causing conflicts for the developer. Idaho BLM has been deferring leasing in the Four Rivers FO while the current land use plan, the CRMP, is being revised. The CRMP/EIS was completed in 1987, and, while it identified lands closed to leasing and identified some areas as No Surface Occupancy, the analysis does not meet current BLM standards for oil and gas leasing. One major component that is missing is an analysis based on a Reasonably Foreseeable Development Scenario, or RFDS. Therefore, this RFDS describes the likely disturbance that could occur if BLM were to select any of the alternatives being proposed.

This Reasonably Foreseeable Development Scenario (RFDS) indicates that the following impacts could occur, by alternative:

Alternative A (No Action) - If BLM does not lease in the project area, development drilling could occur in only 2 sections- T. 8 N., R. 4 W., section 2, and T. 9 N., R. 4 W., section 36. The lands in these sections are private and do not contain any federal mineral estate. Technically only two wells could be drilled in the project area. This would result in approximately 10 acres of disturbance.

Alternative B (Lease with NSO/NSSO) - Offering leases with NSO/NSSO would allow those sections that have lands with federal mineral estate to be drilled, however the drilling could not occur on the federal mineral estate. The only federal action would be to administer the leases and collect royalties. As there is only one section that has 100% federal minerals (T 9 N., R. 4 W., section 26) and there are 25 sections within the project boundary, technically Alt B could result in up to 24 wells. However, in looking at the topography of each section, it is noted that there are several sections where the private land is either inaccessible or is too steep to be suitable as a drill site. Two sections- T. 9 N., R. 4 W., section 13, and T. 9 N., R. 3 W., section 17- do not have favorable private land conditions for drilling. Therefore, if Alt B were selected, it is estimated that 22 wells would be drilled in the project area, resulting in 77 acres of disturbance.

Alts C (Lease with Cascade RMP stipulations and additional lease notices) - Generally all

federal minerals would be available for development, resulting in the drilling of 25 wells (one per section), and 88 acres of disturbance.

It is anticipated that one geophysical exploration program would occur and that it would likely be conducted along existing roads or trails or by overland travel, thereby causing minor impacts to surface resources.

INTRODUCTION

This report describes the anticipated level of oil and gas exploration and development activity associated with issuing oil and gas leases in the project area. This projection is necessary so that the impacts to other natural resources can be analyzed in an environmental assessment, and to determine what if any stipulations, in addition to those on the standard lease form and those required by BLM policy, may be necessary to attach to the leases in order to mitigate those impacts.

ASSUMPTIONS AND DISCUSSION

- It is assumed that one well would be drilled per government section of approximately 640 acres. This is based on the state of Idaho's well spacing order.
- If a well is to be located on a federal lease, the lessee will be required to submit a drilling permit (APD) to BLM for approval prior to commencing operations. Site-specific NEPA would then be conducted, and additional site-specific requirements, termed Conditions of Approval, may be attached to the APD. If the well is to be located on fee lands, the lessee would seek approval for a drilling permit from the Idaho Department of Lands.
- If drilling is proposed on split estate lands, the lessee will be required to contact the surface owner and attempt to reach an agreement concerning surface access prior to submitting the APD. In accordance with BLM's Onshore Order Number One, upon submitting an APD, the lessee or its operator must certify to the BLM that: (1) It made a good faith effort to notify the private surface owner before entry; and (2) A Surface Access Agreement with the surface owner has been reached, or that a good faith effort to reach an agreement failed. The Surface Access Agreement may include terms or conditions of use, be a waiver, or an agreement for compensation. BLM is not a party to the surface agreement, however if no agreement is reached with the surface owner, the operator is required to submit an adequate bond (minimum of \$1000) to the BLM for the benefit of the surface owner, in an amount sufficient to compensate for any loss of crops or damage to tangible improvements. This is a separate and distinct bond from the reclamation bond required under 43 CFR 3104.
- Based on the recent drilling that has occurred in the Willow Field, it is assumed that any well drilled would be a vertical hole, and that it would not require hydraulic fracturing. It is also assumed that the well would be a natural gas well.

- If the well is productive, it is assumed that it would be incorporated into the Willow Field unit development. If dry, the well would be plugged and abandoned, and the site would be reclaimed.
- Oil and gas leases are issued for an initial term of 10 years, subject to extension if there is drilling occurring or if there is a producing well on the lease.

ANTICIPATED SURFACE DISTURBANCE DUE TO OIL AND GAS ACTIVITIES

The following phases of oil and gas exploration/development are typical in searching for and developing an oil and gas resource:

1. Geophysical Exploration
2. Drilling Phase
3. Field Development and Production
4. Plugging and Abandonment

These phases are discussed in detail below.

Phase One: Geophysical Exploration

While a geophysical exploration program may have already been conducted, for the sake of this report it is anticipated that one geophysical exploration program may be conducted during the 10-year initial term of the leases. Geophysical techniques are often implemented to identify subsurface geologic structures and determine drilling targets. The BLM reviews and approves geophysical operations on a case by case basis, and a lease is not necessary for such work. Gravity, magnetics, and seismic reflection are the most common techniques used. Both gravity and magnetic surveys cause very little disturbance as the instruments used are small and easily transportable in light vehicles or OHVs. These surveys can cover large areas and take only weeks to conduct. It is preferable to use existing roads, yet some overland travel is sometimes necessary. In addition, both gravity and magnetic surveys can be completed from aircraft, virtually eliminating surface disturbance.

Seismic reflection surveys- either 2D or 3D- are the most commonly used geophysical tool. They require a seismic energy source and an array of receptors that are laid down in rows on the ground surface. Shock waves are created by vibrating or thumping the ground. Reflected seismic waves are recorded by a series of surface equipment along a 3- to 5-mile line. The general principle of seismic reflection is to send elastic waves (using an energy source such as dynamite explosion or Vibroseis) into the Earth, where each layer within the Earth reflects a portion of the wave's energy back and allows the rest to refract through. These reflected energy waves are recorded over a predetermined time period by receivers that detect the motion of the ground in which they are placed. On land, the typical receiver used is a small, portable instrument known as a geophone, which converts ground motion into an analogue electrical

signal. In preparation for gathering the seismic data, the survey crew establishes a grid, with source lines running one direction and receiver lines running a different direction. The source lines mark the points where either explosives or vibroseis vehicles will be placed. The receiver lines mark points where geophones (small devices inserted into the ground that pick up reflected vibrations) are placed to take readings when either a small explosion is set off or, more commonly, the vibroseis vehicles are used. Either method is used to send vibrations underground that are reflected back to the surface where readings are taken by geophones on the receiver lines and transferred to a data recorder vehicle. A crew of 10 to 15 people with five to seven vehicles is used, and several square miles can be surveyed in a single day. The geophones are then retrieved from the ground, and moved to the next survey area.

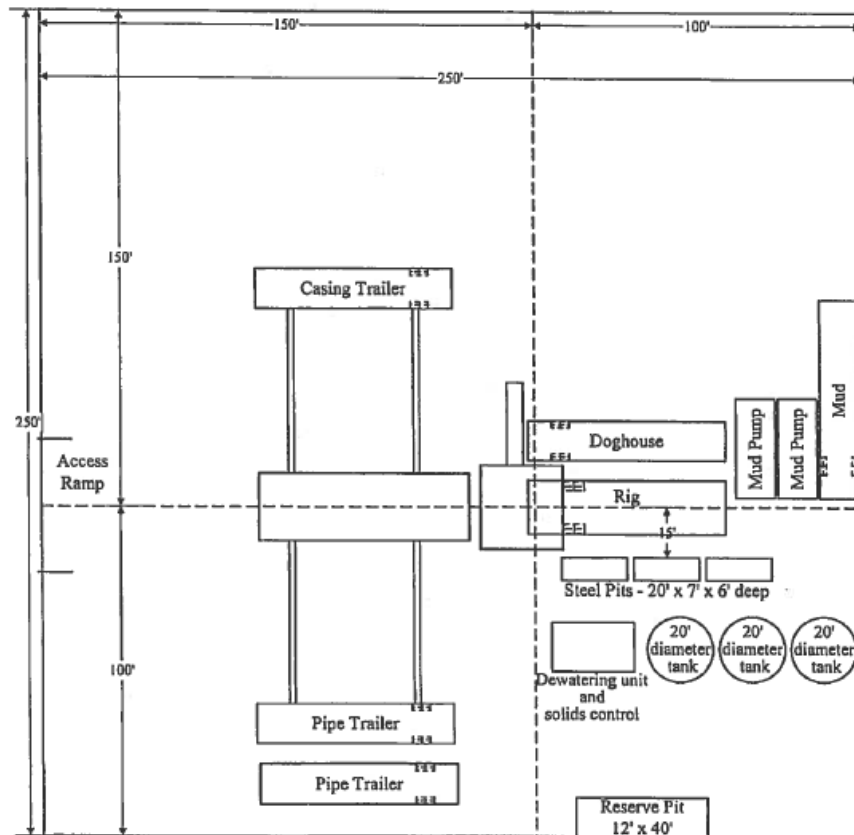
Phase Two: Drilling Phase

Given Idaho's well spacing requirements, it is assumed that a single well would be drilled in each section. If the proposed well is located on lands with federal minerals (i.e. on a federal lease), the lessee is required to submit an APD to BLM. If the proposed well is located on lands with private or state minerals, the lessee would submit a drilling permit application to the Idaho Department of Lands. Drilling on federal mineral estate would be analyzed by BLM in a site-specific NEPA document, and would involve coordination with the surface owner. Conditions of Approval, specific to the proposed activity and site, would be developed and attached to the drilling permit. These conditions, as well as the lease contract itself and any additional stipulations, would need to be complied with. A reclamation bond is required, and if necessary, a surface owner bond would be held by BLM on the surface owner's behalf.

Vehicle access to each drill pad would be required, to transport the drill rig, personnel, and other heavy equipment to the drill site. Existing roads may be used, however may require upgrading. Most of the individual parcels can be accessed off of the Little Willow Creek road, which is paved. Two-track and gravel roads that branch off of Little Willow Creek may require upgrading. Typically, roads are constructed with a 20-foot wide graveled running surface with adjacent ditches and berms, for a total disturbance width of about 40 feet. It may be necessary to haul in gravel to obtain a good road base, as well as a base for the well pad. In the area of the subject parcels, there are several good gravel roads that provide access to some part of the section that would be an appropriate drilling site. It is unlikely that the lessee would need access to the top of the bluffs on which many of the parcels lie. Given the existing road density in the area, it is assumed that an average of 1/4 of a mile of new road construction would be required to access the drill sites. Surface disturbance from the construction of 1/4 mile of road equals approximately one acre.

A drill pad is required to accommodate the rig and equipment. Previous drill pads in the Willow Field have been approximately 1.5 acres in size, however this report assumes a larger pad of 2.5 acres (300' x 350'). Topsoil and existing vegetation is scraped from the well pad site and stored on site for reclamation. The drill pad must be level, possibly requiring some cut-and-fill of the site. In addition to the drill rig, the well pad may house a reserve pit for storage or disposal of water, drill mud, and cuttings; several mud pits and pumps, drill pipe racks, a fuel tank, a water tank, a generator and several compressors, equipment storage, and several trailers for temporary

lab and office quarters. To date, reserve pits associated with developing the Willow Field have all been lined with a 12-mil synthetic liner. Below is a schematic diagram of an actual well pad (from Bridge Energy Resources' drilling permit application to IDL):



Getting the rig and ancillary equipment to the site may require 15 to 20 trips by full-sized tractor-trailers, with a similar amount for de-mobilizing the rig. There would be 10 to 40 daily trips for commuting and hauling in equipment. Drilling operations would likely occur 24 hours a day and seven days a week. It takes approximately one month to drill one well. A drilling operation generally has from 10 to 15 people on-site at all times, with more people coming and going periodically with equipment and supplies.

Well drilling also requires water. As much water as possible is recycled on site, yet about 5,000 to 15,000 gallons of water may be needed each day depending on well conditions. Initially, water would need to be provided, either by wells or trucked in, to meet demands. Many oil or gas wells encounter water at depth when drilling for oil and/or gas, as it may be part of the oil and gas reservoir, and can be utilized when production is ongoing.

Production wells drilled in the Willow Field to-date have been 24 inches in diameter at the surface, gradually narrowing (telescoping) to 8¾ inches at the bottom of the well. In order to

drill these deep, large-diameter holes, a large drilling rig is utilized. The top of the drill rig derrick could be as much as 155 feet above the ground surface, and the rig floor could be at least 25 feet above the ground surface. These rigs are typically equipped with diesel engines, fuel and drilling mud storage tanks, mud pumps, and other ancillary equipment. Once drilling commences, drilling fluid or mud is continuously circulated down the drill pipe and back to the surface equipment. The purpose of the drilling mud is to balance underground hydrostatic pressure, cool the drill bit, and flush out rock cuttings.

The risk of an uncontrolled flow from the reservoir to the surface (occasionally caused by encountering a pressurized thermal pocket) is greatly reduced by using a blowout preventer—a series of hydraulically-actuated steel rams that can close quickly around the drill string or casing to seal off a well. The BOP is pressure-tested after installation to ensure proper operation. Steel casing is run into completed sections of the borehole and cemented into place. The casing provides structural support to maintain the integrity of the borehole and isolates underground formations.

Exploration holes drilled to-date in the Willow Field have ranged in depth from 2500 to 6900 feet. At the conclusion of well testing, if paying quantities of oil and gas are not discovered, the operator is required to plug and abandon the well according to State standards. Cement plugs are placed above and below water-bearing units with drilling mud placed in the space between plugs. When abandonment is complete, the site is reclaimed, which includes pad and road recontouring, topsoil replacement, and seeding with approved mixtures. Erosion control measures would be incorporated into the reclamation design as needed.

The drilling site could be active for approximately one year, from the start of drill pad and access road construction; through drilling and well testing; to completion of plugging the hole and reclamation.

Phase Three: Field Development and Production

Where oil and gas flow to the surface naturally, control valves and collection pipes are attached to the well head. Otherwise a pump may be installed. Oil is typically produced along with water and gas. Once the raw hydrocarbon reaches the surface, it would be routed through a pipeline to a central production facility, which gathers and separates the produced fluids (oil, gas and water). A production facility is currently being constructed on private lands on the east side of the town of New Plymouth, and dehydration plant has been constructed on Highway 30, immediately north of Interstate 84. The production facility processes the hydrocarbon fluids and separates oil, gas and water. The oil must usually be free of dissolved gas before export. Similarly, the gas must be stabilized and free of liquids and unwanted components such as hydrogen sulphide and carbon dioxide. Any water produced would be treated at these facilities before disposal. Produced water at the well site is disposed of either through surface discharge, evaporation ponds or re-injection into the producing formation.

The producing life span of an oil or gas field varies depending on field characteristics. A field may produce for a few years to many decades. Commodity price, recovery technique, and the

political environment also affect the life of a field. Abandonment of wells may begin as soon as they are depleted or wells may be rested for a period of time or drilled to a different horizon, and put back into production.

Phase Four: Abandonment

If paying quantities of oil and gas are not discovered, or at the end of the producing life span of a producing well or field, the operator is required to plug and abandon the well according to Federal and State standards and reclaim the disturbed areas. To plug a well, cement plugs are placed above and below water-bearing units with drilling mud placed in the space between plugs. When well abandonment is complete, equipment and surface facilities are removed, and the site is reclaimed. In a producing field, underground pipelines are often plugged and left in place in order to avoid re-disturbing these areas. Site reclamation includes pad and road obliteration and recontouring, topsoil replacement, and seeding with approved mixtures. Erosion control measures would be incorporated into the reclamation design as needed.

CONCLUSION

Surface disturbance associated with the anticipated leasing of the federal mineral estate in the project area would be approximately 5 acres per well. One well can be drilled per section according to the State of Idaho's well spacing order. Therefore, depending on which alternative is selected, between 10 acres and 125 acres could be disturbed. Pad and access road construction, drilling and well testing, and reclamation would take an estimated 4-6 months, depending on well depth and drilling conditions encountered. It is reasonably likely that well testing would be favorable for production, in which case a pipeline would likely be installed to transport the hydrocarbons to a central production facility located off-lease, located on private land several miles to the south. It is anticipated that one geophysical survey program would be completed during the life of the lease. This disturbance would be temporary, on the order of weeks, and would result in minor to negligible surface impacts.

This RFDS meets the requirements of BLM's Manual Section 1624-2 in describing potential surface impacts that could occur as a result of leasing the federal mineral estate in the project area.

6.2 Appendix 2. State lease stipulations in the vicinity of the proposed Little Willow Creek lease area, Payette County, Idaho.

1. **Construction Notification.** Lessee shall notify and obtain approval from Idaho Department of Lands (IDL) prior to constructing well pads, roads, power lines, and related facilities that may require surface disturbance on the tract. Lessee shall submit a surface use plan of operations to IDL and obtain approval before beginning surface disturbance activities. Lessee shall comply with any mitigation measures stipulated in IDL's approval.
2. **Surface Owner Notification.** If the State does not own the surface, the Lessee must contact the owner of the surface in writing at least 30 days prior to any surface activity. A copy of the correspondence shall be sent to IDL.
3. **Unstable Soils.** Due to unstable soil conditions on this tract and/or topography that is rough and/or steep, surface use may be restricted or denied. Seismic activity may be restricted to surface shots.
4. **Metalliferous/Gem Lease.** This lease is issued subject to a prior existing State of Idaho metalliferous/gem lease. Lessee's rights to search, develop, and produce oil and gas may be restricted by such prior existing lease rights.
5. **Wildlife Concerns.** Potential wildlife conflicts have been identified for this tract. The applicant must contact the Idaho Department of Fish and Game (IDFG) in the area for advice on alleviating any possible conflicts caused by the Lessee's proposed activities. Documentation that IDFG requirements have been satisfied unless otherwise authorized by IDL is required. Additional mitigation measures may also be required.
6. **Threatened and Endangered Plant Species.** Plant species of concern have been identified on or near this tract. A vegetation survey in areas of proposed activity will be required prior to disturbance. Identified rare plant species will be avoided, unless otherwise authorized by the IDL.
7. **Threatened and Endangered Animal Species.** Animal species of concern have been identified on or near this tract. A survey in areas of proposed activity will be required prior to disturbance. Identified habitat of threatened and endangered species will be avoided, unless otherwise authorized by the IDL.
8. **Navigable Waters and Infrastructure.** Unless otherwise approved by IDL in writing, wells and related surface infrastructure, including new road construction, are prohibited within 1/4 mile of the mean high water mark of a navigable river, lake or reservoir, including direct tributary streams of navigable waterways, on or adjacent to this tract. No surface occupancy is allowed within the bed of a river, stream, lake or reservoir, islands and accretions or abandoned channels.
9. **Floodplain.** Due to the floodplain/wetlands area(s), surface use may be restricted or denied.
10. **Surveys.** If the lessee completes a successful oil and/or gas well, and if land title is disputed, the lessee shall fund professional land surveys as needed to determine the location and acreage encompassed by the spacing and/or pooling unit and the state lease acreage within that unit. Surveys shall be conducted by a licensed land surveyor acceptable to IDL, and shall be prepared pursuant to survey requirements provide by the IDL.
11. **Public Trust Lands.** This tract contains navigable riverbeds. No surface occupancy is allowed within the bed of the navigable river, abandoned channels, or on islands and

accretions. In addition, upon completion of a successful well, where river title is disputed, the Lessee will file an interpleader action under Rule 22 of Idaho Rules of Civil Procedure in the local District Court, or other court having jurisdiction, in which the leased lands are located for all acreage within the lease in which the title is disputed. The Lessee shall name all potential royalty claimants as defendants.

12. Existing Surface Uses. Due to existing surface uses (such as center pivots, wheel lines, etc.) development on this tract may be restricted.
13. Activity restrictions. No activity shall be allowed within 100 feet of any perennial or seasonal stream, pond, lake, wetland, spring, reservoir, well, aqueduct, irrigation ditch, canal, or related facilities without prior approval of the IDL.
14. Sage Grouse. Active sage-grouse lek(s) have been identified on or adjacent to this tract. No activities shall occur on the tract until the proposed action has been approved in writing by the Director of the Department. If surface activity is proposed on the tract, the Department will consult with the Director of Idaho Department of Fish and Game (IDFG) for their comments, concerns and recommendations. Additional mitigation measures may be required, including no-surface-occupancy buffers and/or timing restrictions, which may encompass part or the entire tract.
15. No Surface Occupancy. No Surface Occupancy shall be allowed on this tract.

6.3 Appendix 3. Legal description of lease parcels and applicability of Alternative C stipulations and lease notices.

Legal description of lease parcels.

Parcel	Legal Description			Acres
	Township/Range	Section	Quartersection/Lot	
A	T. 08 N R. 04 W	01	Lots 1-4; S½NE¼; S½NW¼; N½SE¼	364.78
		03	Lots 3 and 4; SW¼NW¼; W½SW¼	185.11
		04	Lots 1 and 2; S½NE¼; SE¼NW¼; SE¼; E½SW¼	426.53
		05	Lots 1-3; SE¼NW¼; E½SW¼	223.22
		08	E½NW¼	79.39
		12	NW¼; SW¼	312.44
		13	N½SE¼; SE¼SW¼	117.49
		24	NE¼NW¼	39.32
	Total			1,748.29
B	T. 09 N R. 04 W	28	N½NE¼; SW¼NE¼; NW¼; W½SE¼; N½SW¼	430.33
		32	SW¼NW¼	38.88
		33	NE¼NW¼; NW¼SE¼	80.03
	Total			549.25
C	T. 09 N R. 04 W	26	All	628.28
		27	E½NE¼; SW¼NE¼; W½NW¼; N½SE¼; SE¼SE¼	312.27
		34	NE¼; NE¼SE¼; S½SE¼	276.04
		35	N½NW¼; SW¼NW¼; SW¼SW¼	157.90
	Total			1,374.49
D	T. 09 N R. 03 W	18	Lots 2-4	125.56
		19	Lots 1 and 4; NE¼NW¼	123.06
	T. 09 N R. 04 W	13	S½NE¼; E½NW¼; S½	469.41
		24	N½NE¼; SW¼NE¼; S½SE¼; NW¼SE¼; W½	551.35
		25	W½	316.36
	Total			1,585.74
E	T. 09 N R. 03 W	17	S½NE¼; SE¼; W½	544.94
		18	NE¼; N½SE¼; SE¼SE¼	273.15
		20	NW¼NE¼; N½NW¼; SW¼NW¼	155.79
		29	N½NE¼; NE¼NW¼	117.55
	Total			1,091.43
Total				6,349.20

Applicability of stipulations and lease notices by parcel.

Stipulation/Lease Notice	Parcel ¹				
	A	B	C	D	E
Freshwater Aquatic Habitat CSU-1: 500' buffer from surface waters	Y	N	N	Y	Y
Freshwater Aquatic Habitat CSU-2: 100' buffer from surface waters	Y	N	N	Y	Y
Special Status Plants CSU -3: Types 1-4	P	Y	P	P	P
Big Game Range CSU-4: No surface use December 1 – March 31 any species; May 1 – June 30 antelope	Y	Y	Y	Y	Y
Sensitive Wildlife Species CSU-5: No surface use ≤0.75 miles of ferruginous and Swainson's hawk nests March 15 – June 30	P	P	P	P	P
Sensitive Wildlife Species CSU-6: No surface use ≤0.75 miles of osprey nests April 15 – August 31	P	P	P	P	P

Stipulation/Lease Notice	Parcel ¹				
	A	B	C	D	E
Sensitive Wildlife Species CSU-7: No surface use ≤ 0.25 miles of burrowing owl nests March 15 – June 30	P	P	P	P	P
Wildlife Species of Concern CSU-8: No surface use ≤ 0.75 miles of golden eagle nests February 1 – June 30	P	P	P	P	P
Wildlife Species of Concern CSU-9: No surface use ≤ 0.75 miles of prairie falcon nests March 15 – June 30	P	P	P	P	P
Wildlife Species of Concern CSU -10: No surface use ≤ 0.5 miles of heron rookery	P	P	P	P	P
Fragile Soils LN-1: Minimize adverse impacts to fragile soils	Y	Y	Y	Y	Y
Floodplain Management LN-2: Minimize adverse impacts to 100-year floodplain	Y	Y	N	N	N
Endangered Species S-1: Consultation and mitigation to protect listed species and critical habitat.	Y	Y	Y	Y	Y
Special Status Mammals LN-3: Minimize adverse impacts to SIDGS and pygmy rabbits.	P	P	P	P	P
Migratory Birds and Raptors LN-4: Compliance with MBTA by minimizing adverse impacts to migratory birds.	P	P	P	P	P
Migratory Birds and Raptors CSU-11: No surface use ≤ 1 mile of active bald eagle or peregrine falcon nest. No surface use December 1 – March 31 where wintering bald eagles or peregrine falcons are present.	P	P	P	P	P
Water Quality LN-5: Reduce impacts on water quality and quantity.	Y	Y	Y	Y	Y
Cultural Resources S-2: Comply with applicable statutes and executive orders.	Y	Y	Y	Y	Y
Cultural Resources LN-6: Cultural resource survey.	Y	Y	Y	Y	Y
Lands and Realty LN-7: Existing authorizations.	Y	Y	Y	Y	Y
Drainage LN-A: Wells on adjacent private lands.	Y	Y	Y	Y	Y
Split Estate LN-B: Surface use agreement required on split-estate.	Y	Y	Y	Y	Y
Paleontological Resources CSU-12: No surface use on identified resources.	Y	Y	Y	Y	Y
Paleontological Resources LN-7: Paleontological resource survey.	Y	Y	Y	Y	Y

¹ Y – applies to at least a portion of the parcel. P – potentially applies based on subsequent survey work. N – would not apply to that parcel.

6.4 Appendix 4. Idaho BLM special status animal species known to, or potentially occurring, in the Little Willow Creek lease area, Payette County, Idaho.

Type 1. Federally Listed Species and Critical Habitat: Includes species that are listed under the Endangered Species Act as Threatened (T) or Endangered (E) and designated critical habitats.

Type 2. BLM Special Status Species: Includes FWS Candidate (C), Delisted within 5-years (D), Proposed (P), Experimental Population (XN), and Proposed Critical Habitat (PCH); and BLM Sensitive Species.

The proposed lease area does not currently provide habitat for any Type 1 species. The proposed lease area is outside the range or typical habitat of the following special status animal species that occur in the Four Rivers Field Office, so they will not be considered further: Idaho giant salamander, Cassin's finch, Columbian sharp-tailed grouse, flammulated owl, harlequin duck, Lewis' woodpecker, mountain quail, bull trout, redband trout, white sturgeon, ashy pebblesnail, California floater, bighorn sheep, coast mole, fisher, grizzly bear, northern Idaho ground squirrel, Piute ground squirrel, and wolverine.

Note* NI=No impacts due to leasing and associated activities
DI=direct impacts due to leasing and associated activities
ID=indirect impacts due to leasing and associated activities

Common Name	Scientific Name	Habitat	Management Considerations
Amphibians			
Northern Leopard Frog	<i>Rana pipiens</i>	Wetlands, riparian areas, and adjacent uplands	DI – Adverse water quality impacts could cause mortality or affect breeding, etc. Discussed in Section 3.6.2 (Aquatic Species).
Western Toad	<i>Bufo boreas</i>	Ponds, streams, and adjacent uplands.	DI – Adverse water quality impacts could cause mortality or affect breeding, etc. Discussed in Section 3.6.2 (Aquatic Species).
Woodhouse's Toad	<i>Bufo woodhousii</i>	Grasslands, shrublands, agricultural areas, and ponds.	DI – Adverse water quality impacts could cause mortality or affect breeding, etc. Discussed in Section 3.6.2 (Aquatic Species).
Birds			
Bald Eagle	<i>Haliaeetus leucocephalus</i>	Winter migrant to lease area. Habitat includes lakes, reservoirs, streams, and uplands.	NI - No known nesting pairs are present. ID – Could occur for wintering birds where activities affect big game presence and winterkill. Discussed in Section 3.6.2 (Migratory Birds and Raptors).

Common Name	Scientific Name	Habitat	Management Considerations
Black Tern	<i>Chlidonias niger</i>	Open water lakes (>10 acres), ditches, and emergent wetlands.	ID – Activities could disturb migrating birds, but lease area doesn't provide nesting habitat.
Black-throated Sparrow	<i>Amphispiza bilineata</i>	Breeds in barren and grassy hillsides with scattered sagebrush and rabbitbrush.	DI/ID – Activities could reduce nesting foraging habitat, but lease area is on northern edge of species range.
Brewer's Sparrow	<i>Spizella breweri</i>	Sagebrush-steppe, nests in shrubs.	ID – Extensive sagebrush stands are not present; however, activities could affect species during migration.
Burrowing Owl	<i>Athene cunicularia</i>	Gently-sloping areas of shrubsteppe.	DI – Ground disturbing activities could destroy nests. ID - Activities could disturb or reduce prey species. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Ferruginous Hawk	<i>Buteo regalis</i>	Open country, nests on ground or rock outcrops, forages in shrubsteppe and grassland habitats.	ID – Activities could disturb or reduce prey species. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Golden Eagle	<i>Aquila chrysaetos</i>	Open country, nests on cliffs and artificial structures, forages in shrubsteppe and grassland habitats.	ID – Activities could disturb or reduce prey species. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Grasshopper Sparrow	<i>Ammodramus savannarum</i>	Shrubsteppe grasslands	DI/ID – Activities could reduce nesting and foraging habitat. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Greater Sage-grouse (C)	<i>Centrocercus urophasianus</i>	Sagebrush obligate.	NI - Outside currently delineated ranges, area lacks key habitat component.
Green-tailed Towhee	<i>Pipilo chlorurus</i>	Shrubsteppe in areas with high diversity of shrub species.	ID – Shrub stands are limited; however, activities could affect species during migration.
Loggerhead Shrike	<i>Lanius ludovicianus</i>	Shrubsteppe, open woodlands. Nests in tall shrubs and small trees.	ID – Activities could disturb or reduce nesting habitat and prey species. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Long-billed Curlew	<i>Numenius americanus</i>	Short-grass or mixed-prairie with flat rolling topography.	DI/ID – Activities could disrupt breeding, reduce nesting and foraging habitat. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Northern Goshawk	<i>Accipiter gentilis</i>	Aspen stands and conifer forests	NI – Habitat not present, occasional migrants could be affected by activities.
Olive-sided Flycatcher	<i>Contopus cooperi</i>	Montane or coniferous forests and riparian areas.	ID – Disturbance of birds using riparian areas during migration.
Sage Sparrow	<i>Amphispiza belli</i>	Sagebrush-steppe, nests in shrubs.	ID – Extensive sagebrush stands are not present; however, activities could affect species during migration.

Common Name	Scientific Name	Habitat	Management Considerations
Sage Thrasher	<i>Oreoscoptes montanus</i>	Sagebrush obligate	ID – Extensive sagebrush stands are not present; however, activities could affect species during migration.
Short-eared Owl	<i>Asio flammeus</i>	Large expanses of shrubsteppe and grasslands.	DI/ID – Activities could disrupt breeding, reduce nesting and foraging habitat. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Willow Flycatcher	<i>Empidonax trailii</i>	Dense willow riparian areas.	ID – Pollution could reduce prey species. Discussed in Section 3.6.2 (Migratory Birds and Raptors).
Yellow-billed Cuckoo (T)	<i>Coccyzus americanus</i>	Thick, wide riparian corridors, primarily dominated by cottonwoods. Known only as rare erratic breeder in the Snake River corridor mainly in southeast Idaho. Limited potential habitat occurs in area.	NI - Outside currently delineated ranges, area lacks key habitat component.
Mammals			
Big Brown Bat	<i>Eptesicus fuscus</i>	Rural areas and fields.	ID – Activities could reduce foraging success and prey habitat. Discussed in Section 3.6.2 (Bats).
Canyon Bat (formerly Western pipistrelle)	<i>Parastrellus hesperus</i>	Canyons and deserts in rock crevices, under rocks, and burrows	DI/ID – Activities could eliminate burrows, reduce foraging success and decrease prey habitat. Discussed in Section 3.6.2 (Bats).
Fringed Myotis	<i>Myotis thysanoides</i>	Caves, rock crevices, and open areas.	ID – Activities could reduce foraging success and prey habitat. Northeastern edge of range. Discussed in Section 3.6.2 (Bats).
Grey wolf	<i>Canus lupus</i>	Generalist habitat species. Follows big game herds.	ID - Could occur where activities affect big game presence.
Hoary Bat	<i>Lasiurus cinereus</i>	Trees, cavities, and open areas.	ID – Activities could reduce foraging success and prey habitat. Discussed in Section 3.6.2 (Bats).
Little Brown Bat	<i>Myotis lucifugus</i>	Forested lands near water, caves, and drier open areas.	ID – Activities could reduce foraging success and prey habitat. Discussed in Section 3.6.2 (Bats).
Long-eared Myotis	<i>Myotis evotis</i>	Coniferous forest and associated with forest-woodland riparian areas	ID – Insect prey base could be adversely affected by habitat alterations. Discussed in Section 3.6.2 (Bats).
Long-legged Myotis	<i>Myotis volans</i>	Coniferous forest and deserts; may change habitat seasonally	ID – Insect prey base could be adversely affected by habitat alterations. Discussed in Section 3.6.2 (Bats).
Pallid Bat	<i>Antrozous pallidus</i>	Arid, semi-arid uplands, sparsely vegetated grasslands, buildings, and caves.	ID – Activities could reduce foraging success and prey habitat. Discussed in Section 3.6.2 (Bats).

Common Name	Scientific Name	Habitat	Management Considerations
Pygmy Rabbit	<i>Brachylagus idahoensis</i>	Thick big sagebrush with deep soils.	DI/ID – Burrow destruction, vehicle mortality, foraging habitat. Discussed in Section 3.6.2 (Burrowing Mammals).
Silver-haired Bat	<i>Lasionycteris noctivagans</i>	Riparian areas, ponds, and streams.	ID – Activities could reduce foraging success. Pollution could reduce prey species. Discussed in Section 3.6.2 (Bats).
Southern Idaho Ground Squirrel (C)	<i>Spermophilus brunneus endemicus</i>	Sagebrush and grasslands	DI/ID – Burrow destruction, vehicle mortality, foraging habitat. Discussed in Section 3.6.2 (Burrowing Mammals).
Spotted Bat	<i>Euderma maculatum</i>	Rocky canyons and cliffs, forages over sagebrush.	ID – Insect prey base could be adversely affected by habitat alterations. Discussed in Section 3.6.2 (Bats).
Townsend's Big-eared Bat	<i>Plecotus townsendii</i>	Winter in stable-climate caves, forage over sagebrush.	ID – Insect prey base could be adversely affected by habitat alterations. Discussed in Section 3.6.2 (Bats).
Western Small-footed Myotis	<i>Myotis ciliolabrum</i>	Winters in lava tube caves and rock crevices, under boulders, and beneath loose bark in summer	ID – Insect prey base could be adversely affected by habitat alterations. Discussed in Section 3.6.2 (Bats).
Yuma Myotis	<i>Myotis yumanensis</i>	Wide elevation range including riparian, desert scrub and mesic woodland and forested areas.	ID – Insect prey base could be adversely affected by habitat alterations. Discussed in Section 3.6.2 (Bats).
Reptiles			
Great basin Black-collared Lizard	<i>Crotaphytus bicinctores</i>	Deserts, presence of rocks and boulders.	DI/ID – Vehicle mortality, loss of habitat and prey. Discussed in Section 3.6.2
Longnose Snake	<i>Rhinocheilus lecontei</i>	Deserts, grasslands, and rocky canyons.	DI/ID – Vehicle mortality, loss of habitat and prey. Discussed in Section 3.6.2
Western Ground Snake	<i>Sonora semiannulata</i>	Deserts with loose or sandy soils.	DI/ID – Vehicle mortality, loss of habitat and prey. Discussed in Section 3.6.2

7.0 Maps

If you are viewing this via the following link on the NEPA Register:

<https://www.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=renderDefaultPlanOrProjectSite&projectId=39064&dctmId=0b0003e8806d22d8>

Please find the maps in the home page's sidebar under Maps. Select "Map Package to accompany Little Willow Creek Protective Leasing EA".

8.0 Comment Responses

A Draft EA was made available to the public with a 30-day comment period (December 22, 2014 to January 21, 2015). Comments were received from the Idaho Conservation League (ICL); Randy and Thana Kauffman (K); the State of Idaho (SoI) including Office of Energy Resources, Department of Fish and Game, Office of Species Conservation, and Department of Environmental Quality; WildLands Defense (WLD); and WildEarth Guardians (WEG). Responses to summarized comments are provided below (organized by major topic) and the EA was modified as necessary to address some comments.

Land Use Plan

ICL-1: *The CRMP is outdated.*

WLD-7: *The CRMP is outdated and inadequate.*

WEG-7: *Leasing should be deferred until a new RMP is completed.*

Under normal circumstances, BLM offers lands nominated by the public for leasing, that have been identified in a land use plan as eligible and available for leasing. However, BLM regulations state that lands which are subject to drainage should be leased, even if they are otherwise unavailable for leasing (43 CFR 3120.1-1(d)). BLM has determined that the lands currently being considered for lease are or soon will be threatened by drainage of federally-owned oil and gas.

BLM IM 2010-117, Oil and Gas Leasing Reform Land Use Planning and Lease Parcel Reviews states: “There are other considerations that should be taken into account when determining the availability of parcels for lease.” Field offices should consider whether... “There is a risk of drainage to Federal mineral resources due to development of nearby non-Federal parcels if the parcel is not leased (based upon a determination made by a Petroleum Engineer or Petroleum Geologist).”

The 1988 CRMP provided a variety of stipulations related to issues and resources identified during that process (Section 2.3); however, BLM guidance allows for additional requirements to address changing resource concerns. According to IM 2010-117, “If a proposed modification to the terms of a stipulation changes the extent, but does not result in a new planning decision (e.g., the timing limitation protective radius increases from 2 miles to 3 miles, but the stipulation remains a moderate constraint), no plan amendment is required. The site-specific NEPA compliance documentation for the lease, however, may need to analyze the proposed stipulation modification if this analysis has not already been conducted in the NEPA documentation associated with the land use plan.” Lease notices are included in Alternative C to address additional resource concerns.

WLD-13 and WEG-6: *The CRMP does not support oil and gas leasing.*

The CRMP Final EIS analyzed the effects of designating areas open to gas leasing. This EA analyzes several alternatives, including Alternative C, which includes stipulations based on management direction from the CRMP. If post-lease actions are proposed (exploration and/or development), additional NEPA will be conducted to analyze site-specific effects of the proposed actions.

NEPA Adequacy

WLD-1: An EIS is needed to address the impacts.

The act of leasing (Alternatives B and C) would not constitute a major federal action that would significantly affect the quality of the human environment; therefore, an Environmental Impact Statement is not required. The BLM will determine the level of NEPA analysis needed when/if an APD is received. See also WLD-13 and WEG-6.

WLD-2: The cumulative effects areas are not adequate.

See cumulative effects sections in the EA. The CIAAs were selected based on BLM's knowledge of current oil and gas leasing in the area and the RFDS developed for this EA. It is difficult to speculate what will be nominated for oil and gas leasing in the future, as well as how much exploration and development will result. The RFDS created for this EA is BLM's best estimate and was analyzed in relative detail in the Environmental Consequences and Cumulative Impacts sections (Section 3.0).

WLD-5: Adequate baseline information for a variety of resources was not provided or considered; therefore, none of the alternatives can be adequately analyzed.

The interdisciplinary team used the best available resource data to create the baselines for analyzing alternatives (e.g., data from BLM, USDA/NRCS, IDFG/IFWIS, IDEQ, IDWR, EPA, US Census Bureau, etc.). The affected environment sections provide summaries of baseline data.

WLD-9: The BLM must consider a broad range of alternatives and mitigation actions to protect air, water, and natural resources and human health. The proposed protection measures are inadequate.

The alternatives analyzed provide a range of protection measures to federal mineral reserves and associated lands and resources. Direct impacts to resources associated with federal mineral reserve lands would not occur in Alternative A and indirect impacts would be limited. Direct impacts to resources associated with federal mineral reserve lands would also not occur in Alternative B; however, indirect impacts would occur. Direct and indirect impacts to resources associated with federal mineral reserve lands would occur in Alternative C; however, a variety of protective measures would help limit their degree. This EA begins to identify potential mitigation measures; however, APDs and associated NEPA analyses would help guide development of the most appropriate measures.

WLD-11: The proposed lease and associated EA represents a piecemeal approach and does not adequately address all alternatives.

The BLM is following its national guidance on the NEPA approach for leasing and subsequent, if any, drilling. Leasing and post-lease activities are not analyzed in the same NEPA document, since nationally, only about 10% of oil and gas leases ever get drilled. It is impossible to speculate precisely where, how, and what post-lease activities will occur, since a lease can be for up to 2,560 acres in size. BLM has taken a hard look at the impacts of leasing in this area with three alternatives and over 100 pages of analysis in this EA.

If an APD is proposed once a lease is issued, BLM will conduct a thorough and in-depth analysis that is site- and activity-specific. Mitigation measures in the form of enforceable Conditions of Approval would be attached to each APD. The BLM lease terms and stipulations, onshore orders, and regulations must be followed, and a performance bond must be accepted by BLM before any surface disturbing activities can occur. The BLM will monitor and inspect operations to ensure that the lessee is in compliance with BLM's requirements for both surface as well as down-hole resources.

WEG-1: Leasing the BLM parcels may enable expanded drilling on State and/or private lands. The range of alternatives clearly indicates that leasing would likely increase drilling opportunities on State and/or private lands. Existing (2) and proposed wells (2) occur on non-federal leases in the proposed lease area (Map 1). The RFDS and associated analyses recognize how many wells could be drilled within the lease area without (Alternative A – 2 new wells) or with (Alternatives B and C – 22 or 25 new wells, respectively) a federal lease. The current State well spacing of 1 well/640 acres was one of the factors used to determine the number of wells that could be drilled by alternative. The EA also recognizes that if federal minerals are omitted, then up to 25 new wells could potentially be drilled. With few exceptions (e.g., visual resource management and realty rights-of-way designations that do not apply to non-federal lands), potential impacts were described irrespective of land ownership.

WLD-12: The drainage explanation and current status of leases in the area are unclear.

WEG-5: Drainage is not a compelling reason for leasing.

Based on a current State of Idaho well spacing of 1 well/640 acres the BLM assumes that a well could drain mineral reserves in a 640 acre area regardless of ownership. Four existing wells and two proposed wells are within 0.5 miles of federal mineral resources. The existing wells are classified as “shut in pending a pipeline” indicating that they are producing wells. In a September 4, 2014 IOGCC hearing, the commission voted 4-1 to reconsider a request by Alta Mesa to omit federal mineral resources. If federal minerals are omitted from a drilling unit, BLM would be unable to collect the royalties it is due for its proportionate share of the drilling unit; therefore, the BLM considers these resources threatened by uncompensated drainage.

While 43 CFR 3162.2-2 offers several protective measures that BLM may take to avoid uncompensated drainage on unleased lands, they all require the cooperation of the owner-of-interest in the producing well, except for leasing. The BLM has offered several times to enter into a communitization or compensatory royalty agreement with Alta Mesa; however, Alta Mesa has rejected those offers. Existing and proposed wells provide some indication of non-BLM lease activity; however, the BLM does not have specific knowledge of existing leases in the proposed lease area.

WLD-14: The proposed action violates the laws and policies described in Section 1.6.

The BLM disagrees and finds that impacts to sensitive resources can be mitigated by application of stipulations, lease terms and conditions, onshore orders, and regulations for leasing.

Alternatives

K-1: Parcel A should be split into two parcels along the Little Willow Road.

The BLM will consider this comment prior to releasing the Notice of Lease Sale. The environmental impacts would be the same.

Vegetation

WLD-21: *Site specific surveys are lacking and impact magnitudes are discounted because of current conditions.*

The IDFG report information specific to the EOs in the proposed leasing area and CIAAs was added (Section 3.3.1). This information supports the current conditions and conclusions presented in the EA.

Air Resources

Table 6 in the Draft EA incorrectly used oxides of nitrogen values rather than nitrous oxides values for calculating greenhouse gas production. The nitrous oxides and consequently CO₂ eq values have been adjusted accordingly.

WLD-22: *The referenced air quality report is biased and inadequate.*

WLD-19: *Potential impacts to climate change are not adequately addressed.*

ICL-2: *Substantial increases in carbon dioxide equivalent emissions need to be mitigated.*

The BLM contracted the Kleinfelder Report to evaluate air quality impacts associated with oil and gas development activities for the Four Rivers RMP. The report provides detailed emission estimates of criteria pollutants, greenhouse gases (GHG), and key hazardous air pollutants (HAPs) anticipated to be released during each phase of oil and gas development for a representative oil and gas well in the western United States. The report acknowledges that defining a “representative” oil and gas well for the entire western U.S. is extremely challenging as there are numerous variables that can materially affect the emissions. Such variables include oil and gas composition, difficulty drilling the geologic formation, oil and gas production rate, equipment at the well site, emission controls, and the amount of produced water that may be associated with oil and gas production, among many others. Five well types (three natural gas wells and two oil wells), representative of different oil and gas basins in the western U.S., were evaluated.

The three types of natural gas wells were summarized as:

1. Uinta/Piceance Basin represents deep (15,000 feet) wells which may be drilled into shale with dry gas. These wells produce a moderate amount of condensate (420 gal/day) and 168,000 gal/yr of produced water. Methane emissions are estimated at 12.2 tons/yr (Table 13) and the Global Warming Potential (GWP) is estimated at 2,825 tons of CO₂ eq/yr.
2. San Juan Basin represents shallow (2,500-7,000 feet) wells with dry gas. These wells produce little to no condensate (210 gal/day) and 33,600 gal/yr of produced water. Other equipment included in the emissions inventory includes a pumpjack engine (to remove water) and a condensate tank. Average gas production per well, over the life of the well is estimated to be 27.8 MMscf/day (million cubic feet/day). Methane emissions

estimated at 6.1 tons per year. GWP is estimated at 791 tons of CO₂ equivalent.

3. Upper Green River Basin represents deep wells drilled into non-shale formations with wet gas, and higher condensate production (1,260 gal/day) and 126,000 gal/yr of produced water. More water vapor is present in the gas at this well, so each well site contains a dehydrator, separator, and line heater. The wells are drilled at relatively high density. Average gas production per well, over the life of the well is estimated to be 4.0 MMscf/day. Methane emissions estimated at 14.1 tons per year (Table 13). GWP is estimated at 3,194 tons of CO₂ equivalent.

Table 13. Total GHG emissions (tons/year) for two wells, Kleinfelder Report.

	Upper Green River Basin			San Juan Basin		
	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O
Construction Phase	33.84	0.001	0.0003	33.84	0.001	0.0003
Development Phase	1900.27	1.11	0.0498	561.61	1.05	0.0389
Operation Phase	947.96	12.99	0.0018	56.44	4.99	0.0004
Total	2882.07	14.10	0.0519	651.89	6.05	0.0396

For the Upper Green River Basin well, the following methane emissions (tons/year) are estimated, broken out by the development stage of the well:

Construction Phase 0.001 tons/yr

Sources: tailpipe of construction equipment, trucks

Development Phase (i.e. drilling and well treatment)

Sources:	Drill rig engine	0.03	(18 days, 24 hrs)
	Well frac engine	0.04	(7 days, 24 hrs)
	Frac flowback venting	0.94	(100 hrs)
	Workover venting	0.094	(once, 5000 Scf)
	TOTAL	1.104	tons methane/yr

Operational Phase (i.e. Production activities)

Sources:	Fugitive emissions	3.16	(97 valves, 348 connectors, 12 OE lines, 6 PR valves)
	Process heaters	0.0178	
	Wellsite tank flashing	0.552	
	Pneumatic devices:		
	Dump valves	8.896	four (4) valves, intermittent bleed
	Pneumatic controller	0.229	(low bleed)
	Pneumatic pumps	0.131	(chemical sandpiper, glycol)
	TOTAL	12.99	tons methane/yr

The construction and development (drilling) phases of oil and gas development are not major sources of methane emissions; however, methane releases during the development phase can

occur, resulting mainly from actuation of gas-operated valves during well operations and from fugitive gas leaks along the infrastructure required for the production and transmission of gas.

Several pneumatic devices are used at the wellhead to control the amount of fluid in the product. Raw natural gas must be free of oil and water before it is piped to a processing plant. This liquid removal takes place in a vessel called a separator, located at or near the wellhead. A pneumatic controller regulates the fluid level in the separator. When the fluid reaches a certain level, the controller's pilot directs gas to a diaphragm valve, which opens and dumps the liquid into a storage tank. Liquid separators at most older well sites have pneumatic controllers with dump valves that vent natural gas continuously. Newer valves (intermittent) vent only when fluid levels are actively being controlled, and emit only so much gas as is needed to open the dump valve so it can close again at the end of the dump cycle (from Devon Energy Corp. website "Tiny Valve- Big Difference").

The number of pneumatic devices used on a well is presumably determined by the amount of condensate (oil) and water produced. Since this information is not known, it is difficult to determine which gas well in the Kleinfelder Report is representative of conditions in the Little Willow Field. Because many of the input parameters for drilling and operations on the Little Willow Creek wells are unknown, BLM used the pollutant values for the Upper Green River Basin well in Table 6 of the EA. This represents a worst-case scenario for emissions at a natural gas well. A review of emissions inventories that have been conducted by other BLM offices in areas with more densely spaced wells than in Idaho (where spacing is limited to one well per 640 acres) reveals that the Kleinfelder Report used by BLM for this EA is conservative. It is likely that actual emissions at a Willow Field well head would be lower than the Upper Green River well (i.e., other inventories reported lower emissions values for GHG than what was used in this EA).

Implementation of mitigation measures (Section 3.4.3) at the APD processing stage could markedly reduce these emission values. The potential increases are substantial for Payette County, which currently produces limited amounts of Greenhouse Gases; however, when considered at larger scales [e.g., the four-county CIAA where they could account for a 1.7% increase over current levels or 0.001% of the 2012 US CO₂ eq production of 7,195 million tons (EPA: <http://www.epa.gov/climatechange/ghgemissions/gases.html>)], they represent negligible to minor increases. At the time an APD is submitted, additional NEPA analysis would be conducted, and a Condition of Approval can be attached to the APD that requires methane emissions not exceed a certain threshold, based on the best available information and analysis at that time.

The BLM is currently working at the national level to adopt new standards regarding venting and flaring to reduce natural gas waste and methane pollution. According to a DOI news release dated January 23, 2015, the new draft standards are scheduled to be put out for public comment this spring. According to the standard lease terms, the Willow Creek leases would be subject to those new standards, even if the leases are issued prior to adoption of the new standards.

SoI-3: The BLM needs to consider air and water quality impacts and appropriate stipulations to maintain them if leasing occurs.

Air and water quality impacts are discussed in Sections 3.4.2 and 3.5.2, respectively. While there would be no impacts associated with issuing leases, post-lease activities could be proposed that would result in impacts as discussed in those sections. Potential mitigation measures are identified in Sections 3.4.3 and 3.5.3. For air quality, these measures would be further refined based on site- and project-specific circumstances and would be imposed as APD Conditions of Approval, described in Section 3.4.3, as appropriate.

Section 2.3 of the EA provides lease stipulations and notices designed to protect water resources under Alternative C. For example, Freshwater Aquatic Habitat stipulations (CSU 1 and CSU 2) protect surface water quality in sensitive areas. Lease notices to inform the lessee that protective measures may be required if post-lease activities are proposed to minimize impacts within the 100-year floodplain (LN-2) and to minimize impacts to water quality and quantity (LN-5). Additionally, BLM is currently working at the national level to adopt new regulations regarding hydraulic fracturing. A final rule is anticipated in spring 2015. According to the standard lease terms, the Willow Creek leases would be subject to those new standards, even if the leases are issued prior to adoption of the new standards.

WLD-4: The pollution emission zone and local and regional airsheds have not been mapped or adequately analyzed.

WLD-23: The air quality cumulative effects analysis is inadequate.

The analysis areas include Payette County for localized impacts and a four county area (Ada, Baker, Canyon, and Payette) for CIAA. The analyses were conducted at county levels because the EPA provides information at that scale. These counties largely address the area you expressed concerns about (Treasure Valley) and the likely area pollutants would spread from the proposed lease. They include parts of two airsheds identified in Idaho; however, the EPA does not provide data by airsheds. The proposed lease area is 65 (Eagle Cap Wilderness), 67 (Hells Canyon Wilderness), or 72 (Sawtooth Wilderness) miles from the nearest Class 1 airshed areas. With the exception of GHG, which would affect resources at a much larger scale, pollutants from the development and production phase would typically not travel that far. North Ada County is a nonattainment zone for CO and PM₁₀. Maintenance plans are in place to address these issues (EPA 2015, Idaho nonattainment area plans, <http://yosemite.epa.gov/r10/airpage.nsf/283d45bd5bb068e68825650f0064cdc2/e2ab2cc6df433b8688256b2f00800ff8?OpenDocument>). Ada and Canyon counties are also considered areas of concern for PM_{2.5} and O₃. There are no nonattainment areas in eastern Oregon, but La Grande has a PM₁₀ maintenance plan in place. Without mitigation measures, the maximum RFDS of 25 wells add 0.1% and 0.7% respectively to CO and PM₁₀ pollutants in the CIAA.

Water Resources

WLD-3: Water depletion, quality, and protection issues were not adequately addressed.

WLD-24: Current water quality conditions need to be clarified.

The EA provides what is publicly known about water quality in the area (Section 3.5.1). The BLM is not aware of any further pesticide or other chemical testing of ground or surface waters

in the area. Water quality in Little Willow Creek especially is variable because of agricultural influences (dewatering for irrigation and potential pollutants in return flows). Until more specific information at the APD phase is available, the current analysis can only provide a broad range of impacts (Sections 3.5.2 and 3.5.4).

WLD-15: Aquifer and geological strata should be used to inform analyses on aquatic habitat impacts.

Information, primarily from IDWR and IDEQ, and analyses concerning aquifers are presented in Water Resources (Section 3.5) under the heading “Ground Water.” Aquatic habitat impacts are discussed Section 3.6.2. Stipulations concerning freshwater aquatic habitat are included as part of Alternative C.

WLD-4: The pollution emission zone has not been mapped.

The BLM is not clear what you mean by pollution emission zone. The identified CIAA (Section 3.5.4.1) is large enough to consider horizontal pollutant spread through the 10-year analysis period.

WLD-8: The EA does not adequately address fracking.

WEG-9: Impacts of hydraulic fracturing were not adequately addressed.

While BLM does not anticipate that hydraulic fracturing will be utilized in the Willow Field area, impacts are discussed in Water Resources (Section 3.5.2). If hydraulic fracturing is proposed on a well that has been drilled under an approved APD, it would be analyzed in much greater depth in a subsequent NEPA document. The Idaho Department of Lands has proposed a new rule currently pending the approval of the legislature, which has new requirements including water quality monitoring, should hydraulic fracturing be proposed. Additionally, BLM is currently working at the national level to adopt new regulations regarding hydraulic fracturing. A final rule is anticipated to be released in spring 2015. According to the standard lease terms, the Willow Creek leases would be subject to those new standards, even if leases are issued prior to adoption of the new standards.

Wildlife/Special Status Species

General

WLD-10: The variety of impacts was not adequately addressed.

Section 3.6.2.1 describes most of the impacts you identify including disturbance, mortality, changes in habitat quality, fragmentation, and pollution (including erosion and runoff) for the groups of animals they would likely affect. During the APD phase, when the types of development are more clearly identified, impacts would be more readily identified.

Special Status Species

WLD-20: Inventory requirements for special status species are inadequate.

SoI-1: The BLM needs to consider the presence of SIDGS and other special status species and take appropriate measures to inventory and protect them.

The BLM used the field visits, 2014 Idaho Fish and Wildlife Information System (which includes the referenced SIDGS data), and other data sources to determine presence of special status species in the proposed lease area. Impacts from the proposed actions are discussed in

Section 3.6.2. Sections 2.2, 2.3, 2.4, and 3.6.3 describe measures that would be taken to reduce or avoid impacts. Section 6 of the Lease Terms on the Offer to Lease and Lease for Oil and Gas (Form 3100-11) provide for requiring inventories of resources prior to ground disturbing activities. Lease specific stipulations (S1) and notices (LN-3 and LN-4) also provide for inventory and subsequent mitigation measures. The inventories would occur before and during the APD process and potential impacts would be analyzed in a subsequent EA.

WLD-6: Leasing would preclude conservation, enhancement, and restoration of sage-grouse and other special status species habitats.

The proposed lease area is outside any sage-grouse habitat designation; therefore, it would not be a restoration priority for that species. SIDGS are the most prevalent special status species in the proposed lease area. Although development and production activities could degrade habitat, they would not preclude habitat restoration activities once disturbance factors have been stabilized and restoration could be a requirement during the abandonment phase. Efforts to maintain or enhance SIDGS habitat would likely benefit most other special status species.

WLD-16: The migratory bird and raptor provisions are outdated and scientifically indefensible. The winter range avoidance period (November 15 to May 15), which affects 94% of the federal mineral reserve lands, would provide more widespread protections during early breeding and nesting periods for periods not addressed by migratory bird and raptor nesting protections.

WEG-2: Greater sage-grouse were not adequately addressed.

The CRMP did not provide leasing stipulations for sage-grouse. Because of historic wildfires and human activities (e.g., livestock grazing), the proposed lease area does not provide suitable sage-grouse habitat. The distances to identified sage-grouse habitat (5-6.5 miles to sagebrush/perennial grass dominated communities [Key, Preliminary General, and Preliminary Priority habitats]) and active leks (9.5 miles)^E are substantially greater than the 3 mile buffer recommended by Dr. Braun. The proposed lease would not affect sage-grouse in the area; therefore, it would not affect listing decisions.

WEG-4: Impacts to other sensitive species, especially sagebrush obligates were not adequately addressed.

Impacts to representative special status species, including SIDGS and sagebrush obligates, are discussed in Sections 3.3.2 and 3.6.2 and Appendix 4. The proposed lease area would affect approximately 4% of the current distribution of SIDGS (based on minimum convex polygon of current and historic locations, assuming 66% of the polygon is suitable habitat). Shrub-dominated communities occur on up to 25% of the lease area, but typically occur in isolated stands (see Figure 1 and Figure 2).

Big Game

SoI-2: The BLM needs to clarify where big game winter range stipulations would apply, consider impacts to private lands that development would have, and provide adequate measures to avoid disturbance.

The CRMP used the term crucial; therefore, it was carried forward into this document. The BLM used IDFG data (Map 6) to delineate current big game winter range, combining mule deer,

elk, and pronghorn ranges into one polygon. For Alternative C, the winter timing restriction would apply to all federal mineral estate in winter range (approximately 6,053 acres or 94% of leased lands). Wildlife depredation is discussed in Sections 3.6.2 and 3.14.2. The winter timing restriction was expanded to November 15 to May 15. This expansion is within the 60-day flexibility allowed by BLM policy.

WEG-3: Impacts to pronghorn winter range were not adequately addressed.

The EA (Section 3.6.1, Map 6) describe winter ranges for pronghorn, mule deer, and elk. A combination of all three was used for analysis purposes. The CRMP recognized that winter range delineations could change through time^B; therefore, the winter ranges used in this analysis were developed in cooperation with IDFG using current monitoring information and represent a larger area than was identified in the CRMP. The analyses indicate moderate to major adverse impacts could occur from the proposed levels of development in Alternatives B and C (Sections 3.6.2.3 and 3.6.2.4). The cumulative impacts of changes in habitat conditions from oil and gas production and development and other activities are addressed in Section 3.6.4.

The no surface use limitation (CSU-4) would apply to the exploration, drilling, development and production, and abandonment phases and would cover all activities (e.g., surface disturbing and disruptive). Your concern about exceptions is addressed in Section 3.6.2.4. The proposed lease area is on the periphery of winter range; therefore, it would not affect migration corridors.

Recreation

WLD-17: Impacts to and by recreationists were not adequately addressed.

Access to the isolated parcels of BLM-administered lands occurs through private lands. They are near agricultural lands and provide little opportunity for those seeking solitude. Impacts from increased access were addressed in Sections 3.6, 3.7, 3.8, 3.9, and 3.14.

Visual Resources Management

WLD-4: The visual analysis is inadequate.

The BLM only manages visual resources on BLM-administered lands. Impacts to visual resources on BLM-administered lands have been analyzed in Section 3.10.

Social and Economic

ICL-3: Social and economic impacts to landowners were not adequately addressed.

Social and economic impacts, including land values and use, are addressed in Sections 3.5, 3.13, and 3.14. Private landowners in and adjacent to the proposed lease area have been involved in this process. The concerns raised during the July 2014 scoping period were addressed in the EA. One landowner commented on the EA regarding how parcels were delineated. Analyses during the APD phase will provide more in-depth assessment of these issues.

WLD-4: The noise zone has not been mapped.

Noise impacts to wildlife and humans are discussed in Sections 3.6.2 and 3.14, respectively. Noise is an impact that is more appropriately analyzed in the NEPA for an APD, and can be mitigated by applying a Condition of Approval requiring noise reduction measures, if needed.

WEG-8: *The social cost of carbon needs to be addressed.*

The social cost of carbon is addressed in Air Resources and Social and Economic sections 3.4.2 and 3.14.2, respectively.

Other Resources

WLD-18: *Paleontological resources are ignored.*

A paleontological resource stipulation (CSU-12) was added to Alternative C (Section 2.3) and the affected environment and environmental consequences were described (Section 3.8).

Exhibit 14

Temperature impacts on economic growth warrant stringent mitigation policy

Frances C. Moore^{1,2*} and Delavane B. Diaz³

Integrated assessment models compare the costs of greenhouse gas mitigation with damages from climate change to evaluate the social welfare implications of climate policy proposals and inform optimal emissions reduction trajectories. However, these models have been criticized for lacking a strong empirical basis for their damage functions, which do little to alter assumptions of sustained gross domestic product (GDP) growth, even under extreme temperature scenarios^{1–3}. We implement empirical estimates of temperature effects on GDP growth rates in the DICE model through two pathways, total factor productivity growth and capital depreciation^{4,5}. This damage specification, even under optimistic adaptation assumptions, substantially slows GDP growth in poor regions but has more modest effects in rich countries. Optimal climate policy in this model stabilizes global temperature change below 2°C by eliminating emissions in the near future and implies a social cost of carbon several times larger than previous estimates⁶. A sensitivity analysis shows that the magnitude of climate change impacts on economic growth, the rate of adaptation, and the dynamic interaction between damages and GDP are three critical uncertainties requiring further research. In particular, optimal mitigation rates are much lower if countries become less sensitive to climate change impacts as they develop, making this a major source of uncertainty and an important subject for future research.

Integrated assessment models (IAMs) have traditionally captured the negative impacts of climate change with a damage function that relates global temperature change to a loss of current economic output. This formulation captures the transient effects of climate on the economy such as lost agricultural output, increased cooling demand, or lower worker productivity due to hotter temperatures^{7–9}. Factors of production, namely labour and capital, and their total factor productivity (TFP) are not directly impacted, meaning that climate change has no effect, or only a very weak effect, on GDP growth. Two IAMs recently used for the US government social cost of carbon (SCC) estimate, FUND and PAGE, assume that GDP growth is entirely exogenous^{10,11}. In the DICE model, labour and TFP are specified exogenously and capital formation is determined through endogenous investment decisions⁵; temperature shocks can therefore alter economic growth through capital stock reductions, but this effect is small and indirect¹².

Damages from climate change that directly affect growth rates have the potential to markedly increase the SCC because each temperature shock has a persistent effect that permanently lowers GDP below what it would otherwise be (Supplementary Fig. 1). Continued warming therefore has a compounding effect over time, so that even very small growth effects result in much larger

Table 1 | Parameters used to calibrate the gro-DICE damage functions, reported in Dell *et al.* Table 3, column 4 (ref. 4).

	Effect 1 °C temp increase on GDP growth rates (γ_0)	Effect 1 °C temp increase on economic output (β_0)
Poor	–1.171 pp	–0.426%
Rich	–0.152 pp	0.371%

This specification includes 10 temperature lags and no precipitation controls. A brief summary of the estimation strategy used in ref. 4 is given in the Supplementary Information. pp: percentage point.

impacts than the traditional damage formulation¹². Examples of pathways by which temperature could affect the growth rate of GDP include damage to capital stocks from extreme events, reductions in TFP because of a change in the environment that investments were originally designed for, or slower growth in TFP because of the diversion of resources away from research and development and towards climate threats¹. Empirical evidence that these impacts exist is mounting. Two studies have found a reduced-form relationship between temperature shocks and GDP growth^{4,13}, and other studies have demonstrated plausible pathways including increasing conflict risk¹⁴ and changes in labour supply¹⁵. Previous work has demonstrated that DICE results are sensitive to the inclusion of growth impacts^{12,16}, but no previous studies have calibrated these damages using empirically grounded results from the econometrics literature. Given the potentially first-order impacts of these growth effects, understanding their implications for climate policy is of critical importance.

Here we examine alternative formulations of the DICE damage function based on empirical estimates of the impact of inter-annual temperature variability on national economic output and growth rates by Dell and colleagues⁴. They find large, statistically significant negative effects of hot temperatures on growth rates in poor countries, smaller effects in rich countries, and mixed effects on output (Table 1). To implement these parameters in an IAM, we develop a two-region version of DICE (ref. 17; DICE-2R). We then modify the damage pathway so that warming affects either TFP growth or capital depreciation as per results in ref. 4 (gro-DICE) and investigate sensitivities to the parameters used by Dell *et al.*⁴ (Methods). We present results of the TFP pathway here, but the capital pathway gives quantitatively similar results and is discussed further in the Methods and Supplementary Information.

As Dell *et al.*⁴ use transient and largely unanticipated weather shocks in their estimation, the growth-rate sensitivities (reduction

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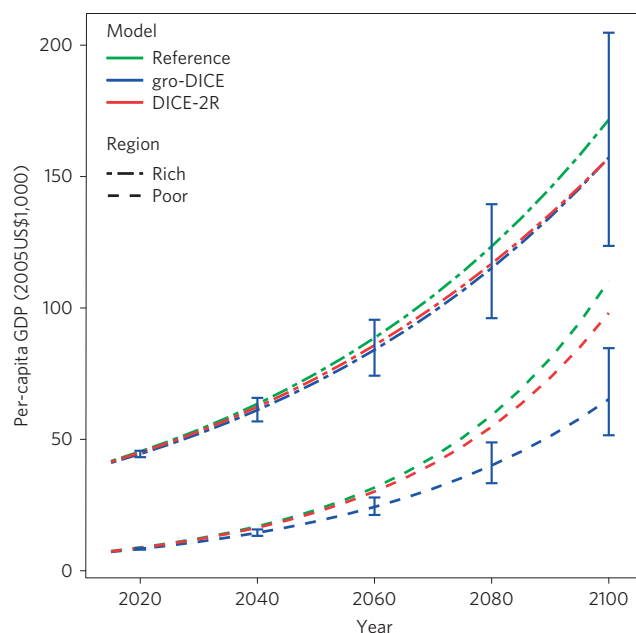


Figure 1 | Per-capita GDP for rich and poor regions for the reference (no damages) run and DICE-2R and gro-DICE models under business-as-usual. Temperature in the reference reaches 5 °C above pre-industrial by 2100. The error bars show results using \pm one standard error (68% confidence interval) around the growth-rate damages reported in ref. 4 (Table 1).

in growth rate from 1 °C of warming) shown in Table 1 are the short-run impacts of higher temperatures. Long-run impacts of the permanent warming associated with climate change could be either larger (owing to intensification) or smaller (owing to adaptation) than this short-run effect⁹, although several studies show evidence for some adaptation^{18–20}. We adopt optimistic adaptation assumptions in gro-DICE by assuming that the long-run effect of temperature on GDP growth is zero and that the short-run impacts decay exponentially at a constant adaptation rate (Methods). As there is a very limited empirical basis for the rate of adaptation, we assume a value of 10% per year and examine sensitivity to this parameter (Supplementary Fig. 2).

Figure 1 shows the trajectory of per-capita GDP under business-as-usual for the reference (no climate damages), DICE-2R and gro-DICE models. Temperatures exceed 4.5 °C by 2100, causing economic losses in both models with damages. Impacts in DICE-2R are modest because impacts are transient and offset by sustained growth in TFP, labour and capital: the difference from reference GDP is less than 12% in both poor and rich regions by 2100. In contrast, the growth effects in gro-DICE compound over the century, leading to much larger impacts. The average annual growth rate in poor regions is cut from 3.2% to 2.6%, which means that by 2100 per-capita GDP is 40% below reference. The much smaller growth effects in rich countries, combined with the fact that warming slightly improves economic output, means the gro-DICE and DICE-2R timepaths are very similar in the rich region. Figure 1 also shows the effect of increasing and decreasing the growth-rate sensitivity parameter by one standard error. The large negative impact in poor countries is robust, but uncertainty around the magnitude of growth impacts in rich regions means that they could benefit from warming.

Figure 2 shows results if mitigation levels are chosen to maximize global discounted social welfare. Optimal climate policy in DICE-2R demonstrates a classic ‘policy-ramp’ in which mitigation efforts increase gradually over the century, with emissions peaking in

2060 and warming of over 3.5 °C by 2100. In contrast, optimal mitigation in gro-DICE consists of eliminating emissions in the very near future to stabilize global temperatures below 2 °C above pre-industrial. Even optimistic assumptions about temperature effects on GDP growth (the upper bound on the error bars in Fig. 2) lead to more stringent near-term mitigation than DICE-2R and elimination of emissions by 2070. The findings of near-term decarbonization and global temperature stabilization below 2 °C are robust to changes in the adaptation rate, which we vary between 0 and 20% per year (Supplementary Fig. 3). A variant of gro-DICE in which temperatures affect the depreciation of capital rather than TFP growth also gives quantitatively similar results (Supplementary Fig. 4).

The motivation for rapid decarbonization can be illustrated with the high SCC in gro-DICE (Fig. 2). One additional ton of CO₂ emitted in 2015 reduces net social welfare by US\$33 in DICE-2R but by US\$220 in gro-DICE. This value is higher both because climate damages are larger in gro-DICE and because slower economic growth leads to a lower discount rate⁵. The trajectory of the SCC over time has an inverted U-shape determined by relative changes in the marginal utility of emissions and the marginal utility of consumption over time (Supplementary Fig. 5). The additional mitigation undertaken in the gro-DICE optimal run does reduce damages compared to business-as-usual, but poor countries still suffer substantial impacts, with per-capita GDP in 2100 still 20% lower than the reference.

Our results thus far assume a static damage function, but the relationship between economic growth and temperature is likely to change over time. Dell *et al.*⁴ find much higher sensitivity of GDP growth rates to warming in poor countries than in rich (Table 1), which could result from two possible mechanisms. One is that high sensitivity may result from biophysical temperature thresholds, beyond which warming becomes particularly damaging^{8,21}. As poor countries are, on average, hotter than rich countries, they are exposed more frequently to damaging temperatures and therefore show higher sensitivity to temperature. Under this mechanism, the sensitivity of rich countries would increase as they warm. Alternatively, higher temperatures may be more damaging in poor countries because their economies are reliant on climate-exposed sectors such as agriculture and natural resource extraction, or because risk management options such as insurance or air conditioning are not as widely available. In this case we would expect the sensitivity of poor regions to warming to decrease as per-capita GDP increases. We call these two mechanisms the ‘temperature’ and ‘resilience’ mechanism respectively and implement each separately in gro-DICE by making the growth-rate damage parameters a function of either temperature change or per-capita GDP (Methods).

Although both the temperature and resilience mechanisms could explain the different sensitivities of rich and poor countries to higher temperatures observed today, they have contrasting implications for how damages might evolve over time and for optimal climate policy (Fig. 3). As mitigation is already so high in the standard gro-DICE model, adding the temperature mechanism has little additional effect. However, the resilience mechanism results in a very different mitigation trajectory. Early mitigation serves to slow the rate of climate change but is later relaxed because of the benefits of economic growth in poor regions in terms of reduced sensitivity to warming (Supplementary Fig. 6). Once sensitivity in poor regions stabilizes in 2070 at the level observed at present in rich countries, mitigation gradually increases so that emissions peak in 2120 and are eliminated by 2150, stabilizing global temperatures at 6 °C above pre-industrial. The evolution of the damage function over time therefore has important policy implications for balancing the dual priorities of increasing resilience through economic growth and decarbonization.

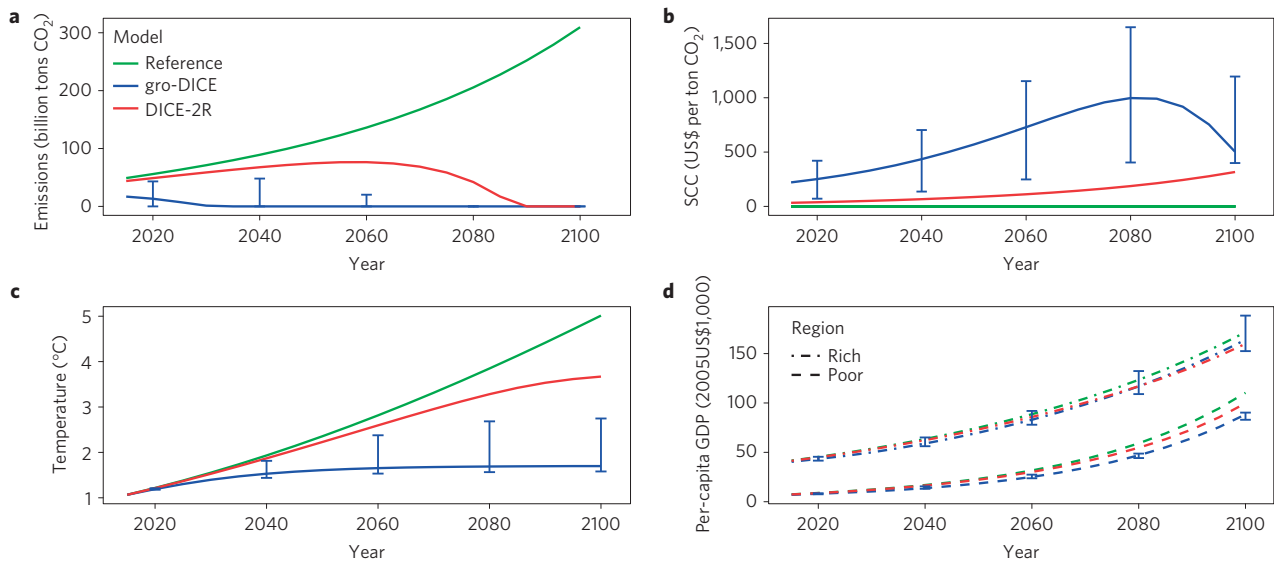


Figure 2 | Results of Pareto optimal runs of DICE-2R and gro-DICE. a–d, Annual global emissions (a), SCC (b), global temperature (c) and regional per-capita GDP (d). The error bars show results from Pareto optimal runs of gro-DICE using \pm one standard error (68% confidence interval) around the growth-rate sensitivity reported in ref. 4. The reference is defined as a model run with no climate damages and therefore has zero SCC by definition.

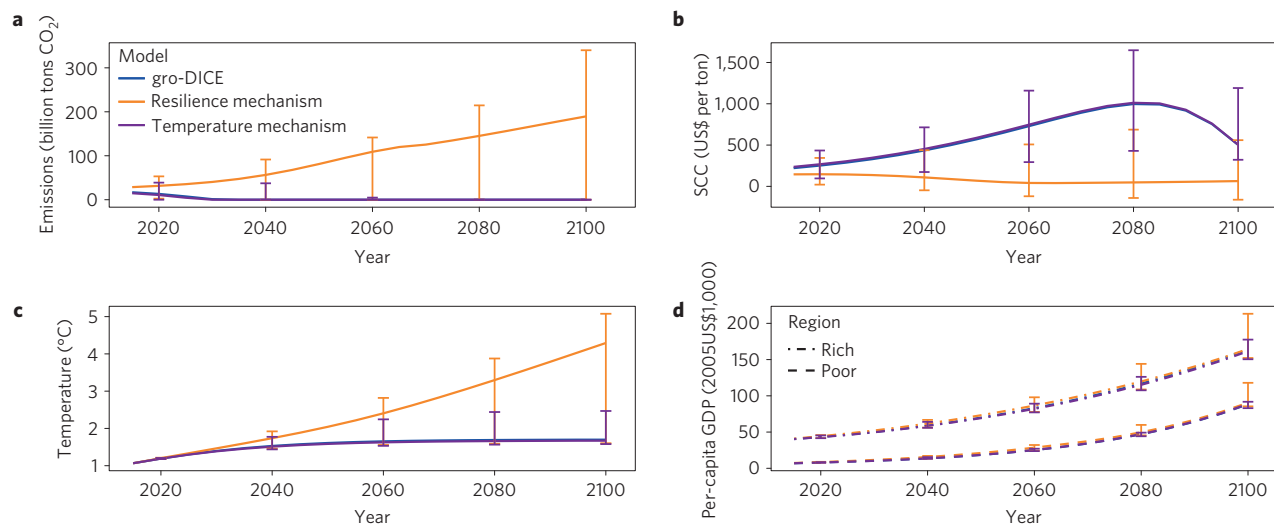


Figure 3 | Results of Pareto optimal runs of gro-DICE, and versions of gro-DICE that include dynamic damage functions based on either the temperature or resilience mechanisms (Methods). a–d, Annual global emissions (a), SCC (b), global temperature (c) and regional per-capita GDP (d). The gro-DICE and temperature mechanism lines are indistinguishable. The error bars show Pareto optimal runs using \pm one standard error (68% confidence interval) around the growth-rate sensitivity reported in ref. 4.

One limitation of the DICE model is the simplicity of the reduced-form mitigation function^{5,22}. First, the mitigation level can fluctuate freely, with no expansion constraint from period to period. This fails to capture real-world inertia, represented in other energy system IAMs, which limits the rate of decarbonization owing to delayed availability of low-emitting technologies, construction lead times, stranded assets, or other capital turnover factors^{23,24}. Second, the simple mitigation cost function constitutes a claim on current output without affecting the factors of production or TFP. Mitigation at the rate implied by gro-DICE could well impose its own persistent impacts on economic growth, as suggested by some previous research²⁵. Although gro-DICE was designed to investigate the effects of temperature on growth, it does not include the converse effect of mitigation, something beyond the scope of this paper but a priority for future research. For both these reasons, the results regarding very rapid, near-term mitigation should not be

over-interpreted as evidence that such a policy would necessarily be economically optimal. Nevertheless, the findings that temperature effects on growth rates imply much larger climate damages and, correspondingly, more stringent mitigation than is justified by transient impacts on economic output are probably robust to more realistic modelling of mitigation costs.

Historically, attention has narrowly focused on climate sensitivity and the discount rate in driving uncertainty in IAM results^{26,27}. We compare these two uncertainties with the new factors introduced in this paper. Figure 4 shows that the magnitude of GDP growth-rate sensitivity, the rate of adaptation, and how sensitivity to warming changes with per-capita GDP are at least as important as climate sensitivity and the pure rate of time preference in determining optimal climate policy over the next century.

This paper has shown that allowing climate change to directly affect economic growth through impacts to TFP or capital can

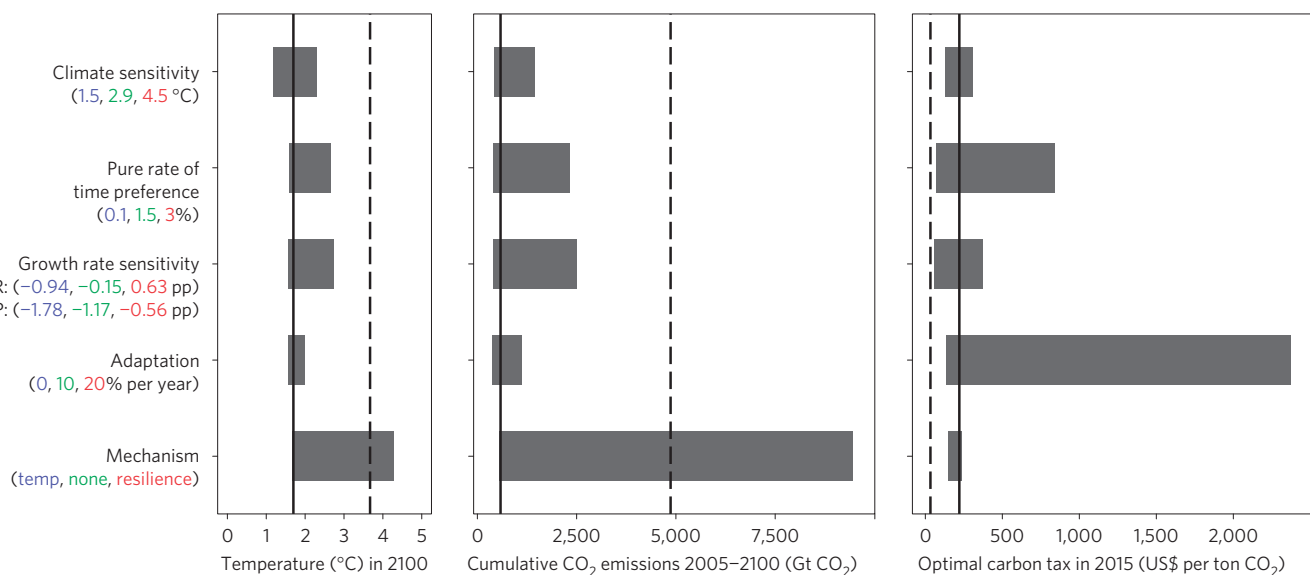


Figure 4 | Sensitivity of three key indicators of twenty-first century climate policy to climate sensitivity, the pure rate of time preference (PRTP), the sensitivity of economic growth rates to temperature, adaptation rate, and the temperature or resilience mechanisms. The lower, main and upper values of the parameter range are labelled in blue, green and red, respectively. The climate sensitivity range is derived from the 66% confidence (likely) interval given by the Intergovernmental Panel on Climate Change Fifth Assessment Report³⁰. The values for the pure rate of time preference do not correspond to a confidence interval, but to noted low and high values from the literature. The growth-rate sensitivities are based on \pm one standard error (68% confidence interval) as reported in ref. 4. Results for the gro-DICE model (solid line) and DICE-2R model (dashed line) are shown for comparison.

significantly increase the SCC and the optimal rate of near-term mitigation. This finding holds for empirically derived estimates of the magnitude of temperature effects on growth rates using optimistic adaptation assumptions, and is robust to uncertainty in the sensitivity parameter and the rate of adaptation, but not to the mechanism driving different growth-rate impacts in rich and poor regions. Although the simplified representation of mitigation in DICE means the optimal level of near-term mitigation may be overestimated here, the higher marginal damage of CO₂ emissions should be robust to higher mitigation costs. The sensitive dependence of model results on the magnitude of growth-rate impacts, the adaptation rate, and the interaction of temperature sensitivity with per-capita GDP indicate that these topics should be a priority for future empirical work. If further studies confirm that climate change has the potential to adversely affect TFP, capital stocks or labour supply then aggressive, near-term mitigation could well be warranted.

Methods

To study the growth effects as presented in Dell *et al.*⁴ (DJO in this section) we created a two-region version of DICE (DICE-2R). The rich and poor regions are parameterized on the basis of output-weighted regional values from the 2010 RICE model^{5,17} (Supplementary Table 1). DICE-2R chooses mitigation and savings so as to maximize the discounted sum of utility in both regions, weighted by regional Negishi weights²⁸. We also altered DICE by fixing emissions in 2005 and 2010, making 2015 the first year when mitigation is possible. As the parameterization of the rich and poor regions in DICE-2R, although consistent with RICE2010, differs from the DICE-2013R aggregate, DICE-2R does not exactly reproduce the most recent DICE results⁵. Specifically, the slightly faster TFP growth in DICE-2R means that incomes and emissions are higher in DICE-2R than in DICE-2013R in the second half of the twenty-first century.

We investigate two alternative pathways by which warming could affect economic growth: slowing the growth of TFP or accelerating depreciation of the capital stock. For the first pathway, climate damages impact the growth rate of TFP, reflecting the fact that climate change could affect the productivity of the research sector or existing investments¹²:

$$A_{j,t} = (1 + j_{\text{TFP},t} - r_{\text{DJO},t})^{\Delta t} A_{j,t-1} \quad (1)$$

$$j_{\text{DJO},t} = \tilde{\gamma}_0 T_t$$

where $A_{j,t}$ is TFP in region j in time period t , j_{TFP} is the exogenous annual TFP growth rate, T is the global temperature change from pre-industrial, Δt is the model time step, and $\tilde{\gamma}_0$ is the regional growth-rate sensitivity to temperature, calibrated to reproduce the DJO result (Table 1). Calibration is necessary because economic growth is not completely exogenous in DICE but is partly determined by an endogenous capital stock, meaning that reductions in TFP affect economic growth both through lower productivity and through lower capital. Details on the calibration are given in the Supplementary Information. The gro-DICE model also includes transient impacts of temperature on regional output estimated by DJO ($\beta_0 T_t$, Table 1), but this effect is small compared with the growth-rate damages.

The second pathway assumes climate damages fall on the capital depreciation rate. This simulates the impact of climate change on physical infrastructure through more frequent or larger extreme events or on institutional capital through, for example, increased risk of civil conflict¹⁴. We calibrate the relationship between temperature change and depreciation rate for the DJO results for values of capital stock, investment, TFP and labour in the reference run for a range of temperatures up to 6 °C (calibration details in Supplementary Information and Supplementary Fig. 9). This gives a concave, quadratic function relating warming and depreciation rate (Supplementary Fig. 10). We find comparable implications for climate policy along both the TFP and depreciation pathways. In reality, both impact pathways (as well as others) are likely to be important in determining climate change damages, but we present them separately here for clarity and because of the lack of empirical studies on their relative roles.

We model adaptation in gro-DICE using an exponential decay curve in which the initial impact of a change in temperature (determined by parameters calibrated to the DJO results) declines over time at the rate of adaptation. We introduce a new variable, the effective temperature, which is the sum of all residual temperature shocks:

$$ET_t = \sum_{i=1850}^t (T_i - T_{i-1}) e^{-a(t-i)}$$

where ET_t is the effective temperature at time t , T_i is the temperature in year i , and a is the rate of adaptation. For runs with a positive adaptation rate, ET_t replaces T_t in the calculation of damages (equation (1)). As there is a very limited empirical basis for the rate of adaptation, we use a value of 10% per year and vary it between 0 and 20% per year in a robustness check. Ten per cent per year is equivalent to a 95% reduction in the impact of a temperature shock after a 30-year adjustment period (Supplementary Fig. 2). The contribution to effective temperature of temperature change before the start of the model time horizon is based on the global surface temperature record since 1850 (ref. 29). The effective

temperature rather than absolute temperature is then used to define damages on output and TFP or capital. This formulation means that impacts depend both on the magnitude and the rate of temperature change because faster warming results in larger disequilibrium and therefore higher adjustment costs.

The temperature and resilience mechanisms are implemented such that the growth-rate damage parameters $\tilde{\gamma}_0$ are a function of either temperature or per-capita GDP, respectively. In the temperature mechanism, sensitivity in poor regions remains constant but increases with warming in rich regions, not exceeding the sensitivity observed at present in poor regions (Supplementary Fig. 11). The resilience mechanism causes sensitivity in poor regions to decrease until they reach the per-capita GDP of rich regions today, reducing damages from warming over time as poor regions develop (Supplementary Fig. 12).

The effect of parametric uncertainty in five factors is investigated by independently varying each parameter from its reference value to a high or low value using one-at-a-time sensitivity analysis (Fig. 4). The uncertainties captured and not captured by this approach are discussed more fully in the Supplementary Information.

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Author contributions

F.C.M. and D.B.D. designed the analysis. D.B.D. performed the analysis. F.C.M. and D.B.D. analysed results and wrote the paper.

Additional information

Supplementary information is available in the online version of the paper. Reprints and permissions information is available online at www.nature.com/reprints. Correspondence and requests for materials should be addressed to F.C.M.

Competing financial interests

The authors declare no competing financial interests.

Exhibit 15



THE COST OF DELAYING ACTION TO STEM CLIMATE CHANGE

July 2014



Executive Summary

The signs of climate change are all around us. The average temperature in the United States during the past decade was 0.8° Celsius (1.5° Fahrenheit) warmer than the 1901-1960 average, and the last decade was the warmest on record both in the United States and globally. Global sea levels are currently rising at approximately 1.25 inches per decade, and the rate of increase appears to be accelerating. Climate change is having different impacts across regions within the United States. In the West, heat waves have become more frequent and more intense, while heavy downpours are increasing throughout the lower 48 States and Alaska, especially in the Midwest and Northeast.¹ The scientific consensus is that these changes, and many others, are largely consequences of anthropogenic emissions of greenhouse gases.²

The emission of greenhouse gases such as carbon dioxide (CO₂) harms others in a way that is not reflected in the price of carbon-based energy, that is, CO₂ emissions create a negative externality. Because the price of carbon-based energy does not reflect the full costs, or economic damages, of CO₂ emissions, market forces result in a level of CO₂ emissions that is too high. Because of this market failure, public policies are needed to reduce CO₂ emissions and thereby to limit the damage to economies and the natural world from further climate change.

There is a vigorous public debate over whether to act now to stem climate change or instead to delay implementing mitigation policies until a future date. This report examines the economic consequences of delaying implementing such policies and reaches two main conclusions, both of which point to the benefits of implementing mitigation policies now and to the net costs of delaying taking such actions.

First, although delaying action can reduce costs in the short run, on net, delaying action to limit the effects of climate change is costly. Because CO₂ accumulates in the atmosphere, delaying action increases CO₂ concentrations. Thus, if a policy delay leads to higher ultimate CO₂ concentrations, that delay produces persistent economic damages that arise from higher temperatures and higher CO₂ concentrations. Alternatively, if a delayed policy still aims to hit a given climate target, such as limiting CO₂ concentration to given level, then that delay means that the policy, when implemented, must be more stringent and thus more costly in subsequent years. In either case, delay is costly.

These costs will take the form of either greater damages from climate change or higher costs associated with implementing more rapid reductions in greenhouse gas emissions. In practice, delay could result in both types of costs. These costs can be large:

¹ For a fuller treatment of the current and projected consequences of climate change for U.S. regions and sectors, see the Third National Climate Assessment (United States Global Change Research Program (USGCRP) 2014).

² See for example the Summary for Policymakers in Working Group I contribution to the Intergovernmental Panel on Climate Change Fifth Assessment Report (IPCC WG I AR5 2013).

- Based on a leading aggregate damage estimate in the climate economics literature, a delay that results in warming of 3° Celsius above preindustrial levels, instead of 2°, could increase economic damages by approximately 0.9 percent of global output. To put this percentage in perspective, 0.9 percent of estimated 2014 U.S. Gross Domestic Product (GDP) is approximately \$150 billion. The incremental cost of an additional degree of warming beyond 3° Celsius would be even greater. Moreover, these costs are not one-time, but are rather incurred year after year because of the permanent damage caused by increased climate change resulting from the delay.
- An analysis of research on the cost of delay for hitting a specified climate target (typically, a given concentration of greenhouse gases) suggests that net mitigation costs increase, on average, by approximately 40 percent for each decade of delay. These costs are higher for more aggressive climate goals: each year of delay means more CO₂ emissions, so it becomes increasingly difficult, or even infeasible, to hit a climate target that is likely to yield only moderate temperature increases.

Second, climate policy can be thought of as “climate insurance” taken out against the most severe and irreversible potential consequences of climate change. Events such as the rapid melting of ice sheets and the consequent increase of global sea levels, or temperature increases on the higher end of the range of scientific uncertainty, could pose such severe economic consequences as reasonably to be thought of as climate catastrophes. Confronting the possibility of climate catastrophes means taking prudent steps now to reduce the future chances of the most severe consequences of climate change. The longer that action is postponed, the greater will be the concentration of CO₂ in the atmosphere and the greater is the risk. Just as businesses and individuals guard against severe financial risks by purchasing various forms of insurance, policymakers can take actions now that reduce the chances of triggering the most severe climate events. And, unlike conventional insurance policies, climate policy that serves as climate insurance is an investment that also leads to cleaner air, energy security, and benefits that are difficult to monetize like biological diversity.

I. Introduction

The changing climate and increasing atmospheric greenhouse gas (GHG) concentrations are projected to accelerate multiple threats, including more severe storms, droughts, and heat waves, further sea level rise, more frequent and severe storm surge damage, and acidification of the oceans (USGCRP 2014). Beyond the sorts of gradual changes we have already experienced, global warming raises additional threats of large-scale changes, either changes to the global climate system, such as the disappearance of late-summer Arctic sea ice and the melting of large glacial ice sheets, or ecosystem impacts of climate change, such as critical endangerment or extinction of a large number of species.

Emissions of GHGs such as carbon dioxide (CO₂) generate a cost that is borne by present and future generations, that is, by people other than those generating the emissions. These costs, or economic damages, include costs to health, costs from sea level rise, and damage from increasingly severe storms, droughts, and wildfires. These costs are not reflected in the price of those emissions. In economists' jargon, emitting CO₂ generates a negative externality and thus a market failure. Because the price of CO₂ emissions does not reflect its true costs, market forces alone are not able to solve the problem of climate change. As a result, without policy action, there will be more emissions and less investment in emissions-reducing technology than there would be if the price of emissions reflected their true costs.

This report examines the cost of delaying policy actions to stem climate change, and reaches two main conclusions. First, delaying action is costly. If a policy delay leads to higher ultimate CO₂ concentrations, then that delay produces persistent additional economic damages caused by higher temperatures, more acidic oceans, and other consequences of higher CO₂ concentrations. Moreover, if delay means that the policy, when implemented, must be more stringent to meet a given target, then it will be more costly.

Second, uncertainty about the most severe, irreversible consequences of climate change adds urgency to implementing climate policies *now* that reduce GHG emissions. In fact, climate policy can be seen as climate insurance taken out against the most damaging potential consequences of climate change—consequences so severe that these events are sometimes referred to as climate catastrophes. The possibility of climate catastrophes leads to taking prudent steps now to sharply reduce the chances that they occur.

The costs of inaction underscore the importance of taking meaningful steps today towards reducing carbon emissions. An example of such a step is the Environmental Protection Agency's (EPA) proposed rule (2014) to regulate carbon pollution from existing power plants. By adopting economically efficient mechanisms to reduce emissions over the coming years, this proposed rule would generate large positive net benefits, which EPA estimates to be in the range of \$27 - 50 billion annually in 2020 and \$49 - 84 billion in 2030. These benefits include benefits to health from reducing particulate emissions as well as benefits from reducing CO₂ emissions.

Delaying Climate Policies Increases Costs

Delaying climate policies avoids or reduces expenditures on new pollution control technologies in the near term. But this short-term advantage must be set against the disadvantages, which are the costs of delay. The costs of delay are driven by fundamental elements of climate science and economics. Because the lifetime of CO₂ in the atmosphere is very long, if a mitigation policy is delayed, it must take as its starting point a higher atmospheric concentration of CO₂. As a result, delayed mitigation can result in two types of cost, which we would experience in different proportions depending on subsequent policy choices.

First, if delay means an increase in the ultimate end-point concentration of CO₂, then delay will result in additional warming and additional economic damages resulting from climate change. As is discussed in Section II, economists who have studied the costs of climate change find that temperature increases of 2° Celsius above preindustrial levels or less are likely to result in aggregate economic damages that are a small fraction of GDP. This small net effect masks important differences in which some regions could benefit somewhat from this warming while other regions could experience net costs. But global temperatures have *already* risen nearly 1° above preindustrial levels, and it will require concerted effort to hold temperature increases to within the narrow range consistent with small costs.³ For temperature increases of 3° Celsius or more above preindustrial levels, the aggregate economic damages from climate change are expected to increase sharply.

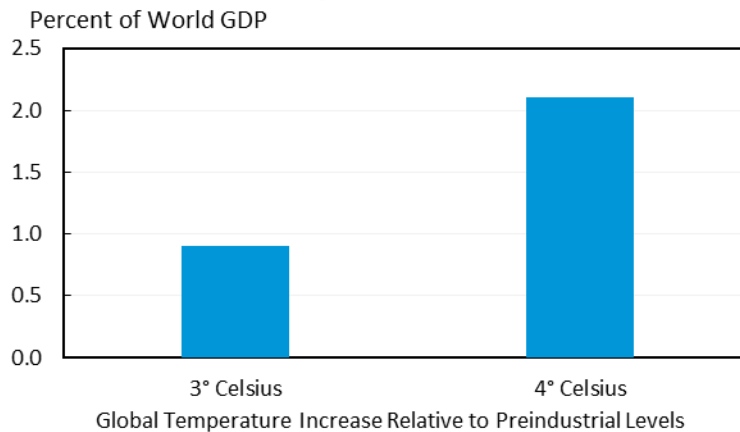
Delay that causes a climate target to be missed creates large estimated economic damages. For example, a calculation in Section II of this report, based on a leading climate model (the DICE model as reported in Nordhaus 2013), shows that if a delay causes the mean global temperature increase to stabilize at 3° Celsius above preindustrial levels, instead of 2°, that delay will induce annual additional damages of approximately 0.9 percent of global output, as shown in Figure 1.⁴ To put this percentage in perspective, 0.9 percent of estimated 2014 U.S. GDP is approximately \$150 billion.⁵ The next degree increase, from 3° to 4°, would incur greater *additional* annual costs of approximately 1.2 percent of global output. These costs are not one-time: they are incurred year after year because of the permanent damage caused by additional climate change resulting from the delay.

³ The Working Group III contribution to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (IPCC WG III AR5 2014) does not analyze scenarios producing temperatures in 2100 less than 1.5 Celsius above preindustrial, because this is considered so difficult to achieve.

⁴ Nordhaus (2013) stresses that these estimates “are subject to large uncertainties...because of the difficulty of estimating impacts in areas such as the value of lost species and damage to ecosystems.” (pp. 139-140).

⁵ These percentages apply to gross world output and the application of them to U.S. GDP is illustrative.

**Figure 1: Economic Damage from Temperature Increase
Beyond 2° Celsius**



Source: Nordhaus (2013) and CEA calculations

The second type of cost of delay is the increased cost of reducing emissions more sharply if, instead, the delayed policy is to achieve the same climate target as the non-delayed policy. Taking meaningful steps now sends a signal to the market that reduces long-run costs of meeting the target. Part of this signal is that new carbon-intensive polluting facilities will be seen as bad investments; this reduces the amount of locked-in high-carbon infrastructure that is expensive to replace. Second, taking steps now to reduce CO₂ emissions signals the value of developing new low- and zero-emissions technologies, so additional steps towards a zero-carbon future can be taken as policy action incentivizes the development of new technologies. For both reasons, the least-cost mitigation path to achieve a given concentration target typically starts with a relatively low price of carbon to send these signals to the market, and subsequently increases as new low-carbon technology becomes available.⁶

The research discussed in Section II of this report shows that any short run gains from delay tend to be outweighed by the additional costs arising from the need to adopt a more abrupt and stringent policy later.⁷ An analysis of the collective results from that research, described in more detail in Section II, suggests that the cost of hitting a specific climate target increases, on average, by approximately 40 percent for each decade of delay. These costs are higher for more aggressive climate goals: the longer the delay, the more difficult it becomes to hit a climate target. Furthermore, the research also finds that delay substantially decreases the chances that even concerted efforts in the future will hit the most aggressive climate targets.

⁶ The 2010 National Research Council, *Limiting the Magnitude of Future Climate Change*, also stressed the importance of acting now to implement mitigation policies as a way to reduce costs. The NRC emphasized the importance of technology development in holding down costs, including by providing clear signals to the private sector through predictable policies that support development of and investment in low-carbon technologies.

⁷ The IPCC WG III AR5 (2014) includes an extensive discussion of mitigation, including sectoral detail, potential for technological progress, and the timing of mitigation policies.

Although global action is essential to meet climate targets, unilateral steps both encourage broader action and benefit the United States. Climate change is a global problem, and it will require strong international leadership to secure cooperation among both developed and developing countries to solve it. America must help forge a truly global solution to this global challenge by galvanizing international action to significantly reduce emissions. By taking credible steps toward mitigation, the United States will also reap the benefits of early action, such as investing in low-carbon infrastructure now that will reduce the costs of reaching climate targets in the future.

Climate Policy as Climate Insurance

Individuals and businesses routinely purchase insurance to guard against various forms of risk such as fire, theft, or other loss. This logic of self-protection also applies to climate change. Much is known about the basic science of climate change: there is a scientific consensus that, because of anthropogenic emissions of CO₂ and other GHGs, global temperatures are increasing, sea levels are rising, and the world's oceans are becoming more acidic. These and other climate changes are expected to be harmful, on balance, to the world's natural and economic systems. Nevertheless, uncertainty remains about the magnitude and timing of these and other aspects of climate change, even if we assume that future climate policies are known in advance. For example, the Working Group I contribution to the IPCC's Fifth Assessment Report (IPCC WG I AR5 2013) provides a likely range of 1.5° to 4.5° Celsius for the equilibrium climate sensitivity, which is the long-run increase in global mean surface temperature that is caused by a sustained doubling of atmospheric CO₂ concentrations. The upper end of that range would imply severe climate impacts under current emissions trajectories, and current scientific knowledge indicates that values in excess of this range are also possible.⁸

An additional, related source of climate uncertainty is the possibility of irreversible, large-scale changes that have wide-ranging and severe consequences. These are sometimes called abrupt changes because they could occur extremely rapidly as measured in geologic time, and are also sometimes called climate catastrophes. We are already witnessing one of these events—the rapid trend towards disappearance of late-summer Arctic sea ice. A recent study from the National Research Council (NRC 2013) found that this strong trend toward decreasing sea-ice cover could have large effects on a variety of components of the Arctic ecosystem and could potentially alter large-scale atmospheric circulation and its variability. The NRC also found that another large-scale change has been occurring, which is the critical endangerment or loss of a significant percentage of marine and terrestrial species. Other events judged by the NRC to be likely in the more distant future (after 2100) include, for example, the possible rapid melting of the Western Antarctic ice and Greenland ice sheets and the potential thawing of Arctic permafrost and the consequent release of the potent GHG methane, which would accelerate global warming. These and other potential large-scale changes are irreversible on relevant time

⁸ It is important to note that, as a global average, the equilibrium climate sensitivity masks the expectation that temperature change will be higher over land than the oceans, and that there will be substantial regional variations in temperature increases. The equilibrium climate sensitivity describes a long-term effect and is only one component of determining near term warming due to the buildup of GHGs in the atmosphere.

scales—if an ice sheet melts, it cannot be reconstituted—and they could potentially have massive global consequences and costs. For many of these events, there is thought to be a “tipping point,” for example a temperature threshold, beyond which the transition to the new state becomes inevitable, but the values or locations of these tipping points are typically unknown.

Section III of this report examines the implications of these possible climate-related catastrophes for climate policy. Research on the economic and policy implications of such threats is relatively recent. As detailed in Section III, a conclusion that clearly emerges from this young but active literature is that the threat of a climate catastrophe, potentially triggered by crossing an unknown tipping point, implies erring on the side of prudence today. Accordingly, in a phrase used by Weitzman (2009, 2012), Pindyck (2011), and others, climate policy can be thought of as “climate insurance.” The logic here is that of risk management, in which one acts now to reduce the chances of worst-case outcomes in the future. Here, too, there is a cost to delay: the longer emission reductions are postponed, the greater are atmospheric concentrations of GHGs, and the greater is the risk arising from delay.

Other Costs of Delay and Benefits of Acting Now

An additional benefit of adopting meaningful mitigation policies now is that doing so sends a strong signal to the market to spur the investments that will reduce mitigation costs in the future. An argument sometimes made is that mitigation policies should be postponed until new low-carbon technologies become available. Indeed, ongoing technological progress has dramatically improved productivity and welfare in the United States because of vast inventions and process improvements in the private sector (see for example CEA 2014, Chapter 6). The private sector invests in research and development, and especially in process improvements, because those technological advances reap private rewards. But low-carbon technologies, and environmental technologies more generally, face a unique barrier: their benefits – the reduction in global impacts of climate change – accrue to everyone and not just to the developer or adopter of such technologies.⁹ Thus private sector investment in low-carbon technologies requires confidence that those investments, if successful, will pay off, that is, the private sector needs to have confidence that there will be a market for low-carbon technologies now and in the future. Public policies that set out a clear and ongoing mitigation path provide that confidence. Simply waiting for a technological solution, but not providing any reason for the private sector to create that solution, is not an effective policy. Although public financing of basic research is warranted because many of the benefits of basic research cannot be privately appropriated, many of the productivity improvements and cost reductions seen in new technologies come from incremental advances and process improvements that only arise through private-sector experience producing the product and learning-by-doing. These advances are protected through the patent system and as trade secrets, but those advances will only transpire if it is clear that they will have current and

⁹ Popp, Newell, and Jaffe (2010) provide a thorough review of the literature regarding technological change and the environment.

future value. In other words, policy action induces technological change.¹⁰ Although a full treatment of the literature on technological change is beyond the scope of this report, providing the private sector with the certainty needed to invest in low-carbon technologies and produce such technological change is a benefit of adopting meaningful mitigation policies now.

Finally, because this report examines the economic costs of delay, it focuses on actions or consequences that have a market price. But the total costs of climate change include much that does not trade in the market and to which it is difficult to assign a monetary value, such as the loss of habitat preservation, decreased value of ecosystem goods and services, and mass extinctions. Although some studies have attempted to quantify these costs, including all relevant climate impacts is infeasible. Accordingly, the monetized economic costs of delay analyzed in this report understate the true total cost of delaying action to mitigate climate change.

¹⁰ For example, Popp (2003) provides empirical evidence that Title IV of the 1990 Clean Air Act Amendments (CAAA) led to innovations that reduced the cost of the environmental technologies that reduced SO₂ emissions from coal-fired power plants. Other literature shows evidence linking environmental regulation more broadly to innovation (e.g., Popp 2006, Jaffe and Palmer 1997, Lanjouw and Mody 1996).

II. Costs from Delaying Policy Action

Delaying action on climate change can increase economic costs in two ways. First, if the delayed policy is no more stringent, it will miss the climate target of the original, non-delayed policy, resulting in atmospheric GHG concentrations that are permanently higher, thereby increasing the economic damages from climate change. Second, suppose a delayed policy alternatively strove to achieve the original climate target; if so, it would require a more stringent path to achieve that target. But this delayed, more stringent policy typically will result in additional mitigation costs by requiring more rapid adjustment later. In reality, delay might result in a mix of these two types of costs. The estimates of the costs of delay in this section draw on large bodies of research on these two types of costs. We first examine the economic damages from higher temperatures, then turn to the increased mitigation costs arising from delay.

Our focus here is on targets that limit GHG concentrations, both because this is what most of the “delay” literature considers and because concentration limits have been the focus of other assessments. These concentration targets are typically expressed as concentrations of CO₂-equivalent (CO₂e) GHGs, so they incorporate not just CO₂ concentrations but also methane and other GHGs. The CO₂e targets translate roughly into ranges of temperature changes as estimated by climate models and into the cumulative GHG emissions budgets discussed in some other climate literature. More stringent concentration targets decrease the odds that global average temperature exceeds 2°C above preindustrial levels by 2100. According to the IPCC WG III AR5 (2014), meeting a concentration target of 450 parts per million (ppm) CO₂e makes it “likely” (probability between 66 and 100 percent) that the temperature increase will be at most 2°C, relative to preindustrial levels, whereas stabilizing at a concentration level of 550 ppm CO₂e makes it “more unlikely than likely” (less than a 50 percent probability) that the temperature increase by 2100 will be limited to 2°C (IPCC WG III AR5 2014).¹¹

Increasing Damages if Delay Means Missing Climate Targets

If delay means that a climate target slips, then the ultimate GHG concentrations, temperatures, and other changes in global climate would be greater than without the delay.¹²

A growing body of work examines the costs that climate change imposes on specific aspects of economic activity. The IPCC WG II AR5 (2014) surveys this growing literature and summarizes the impacts of projected climate change by sector. Impacts include decreased agricultural production; coastal flooding, erosion, and submergence; increases in heat-related illness and other stresses due to extreme weather events; reduction in water availability and quality;

¹¹ IPCC WG III AR5 (2014, ch. 6) provides a further refinement of these probabilities, associating a concentration target of 450 ppm of CO₂e with an approximate 70-85 percent probability of maintaining temperature change below 2°C, and a concentration level of 550 CO₂e with an approximate 30-45 percent probability of maintaining temperature change below 2°C.

¹² For information on the impacts of climate change at various levels of warming see *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (NRC 2011).

displacement of people and increased risk of violent conflict; and species extinction and biodiversity loss. Although these impacts vary by region, and some impacts are not well-understood, evidence of these impacts has grown in recent years.¹³

A new class of empirical studies draw similar conclusions. Dell, Jones, and Olken (2013) review academic research that draws on historical variation in weather patterns to infer the effects of climate change on productivity, health, crime, political instability, and other social and economic outcomes. This approach complements physical science research by estimating the economic impacts of historical weather events that can be used to extrapolate to those expected in the future climate. The research finds evidence of economically meaningful impacts of climate change on a variety of outcomes. For example, when the temperature is greater than 100° Fahrenheit in the United States, labor supply in outdoor industries declines up to one hour per day relative to temperatures in the 76°-80° Fahrenheit range (Graff Zivin and Neidell 2014). Also in the United States, each additional day of extreme heat (exceeding 90° Fahrenheit) relative to a moderate day (50° to 59° Fahrenheit) increases the annual age-adjusted mortality rate by roughly 0.11 percent (Deschênes and Greenstone 2011).

These studies provide insights into the response of specific sectors or aspects of the economy to climate change. But because they focus on specific aspects of climate change, use different data sources, and use a variety of outcome measures, they do not provide direct estimates of the aggregate, or total, cost of climate change. Because estimating the total cost of climate change requires specifying future baseline economic and population trajectories, efforts to estimate the total cost of climate change typically rely on integrated assessment models (IAMs). IAMs are a class of economic and climate models that incorporate both climate and economic dynamics so that the climate responds to anthropogenic emissions and economic activity responds to the climate. In addition to projecting future climate variables and other economic variables, the IAMs estimate the total economic damages (and, in some cases, benefits) of climate change which includes impacts on agriculture, health, ecosystems services, productivity, heating and cooling demand, sea level rise, and adaptation.

Overall costs of climate change are substantial, according to IAMs. Nordhaus (2013) estimates global costs that increase with the rise in global average temperature, and Tol (2009, 2014) surveys various estimates. Two themes are common among these damage estimates. First, damage estimates remain uncertain, especially for large temperature increases. Second, the costs of climate change increase nonlinearly with the temperature change. Based on Nordhaus's (2013, Figure 22) net damage estimates, a 3° Celsius temperature increase above preindustrial levels, instead of 2°, results in additional damages of 0.9 percent of global output.¹⁴ To put this

¹³ The EPA's Climate Change Impacts and Risk Analysis project collects new research that estimates the potential damages of inaction and the benefits of GHG mitigation at national and regional scales for many important sectors, including human health, infrastructure, water resources, electricity demand and supply, ecosystems, agriculture, and forestry (Waldhoff et al. 2014).

¹⁴ Some studies estimate that small temperature increases have a net economic *benefit*, for instance due to increased agricultural production in regions with colder climates. However, projected temperature increases even

percentage in perspective, 0.9 percent of estimated 2014 U.S. GDP is approximately \$150 billion. The next degree increase, from 3° to 4°, would incur additional costs of 1.2 percent of global output. Moreover, these costs are not one-time, rather they recur year after year because of the permanent damage caused by increased climate change resulting from the delay. It should be stressed that these illustrative estimates are based on a single (albeit leading) model, and there is uncertainty associated with the aggregate monetized damage estimates from climate change; see for example the discussion in IPCC WG II AR5 (2014).

Increased Mitigation Costs from Delay

The second type of cost of delay arises if policy is delayed but still hits the climate target, for example stabilizing CO₂e concentrations at 550 ppm. Because a delay results in additional near-term accumulation of GHGs in the atmosphere, delay means that the policy, when implemented, must be more stringent to achieve the given long-term climate target. This additional stringency increases mitigation costs, relative to those that would be incurred under the least-cost path starting today.

This section reviews the recent literature on the additional mitigation costs of delay, under the assumption that both the original and delayed policy achieve a given climate target. We review 16 studies that compare 106 pairs of policy simulations based on integrated climate mitigation models (the studies are listed and briefly described in the Appendix). The simulations comprising each pair implement similar policies that lead to the same climate target (typically a concentration target but in some cases a temperature target) but differ in the timing of the policy implementation, nuanced in some cases by variation in when different countries adopt the policy. Because the climate target is the same for each scenario in the pair, the environmental and economic damages from climate change are approximately the same for each scenario. The additional cost of delaying implementation thus equals the difference in the mitigation costs in the two scenarios in each paired comparison. The studies reflect a broad array of climate targets, delayed timing scenarios, and modeling assumptions as discussed below. We focus on studies published in 2007 or later, including recent unpublished manuscripts.

In each case, a model computes the path of cost-effective mitigation policies, mitigation costs, and climate outcomes over time, constraining the emissions path so that the climate target is hit. Each path weighs technological progress in mitigation technology and other factors that encourage starting out slowly against the costs that arise if mitigation, delayed too long, must be undertaken rapidly. Because the models typically compute the policy in terms of a carbon price, the carbon price path computed by the model starts out relatively low and increases over the course of the policy. Thus a policy started today typically has a steadily increasing carbon price, whereas a delayed policy typically has a carbon price of zero until the start date, at which point it jumps to a higher initial level then increases more rapidly than the optimal immediate policy.

under immediate action fall in a range with a strong consensus that the costs of climate change exceed such benefits. The cost estimates presented here are net of any benefits expected to accrue.

The higher carbon prices after a delay typically lead to higher total costs than a policy that would impose the carbon price today.¹⁵

The IPCC WG III AR5 (2014) includes an overview of the literature on the cost of delayed action on climate change. They cite simulation studies showing that delay is costly, both when all countries delay action and when there is partial delay, with some countries delaying acting alone until there is a more coordinated international effort. The present report expands on that overview by further analyzing the findings of the studies considered by the IPCC report as well as additional studies. Like the IPCC report, we find broad agreement across the scenario pairs examined that delayed policy action is more costly compared to immediate action conditional on a particular climate target. This finding is consistent across a range of climate targets, policy participants, and modeling assumptions. The vast majority of studies estimate that delayed action incurs greater mitigation costs compared to immediate action. Furthermore, some models used in the research predict that the most stringent climate targets are feasible only if immediate action is taken under full participation. One implication is that considering only comparisons with numerical cost estimates may understate the true costs of delay, as failing to reach a climate target means incurring the costs from the associated climate change.

The costs of delay in these studies depend on a number of factors, including the length of delay, the climate target, modeling assumptions, future baseline emissions, future mitigation technology, delay scenarios, the participants implementing the policy, and geographic location. More aggressive targets are more costly to achieve, and meeting them is predicted to be particularly costly, if not infeasible, if action is delayed. Similarly, international coordination in policy action reduces mitigation costs, and the cost of delay depends on which countries participate in the policy, as well as the length of delay.

¹⁵ Some models explicitly identify the carbon price path that minimizes total social costs. These optimization models always find equal or greater costs for scenarios with a delay constraint. Other models forecast carbon prices that result in the climate target but do not demand that the path results in minimal cost. These latter models can predict that delay reduces costs, and a small number of comparisons we review report negative delay costs.

THE ROLE OF TECHNOLOGICAL PROGRESS IN COST ESTIMATES

Assumptions about energy technology play an important role in estimating mitigation costs. For example, many models assume that carbon capture and storage (CCS) will enable point sources of emission to capture the bulk of carbon emissions and store them with minimal leakage into the atmosphere over a long period. Some comparisons also assume that CCS will combine with large-scale bio-energy (“bio-CCS”), effectively generating “negative emissions” since biological fuels extract atmospheric carbon during growth. Such technology could facilitate reaching a long-term atmospheric concentration target despite relatively modest near-term mitigation efforts. However, the IPCC warns that “There is only limited evidence on the potential for large-scale deployment of [bio-CCS], large-scale afforestation, and other [CO₂ removal] technologies and methods” (IPCC WG III AR5 2014). In addition, models must also specify the cost and timing of availability of such technology, potentially creating further variation in mitigation cost estimates.

The potential importance of technology, especially bio-CCS, is manifested in differences across models. Clarke et al. (2009) present delay cost estimates for 10 models simulating a 550 ppm CO₂ equivalent target by 2100 allowing for overshoot. The three models that assume bio-CCS availability estimate global present values of the cost of delay ranging from \$1.4 trillion to \$4.7 trillion. Among the seven models without bio-CCS, four predict higher delay costs, one predicts that the concentration target was infeasible under a delay, and two predict lower delay costs. The importance of bio-CCS is even clearer with a more stringent target. For example, two of the three models with bio-CCS find that a 450 ppm CO₂ equivalent target is feasible under a delay scenario, while none of the seven models without bio-CCS find the stringent target to be feasible.

The Department of Energy sponsors ongoing research on CCS for coal-fired power plants. As part of its nearly \$6 billion commitment to clean coal technology, the Administration, partnered with industry, has already invested in four commercial-scale and 24 industrial-scale CCS projects that together will store more than 15 million metric tons of CO₂ per year.

An important determinant of costs is the role of technological progress and the availability of mitigation technologies (see the box). The models typically assume technological progress in mitigation technology, which means that the cost of reducing emissions declines over time as energy technologies improve. As a result, it is cost-effective to start with a relatively less stringent policy, then increase stringency over time, and the models typically build in this cost-effective tradeoff. However, most models still find that immediate initiation of a less stringent policy followed by increasing stringency incurs lower costs than delaying policy entirely and then increasing stringency more rapidly.

We begin by characterizing the primary findings in the literature broadly, discussing the estimates of delay costs and how the costs vary based on key parameters of the policy scenarios; additional details can be found in the Appendix. We then turn to a statistical analysis of all the available

delay cost estimates that we could gather in a standardized form, that is, we conduct a meta-analysis of the literature on delay cost estimates.

Effect on Costs of Climate Targets, Length of Delay, and International Coordination

Climate Targets

Researchers estimate a range of climate and economic impacts from a given concentration of GHGs and find that delaying action is much costlier for more stringent targets. Two recent major modeling simulation projects conducted by the Energy Modeling Forum (Clarke et al. 2009) and by AMPERE (Riahi et al. 2014) consider the economic costs of delaying policies to reach a range of CO₂e concentration targets from 450 to 650 ppm in 2100. In the Energy Modeling Forum simulations in Clarke et al. (2009), the median additional cost (global present value) for a 20-year delay is estimated to be \$0.7 trillion for 650 ppm CO₂e but a substantially greater \$4.7 trillion for 550 ppm CO₂e. Many of the models in these studies suggest that delay causes a target of 450 ppm CO₂e to be much more costly to achieve, or possibly even infeasible.

Length of Delay

The longer the delay, the greater the cumulative emissions before action begins and the shorter the available time to meet a given target. Several recent studies examine the cost implications of delayed climate action and find that even a short delay can add substantial costs to meeting a stringent concentration target, or even make the target impossible to meet. For example, Luderer et al. (2012) find that delay from 2010 to 2020 to stabilize CO₂ concentration levels at 450 ppm by 2100 raises mitigation cost by 50 to 700 percent.¹⁶ Furthermore, Luderer et al. find that delay until 2030 renders the 450 ppm target infeasible. Edmonds et al. (2008) find that additional mitigation costs of delay by newly developed and developing countries are substantial. In fact, they find that stabilizing CO₂ concentrations at 450 ppm even for a relatively short delay from 2012 to 2020 increases costs by 28 percent over the idealized case, and a delay to 2035 increased costs by more than 250 percent.

International Coordination

Meeting stringent climate targets with action from only one country or a small group of countries is difficult or impossible, making international coordination of policies essential. Recent research shows, however, that even if a delay in international mitigation efforts occurs, unilateral or fragmented action reduces the costs of delay: although immediate coordinated international action is the least costly approach, unilateral action is less costly than doing nothing.¹⁷ More specifically, Jakob et al. (2012) consider a 10-year delay of mitigation efforts to reach a 450 ppm CO₂ target by 2100 and find that global mitigation costs increase by 43 to 700 percent if all countries begin mitigation efforts in 2020 rather than 2010. However, early action in 2010 by more developed countries reduces this increase to 29 to 300 percent. In a similar scenario,

¹⁶ We present a range of cost estimates which comes from the three IAMs – ReMIND-R, WITCH and IMACLIM-R – used by Luderer et al. (2012). These scenarios also allow temporary overshoot of the target.

¹⁷ Waldhoff and Fawcett (2011) find that early mitigation action by industrialized economies significantly reduces the likelihood of large temperature changes in 2100 while also increasing the likelihood of lower temperature changes, relative to a no policy scenario.

Luderer et al. (2012) find that costs increase by 50 to 700 percent with global delay from 2010 to 2020, however if the industrialized countries begin mitigation efforts unilaterally in 2010 (and are joined by all countries in 2020), the estimated cost increases range from zero to about 200 percent. Luderer et al. (2013) and Riahi et al. (2014) find that costs of delay are smaller when fewer countries delay mitigation efforts, or when short-term actions during the delay are more aggressive.

Jakob et al. (2012) find it is in the best interest of the European Union to begin climate action in 2010 rather than delaying action with all other countries until 2020. They also estimate that the cost increase to the United States from delaying climate action with all other countries until 2020 is from 28 to 225 percent, relative to acting early along with other industrialized economies.¹⁸ McKibbin, Morris, and Wilcoxon (2014) consider the impact that a delay in imposing a unilateral price of carbon would have on economic outcomes in the United States including GDP, investment, consumption and employment. They find that although unilateral mitigation efforts do incur costs, delay is costlier.

Summary: Quantifying Patterns across the Studies

We now turn to a quantitative summary and assessment, or meta-analysis, of the studies discussed above.¹⁹ The data set for this analysis consists of the results on all available numerical estimates of the average or total cost of delayed action from our literature search. Each estimate is a paired comparison of a delay scenario and its companion scenario without delay. To make results comparable across studies, we convert the delay cost estimates (presented in the original studies variously as present values of dollars, percent of consumption, or percent of GDP) to percent change in costs as a result of delay.²⁰ We capture variation across study and experimental designs using variables that encode the length of the delay in years; the target CO₂e concentration; whether only the relatively more-developed countries act immediately (partial delay); the discount rate used to calculate costs; and the model used for the simulation.²¹ All comparisons consider policies and outcomes measured approximately through the end of the century. To reduce the effect of outliers, the primary regression analysis only uses results with less than a 400 percent increase in costs (alternative methods of handling the outliers are

¹⁸ Note that the IMACLIM model finds that U.S. mitigation declines to the point in which they are slightly negative (i.e. net gains compared to business-as-usual).

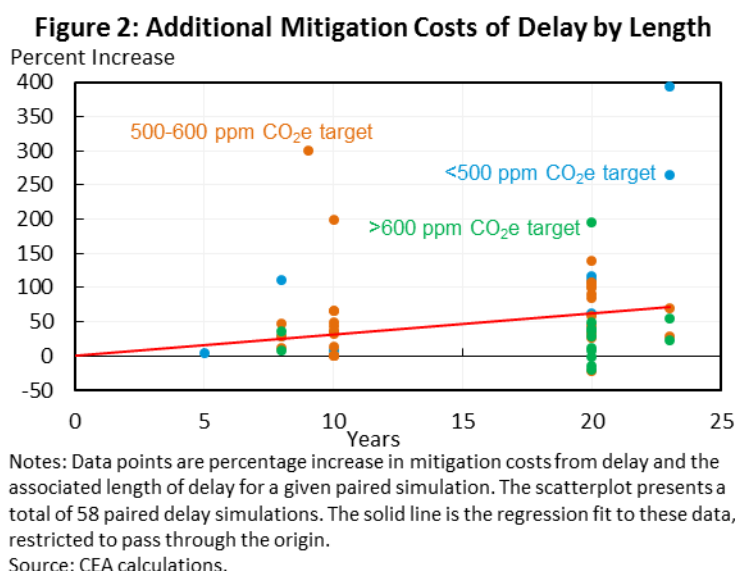
¹⁹ A study of the results of other studies is referred to as a meta-analysis, and there is a rich body of statistical tools for meta-analysis, see for example Borenstein et al. (2009).

²⁰ For example, if in some paired comparison delay increased mitigation costs from 0.20 percent of GDP to 0.30 percent of GDP, the cost increase would be 50 percent. Comparisons for which the studies provided insufficient information to calculate the percentage increase in costs (including all comparisons from Riahi et al. 2014) are excluded. Also excluded are comparisons that report only the market price of carbon emissions at the end of the simulation, which is not necessarily proportional to total mitigation costs.

²¹ When measuring delay length for policies with multiple stages of implementation, we count the delay as ending at the start of any new participation in mitigation by any party after the start of the simulation. We also exclude scenarios with delays exceeding 30 years. When other climate targets were provided (e.g., CO₂ concentration or global average temperature increase), the corresponding CO₂e concentration levels are estimated using conversions from IPCC WG III AR5 (2014).

discussed below as sensitivity checks), and only includes paired comparisons for which both the primary and delayed policies are feasible (i.e. the model was able to solve for both cases).²² The dataset contains a total of 106 observations (paired comparisons), with 58 included in the primary analysis. All observations in the data set are weighted equally.

Analysis of these data suggests two main conclusions, both consistent with findings from specific papers in the underlying literature. The first is that, looking across studies, costs increase with the length of the delay. Figure 2 shows the delay costs as a function of the delay time. Although there is considerable variability in costs for a given delay length because of variations across models and experiments, there is an overall pattern of costs increasing with delay.



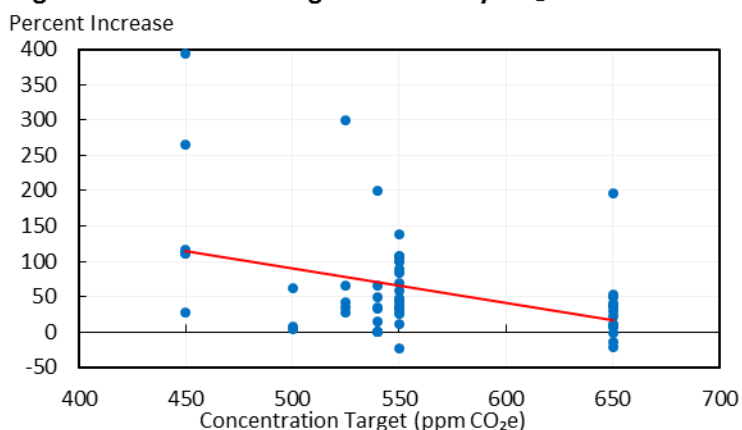
For example, of the 14 paired simulations with 10 years of delay (these are represented by the points in Figure 2 with 10 years of delay), the average delay cost is 39 percent. The regression line shown in Figure 2 estimates an average cost of delay per year using all 58 paired experiments under the assumption of a constant increasing delay cost per year (and, by definition, no cost if there is no delay), and this estimate is 37 percent per decade. This analysis ignores possible confounding factors, such as longer delays being associated with less stringent targets, and the multiple regression analysis presented below controls for such confounding factors.

The second conclusion is that the more ambitious the climate target, the greater are the costs of delay. This can be seen in Figure 3, in which the lowest (most stringent) concentration targets tend to have the highest cost estimates. In fact, close inspection of Figure 2 reveals a related pattern: the relationship between delay length and additional costs is steeper for the points representing CO₂e targets of 500 ppm or less than for those in the other two ranges. That is, costs

²² In the event that a model estimates a cost for a first-best scenario but determines the corresponding delay scenario to be infeasible, the comparison is coded as having costs exceeding 400 percent. In addition, one comparison from Clarke et al. (2009) is excluded because a negative baseline cost precludes the calculation of a percent increase.

of delay are particularly high for scenarios with the most stringent target and the longest delay lengths.

Figure 3: Additional Mitigation Costs by CO₂ Concentration



Notes: Data points are percentage increase in mitigation costs from delay and the associated CO₂ concentration target for a given paired simulation. The scatterplot presents a total of 58 paired delay simulations. The solid line is the regression line fit to these data.

Table 1 presents the results of multiple regression analysis that summarizes how various factors affect predictions from the included studies, holding constant the other variables included in the regression. The dependent variable is the cost of delay, measured as the percentage increase relative to the comparable no-delay scenario, and the length of delay is measured in decades. Specifications (1) and (2) correspond to Figures 2 and 3, respectively. Each subsequent specification includes the length of the delay in years, an indicator variable for a partial delay scenario, and the target CO₂e concentration. In addition to the coefficients shown, specification (4) includes model fixed effects, which control for systematic differences across models, and each specification other than column (1) includes an intercept.

The results in Table 1 quantify the two main findings mentioned above. The coefficients in column (3) indicate that, looking across these studies, a one decade increase in delay length is on average associated with a 41 percent increase in mitigation cost relative to the no-delay scenario. This regression does not control for possible differences in baseline costs across the different models, however, so column (4) reports a variant that includes an additional set of binary variables indicating the model used (“model fixed effects”). Including model fixed effects increases the delay cost to 56 percent per decade. When the cost of a delay is estimated separately for different concentration target bins (column (5)), delay is more costly the more ambitious is the concentration target. But even for the least ambitious target – a CO₂e concentration exceeding 600 ppm – delay is estimated to increase costs by approximately 24 percent per decade. Because of the relatively small number of cases (58 paired comparisons), which are further reduced when delay is estimated within target bins, the standard errors are large, especially for the least ambitious scenarios, so for an overall estimate of the delay cost we do not differentiate between the different targets. While the regression in column (4) desirably controls for differences across models, other (unreported) specifications that handle

the outliers in different ways and include other control variables give per-decade delay estimates both larger and smaller than the regression in column (3).²³ We therefore adopt the estimate in regression (3) of 41 percent per decade as the overall annual estimate of delay costs.

One caveat concerning this analysis is that it only considers cases in which model solutions exist. The omitted, infeasible cases tend to be ones with ambitious targets that cannot be met when there is long delay, given the model's technology assumptions. For this reason, omitting these cases arguably understates the costs of delay reported in Table 1.²⁴ Additionally, we note that estimates of the effect of a partial delay (when some developed nations act now and other nations delay action) are imprecisely estimated, perhaps reflecting the heterogeneity of partial delay scenarios examined in the studies.

²³ The results in Table 1 are generally robust to using a variety of other specifications and regression methods, including: using the percent decrease from the delay case, instead of the percent increase from the no-delay case, as the dependent variable as an alternative way to handle outliers; using median regression, also as an alternative way to handle outliers; and including the discount factor as additional explanation of variation in the cost of delay, but this coefficient is never statistically significant. These regressions use linear compounding, not exponential, because the focus is on the per-decade delay cost not the annual delay cost. An alternative approach is to specify the dependent variable in logarithms (although this eliminates the negative estimates), and doing so yields generally similar results after compounding to those in Table 1.

²⁴ An alternative approach to omitting the infeasible-solution observations is to treat their values as censored at some level. Accordingly, the regressions in Table 1 were re-estimated using tobit regression, for which values exceeding 400 percent (including the non-solution cases) are treated as censored. As expected, the estimated costs of delay per year estimated by tobit regression exceed the ordinary least squares estimates. A linear probability model (not shown) indicates that scenarios with longer delay and more stringent targets are more likely to have delay cost increases exceeding 400 percent (including non-solution cases). The assumption of bio-CCS technology has no statistically significant correlation with delay cost increase in a censored regression but is associated with a significantly lower probability of delay cost increases exceeding 400 percent.

Table 1: Increased Mitigation Costs Resulting from a Delay, Given a Specified Climate Target: Regression Results

	(1)	(2)	(3)	(4)	(5)
Delay (decades)	37.3*** (5.9)		41.1** (17.0)	56.3*** (18.2)	
Delay (decades) x ppm CO ₂ e≤500					66.7** (27.1)
Delay (decades) x 500<ppm CO ₂ e≤600					24.9 (18.5)
Delay (decades) x ppm CO ₂ e>600					24.1 (33.9)
Partial delay			8.3 (26.0)	-20.0 (27.8)	14.8 (25.7)
Target CO ₂ e concentration		-0.49*** (0.16)	-0.61*** (0.16)	-0.61*** (0.15)	-0.30 (0.49)
Model fixed effects?	No	No	No	Yes	No
Observations	58	58	58	58	58
R-squared	0.41	0.15	0.24	0.53	0.30

Notes: The table presents ordinary least squares regression coefficients, with each column representing a different regression. For each, the dependent variable is the percent increase in cost from a scenario involving no delay to a scenario involving a delay. Each observation is a comparison of a pair of scenarios with the same climate target, for a total of 58 observations. The regressors represent some of the variables that characterize each paired comparison: the simulated delay, the delay interacted with the concentration target (binned), whether only some countries delayed (partial delay), and the target concentration. The appendix lists all studies from which the data were drawn. The specification in column (1) does not include a constant.

Significant at the: *10% **5% ***1% significance level.

Source: CEA calculations on results from studies listed in appendix.

III. Climate Policy as Climate Insurance

As discussed in the 2013 NRC report, *Abrupt Impacts of Climate Change: Anticipating Surprises*, the Earth's climate history suggests the existence of "tipping points," that is, thresholds beyond which major changes occur that may be self-reinforcing and are likely to be irreversible over relevant time scales. Some of these changes, such as the rapid decline in late-summer Arctic sea ice, are already under way. Others represent potential events for which a tipping point likely exists, but cannot at the present be located. For example, there is new evidence that we might already have crossed a previously unrecognized tipping point concerning the destabilization of the West Antarctic Ice Sheet (Joughin, Smith, and Medley 2014 and Rignot et. al. 2014). A tipping point that is unknown, but thought unlikely to be reached in this century, is the release of methane from thawing Arctic permafrost, which could reinforce the greenhouse effect and spur additional warming and exacerbate climate change. Tipping points can also be crossed by slower climate changes that exceed a threshold at which there is a large-scale change in a biological system, such as the rapid extinction of species. Such impacts could pose such severe consequences for societies and economies that they are sometimes called potential climate catastrophes.

This section examines the implications of these potentially severe outcomes for climate policy, a topic that has been the focus of considerable recent research in the economics literature. The main conclusion emerging from this growing body of work is that the potential of these events to have large-scale impacts has important implications for climate policy. Because the probability of a climate catastrophe increases as GHG emissions rise, missing climate targets because of postponed policies increases risks. Uncertainty about the likelihood and consequences of potential climate catastrophes adds further urgency to implementing policies now to reduce GHG emissions.

Tail Risk Uncertainty and Possible Large-Scale Changes

Were some of these large-scale events to occur, they would have severe consequences and would effectively be irreversible. Because these events are thought to be relatively unlikely, at least in the near term – that is, they occur in the "tail" of the distribution – but would have severe consequences, they are sometimes referred to as "tail risk" events. Because these tail risk events are outside the range of modern human experience, uncertainty surrounds both the science of their dynamics and the economics of their consequences.

Because many of these events are triggered by warming, their likelihood depends in part on the equilibrium climate sensitivity. The IPCC WG I AR5 (2013) provides a likely range of 1.5° to 4.5° Celsius for the equilibrium climate sensitivity. However, considerably larger values cannot be ruled out and are more likely than lower values (i.e. the probability distribution is skewed towards higher values). Combinations of high climate sensitivity and high GHG emissions can result in extremely large end-of-century temperature changes. For example, the IPCC WG III AR5 (2014) cites a high-end projected warming of 7.8° Celsius by 2100, relative to 1900-1950.

A second way to express this risk is to focus on specific large-scale changes in Earth or biological systems that could be triggered and locked in by GHG concentrations rising beyond a certain point. At higher climate sensitivities, the larger temperature response to atmospheric GHG concentrations would make it even more likely that we would cross temperature-related tipping points in the climate system. The potential for additional releases of methane, a potent GHG, from thawing permafrost, thus creating a positive feedback to further increase temperatures, is an example of such a tail risk event. Higher carbon dioxide concentrations in the atmosphere, by increasing the acidity of the oceans, could also trigger and lock in permanent changes to ocean ecosystems, such as diminished coral reef-building, which decreases biodiversity supported on reefs and decreases the breakwater effects that protect shorelines. The probability of significant negative effects from ocean acidification can be increased by other stressors such as higher temperatures and overfishing.

The box summarizes some of these potential large-scale events, which are sometimes also referred to as “abrupt” because they occur in a very brief period of geological time. These events are sufficiently large-scale they have the potential for severely disrupting ecosystems and human societies, and thus are sometimes referred to as catastrophic outcomes.

ABRUPT IMPACTS OF CLIMATE CHANGE: ANTICIPATING SURPRISES

The National Research Council's 2013 report, *Abrupt Impacts of Climate Change: Anticipating Surprises*, discusses a number of abrupt climate changes with potentially severe consequences. These events include:

- **Late-summer Arctic sea ice disappearance:** Strong trends of accelerating late-summer sea ice loss have been observed in the Arctic. The melting of Arctic sea ice comprises a positive feedback loop, as less ice means more sunlight will be absorbed into the dark ocean, causing further warming.
- **Sea level rise (SLR) from destabilization of West Antarctic ice sheets (WAIS):** The WAIS represents a potential SLR of 3-4 meters as well as coastal inundation and stronger storm surges. Much remains unknown of the physical processes at the ice-ocean frontier. However, two recent studies (Joughin, Smith, and Medley 2014, Rignot et. al. 2014) report evidence that irreversible WAIS destabilization has already started.
- **Sea level rise from other ice sheets melting:** Losing all other ice sheets, including Greenland, may cause SLR of up to 60 meters as well as coastal inundation and stronger storm surges. Melting of the Greenland ice sheet alone may induce SLR of 7m, but it is not expected to destabilize rapidly within this century.
- **Disruption to Atlantic Meridional Overturning Circulation (AMOC):** Potential disruptions to the AMOC may disrupt local marine ecosystems and shift tropical rain belts southward. Although current models do not indicate that an abrupt shift in the AMOC is likely within the century, the deep ocean remains understudied with respect to measures necessary for AMOC calculations.
- **Decrease in ocean oxygen:** As the solubility of gases decrease with rising temperature, a warming of the ocean will decrease the oxygen content in the surface ocean and expand existing Oxygen Minimum Zones. This will pose a threat to aerobic marine life as well as release nitrous oxide—a potent GHG—as a byproduct of microbial processes. The NRC study assesses a moderate likelihood of an abrupt increase in oxygen minimum zones in this century.
- **Increasing release of carbon stores in soils and permafrost:** Northern permafrost contains enough carbon to trigger a positive feedback response to warming temperatures. With an estimated stock of 1700-1800 Gt, the permafrost carbon stock could amplify considerably human-induced climate change. Small trends in soil carbon releases have been already observed.
- **Increasing release of methane from ocean methane hydrates:** This is a particularly potent long-term risk due to hydrate deposits through changes in ocean water temperature; the likely timescale for the physical processes involved spans centuries, however, and there is low risk this century.

- **Rapid state changes in ecosystems, species range shifts, and species boundary changes:** Research shows that climate change is an important component of abrupt ecosystem state-changes, with a prominent example being the Sahel region of Africa. Such state-changes from forests to savanna, from savanna to grassland, et cetera, will cause extensive habitat loss to animal species and threaten food and water supplies. The NRC study assesses moderate risk during this century and high risk afterwards.
- **Increases in extinctions of marine and terrestrial species:** Abrupt climate impacts include extensive extinctions of marine and terrestrial species; examples such as the destruction of coral reef ecosystems are already underway. Numerous land mammal, bird, and amphibian species are expected to become extinct with a high probability within the next one or two centuries.

Implications of Tail Risk

An implication of the theory of decision-making under uncertainty is that the risks posed by irreversible catastrophic events can be substantial enough to influence or even dominate decisions.

Weitzman's Dismal Theorem

Over the past few years, economists have examined the implications of decision-making under uncertainty for climate change policy. In a particularly influential treatment, Weitzman (2009) proposes his so-called “Dismal Theorem,” which provides a set of assumptions under which the current generation would be willing to bear very large (in fact, arbitrarily large) costs to avoid a future event with widespread, large-scale costs. The intuition behind Weitzman’s mathematical result rests with the basic insight that because individuals are risk-averse, they prefer to buy health, home, and auto insurance than to take their chances of a major financial loss. Similarly, if major climate events have the potential to reduce aggregate consumption by a large amount, society will be better off if it can take out “climate insurance” by paying mitigation costs now that will reduce the odds of a large-scale—in Weitzman’s (2009) word, catastrophic—drop in consumption later.²⁵

²⁵ This logic has its basis in expected utility theory. Because individuals are risk averse, each additional dollar of consumption provides less value, or utility, to individuals than the previous dollar. To avoid this major loss, an individual will buy home insurance. That insurance is provided by the market because an insurance company can offer home insurance to many homeowners in different regions of the country, and through diversification the company will on average have many homeowners paying premiums and a few collecting insurance, so diversification allows the company to run a relatively low-risk business. But risks from severe climate change are not diversifiable because their enormous costs would impact the global economy. Consequently, as long as there is a non-negligible probability of a large drop in consumption, and therefore a very large drop in utility, arising from a large-scale loss in consumption, society today should be willing to pay a substantial amount if doing so would avoid that loss.

Weitzman's (2009) dismal theorem has spurred a substantial amount of research on the economics of what this literature often refers to as climate catastrophes. A number of authors (e.g. Newbold and Daigneault 2009, Ackerman et al. 2010, Pindyck 2011, 2013, Nordhaus 2011, 2012, Litterman 2013, Millner 2013), including Weitzman (2011, 2014), stress that although the strong version of Weitzman's (2009) result—that society would be willing to pay an arbitrarily large amount to avoid future large-scale economic losses—depends on specific mathematical assumptions, the general principle of taking action to prevent such events does not. The basic insight is that, just as the sufficiently high threat of a fire justifies purchasing homeowners insurance, the threat of large-scale losses from climate change justifies purchasing “climate insurance” in the form of mitigation policies now (Pindyck 2011), and that taking actions today could help to avoid worst-case outcomes (Hwang, Tol, and Hofkes 2013). According to this line of thinking, the difficulty of assessing the probabilities of such large-scale losses or the location of tipping points does not change the basic conclusion that, because their potential costs are so overwhelming, the threat of very large losses due to climate change warrants implementing mitigation policies now.

Several recent studies have started down the road of quantifying the implications of the precautionary motive for climate policy. One approach is to build the effects of large-scale changes into IAMs, either by modeling the different risks explicitly or by simulation using heavy-tailed distributions for key parameters such as the equilibrium climate sensitivity or parameters of the economic damage function. Research along these lines includes Ackerman, Stanton, and Bueno (2013), Pycroft et al. (2011), Dietz (2011), Ceronsky et al. (2011), and Link and Tol (2011). Another approach is to focus on valuation of the extreme risks themselves outside an IAM, for example as examined by Pindyck (2012) and van der Ploeg and de Zeeuw (2013). Kopits, Marten, and Wolverton (2013) review some of the tail risk literature and literature on large-scale Earth system changes, and suggest steps forward for incorporating such events in IAMs, identifying ways in which the modeling could be improved even within current IAM frameworks and where additional work is needed. One of the challenges in assessing these large-scale events is that some of the most extreme events could occur in the distant future, and valuing consumption losses beyond this century raises additional uncertainty about intervening economic growth rates and questions about how to discount the distant future.²⁶ The literature is robust in showing that the potential for such events could have important climate policy implications, however, the scientific community has yet to derive robust quantitative policy recommendations based on a detailed analyses of the link between possible large-scale Earth system changes and their economic consequences.

Implications of Uncertainty about Tipping Points

Although research that embeds tipping points into climate models is young, one qualitative conclusion is that the prospect of a potential tipping point with unknown location enhances the precautionary motive for climate policy (Baranzini, Chesney, and Morisset 2003, Brozovic and Schlenker 2011, Cai, Judd, and Lontzek 2013, Lemoine and Traeger 2012, Barro 2013, van der

²⁶ For various perspectives on the challenges of evaluating long-term climate risks, see Dasgupta (2008), Barro (2013), Ackerman, Stanton, and Bueno (2013), Roe and Bauman (2013), and Weitzman (2013).

Ploeg 2014). To develop the intuition, first suppose that the tipping point is a known temperature increase, say 3° Celsius above preindustrial levels, and that the economic consequences of crossing the tipping point are severe, and temporarily put aside other reasons for reducing carbon emissions. Under these assumptions climate policy would allow temperature to rise, stopping just short of the 3° increase. In contrast, now suppose that the tipping point is unknown and that its estimated mean is 3°, but that it could be less or more with equal probability. In this case, the policy that stops just short of 3° warming runs a large risk of crossing the true tipping point. Because that mistake would be very costly, the uncertainty about the tipping point generally leads to a policy that is more stringent today than it would be absent uncertainty. To the extent that delayed implementation means higher long-run CO₂ concentrations, then the risks of hitting a tipping point increase with delay.

As a simplification, the above description assumes away other costs of climate change that increase smoothly with temperature, as well as the reality that important tipping points in biological systems could be crossed by small gradual changes in temperatures, so as to focus on the consequences of uncertainty about large-scale temperature changes. When the two sets of costs are combined, the presence of potential large-scale changes increases the benefits of mitigation policies, and the presence of uncertainty about tipping points that would produce abrupt changes increases those benefits further.²⁷ Cai, Judd, and Lontzek (2013) use a dynamic stochastic general equilibrium version of DICE model that is modified to include multiple tipping points with unknown (random) locations. To avoid the Weitzman “infinities” problem, they focus on tipping events with economic consequences that are large (5 or 10 percent of global GDP) but fall short of global economic collapses. They conclude that the possibility of future tipping points increases the optimal carbon price today: in their benchmark case, the optimal pre-tipping carbon price more than doubles, relative to having no tipping point dynamics. Similarly, Lemoine and Traeger (2012) embed unknown tipping points in the DICE model and estimate that the optimal carbon price increases by 45 percent as a result. In complementary work, Barro (2013) considers a simplified model in which the only benefits of reducing carbon emissions come from reducing the probability of potential climate catastrophes, and finds that this channel alone can justify investment in reducing GHG pollution of one percent of GDP or more, beyond what would normally occur in the market absent climate policy.

²⁷ Cai, Judd, and Lontzek (2013) provide a stark example of this dynamic. Their analysis, which is undertaken using a modified version of Nordhaus’s (2008) DICE-2007 model, includes both the usual reasons for emissions mitigation (damages that increase smoothly with temperature) and the possibility of a tipping point at an uncertain future temperature which results in a jump in damages.

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Appendix: Literature on Delay Costs

This appendix lists the studies reviewed Section II and used in the meta-analysis, and briefly describes the scenarios they analyzed.

The EMF22 project engaged ten leading integrated assessment models to analyze the climate and economic consequences of delay scenarios. The EMF22 studies consist of Loulou, Labriet, and Kanudia (2009), Tol (2009), Gurney, Ahammad, and Ford (2009), van Vliet, den Elzen, and van Vuuren (2009), Blanford, Richels, and Rutherford (2009), Krey and Riahi (2009), Calvin et al. (2009a, 2009b), Russ and van Ierland (2009), and Bosetti, Carraro, and Tavoni (2009), with Clarke et al. (2009) providing an overview of the project.²⁸ Among other objectives, each study estimates the mitigation costs associated with five climate targets under both an immediate action scenario and a harmonized delay scenario. The targets are 450, 550, and 650 ppm CO₂e in 2100, and the models consider the first two targets alternatively allowing or prohibiting an overshoot before 2100.²⁹ In the delay scenario, only more developed countries (minus Russia) begin mitigation immediately in 2012 in a coordinated fashion (i.e., with the same carbon pricing), with some countries delaying action until 2030, and remaining countries delay action until 2050. These scenarios enable calculating the additional mitigation costs associated with delay for each concentration target.

The AMPERE project engaged nine modeling teams to analyze the climate and economic consequences of global emissions following the proposed policy stringency of the national pledges from the Copenhagen Accord and Cancún Agreements to 2030. (The AMPERE scenarios were not included in the meta-analysis in Section II because Riahi et al. (2014) did not provide sufficient information to calculate the percent increase in mitigation costs for each delay scenario.) One of the questions addressed by this project is the economic costs of delaying policies to reach CO₂e concentration targets of 450 and 550 ppm in 2100 (Riahi et al. 2014). Eight models simulate pairs of policy scenarios reaching each target. One simulation in each pair assumes that all countries act immediately in a coordinated fashion (i.e., with the same carbon pricing), while the other simulation assumes that all countries follow the less stringent emissions commitments made during the Copenhagen Accord and Cancun Agreements until 2030, when coordinated international action begins.

The meta-analysis includes the following studies not associated with either AMPERE or EMF22: Jakob et al. (2012); Luderer et al. (2012, 2013); Edmonds et al. (2008); Richels et al. (2007), and Bosetti et al. (2009). Jakob et al. (2012) consider a 10-year delay of mitigation efforts to reach a 450 ppm CO₂ target by 2100, including variations where more developed countries implement mitigation immediately. Luderer et al. (2012) consider a similar 10-year delay and the same 450 ppm CO₂ target by 2100, with a scenario where Europe and all other industrialized countries

²⁸ Russ and van Ierland (2009) did not present estimates of total delay costs, so this paper is not included in the meta-analysis in Section II.

²⁹ We included three additional scenarios in van Vliet, den Elzen, and van Vuuren (2009) with alternate targets and models that were not reported in Clarke et al. (2009).

begin mitigation efforts in 2010. Luderer et al. (2013) analyze a scenario where countries implement fragmented policies before coordinating efforts in 2015, 2020, or 2030 to meet a target of 2°C above preindustrial levels by 2100, allowing for overshooting. Edmonds et al. (2008) consider targets of 450, 550, and 660 ppm CO₂, with newly developed and developing countries delaying climate action from a start date of 2012 to 2020, 2035 and 2050. Richels et al. (2007) estimate the additional cost of delay by newly developing countries until 2050 for a 450 and 550 ppm CO₂ target. Finally, Bosetti et al. (2009) estimate the additional cost when all countries delay climate action for 20 years with a goal of reaching a 550 ppm and 650 ppm CO_{2e} target by 2100.

Exhibit 16



Edited by David Leonhardt

The Up hot
CLIMATE CHANGE

There's a Formula for Deciding When to Extract Fossil Fuels

“Drill, Baby, Drill” became a popular campaign mantra back in the 2008 election cycle. But now we’re hearing the opposite call: “Leave It in the Ground.”

These calls come from environmentalists who see the end of drilling and mining as the way to avoid disruptive climate change. They direct these calls toward the federal government because it is estimated that about half of the carbon in technologically recoverable fossil fuels in the United States is on public lands.

Is there a middle ground that can supply the energy we need without causing significant climate damages? Yes. And it doesn’t involve exploiting all available resources, nor banning their use.

What if we continued to lease the rights to access fossil fuels on federal land but required the leases and royalty payments to reflect the full climate damages from these fuels? Doing so would put the market to work by unlocking fossil fuels that have the highest value in relation to their impact on the climate. The bonus: It provides money to pay for some of the damage of climate change.

We've seen the benefits of using our domestic resources over the last decade as the amount of our energy coming from domestic oil and gas resources increased 54 percent. Chiefly, we have lower fuel prices. We now pay 74 percent less for natural gas and 25 percent less for petroleum, compared with 2005. Further, net imports will account for just 23 percent of American liquid fuel supplies this year — down from 60 percent in 2005 — with important energy security benefits. Our carbon emissions are also below 2005 levels, with cheap natural gas having taken significant market share from coal, which is more carbon intensive.

At the same time, the combustion of fossil fuels causes climate change that is projected to impose myriad costs around the world. But in this regard, not all fossil fuels are created equal. The value per unit of energy, measured by the market price, is greater for some (like petroleum) than others (like coal). Further, some contain more carbon or result in the release of more emissions because of other factors like the extraction and transportation process, and inflict greater climate damages. Knowing the monetary value of climate damages associated with a ton of carbon emissions is therefore the key to this whole problem.

Luckily, there is a way to determine this. It is called the Social Cost of Carbon (S.C.C.), and the federal government sets it at \$40 per metric ton of CO₂ emissions. The S.C.C. is used to inform a wide variety of regulations that limit the use of fossil fuels, including emissions standards for vehicles, appliances and power plants. But the S.C.C. has not been used to guide extraction policies. (I was co-leader of an interagency group that set the S.C.C. when I worked in the Obama administration from 2009 to 2010.)

If the S.C.C. were applied as a part of leasing and royalty rates on federal lands, we would unlock resources with the greatest net benefits. To illustrate the consequences of such a shift, I did some calculations based on the spot prices for coal, petroleum and natural gas and their respective energy and carbon contents. The addition of a charge based on the S.C.C. is unlikely to

have a substantial effect on domestic production of petroleum: The spot price per million British thermal units (B.T.U.s) this year has been \$8.81, and the associated climate damages are \$2.98. If the federal government collected a charge of \$2.98 for each million B.T.U.s of petroleum extracted on federal lands, the revenue could be refunded directly to taxpayers or used to help the nation adapt to climate damages. The story is similar for natural gas; its value today exceeds the expected climate damages.

The case of coal is different, especially coal from the federal land in the Powder River Basin in Wyoming and Montana. The climate damages from coal mined from this region are five to six times greater than its market value (\$0.66 at market value versus \$3.89 of climate damages). Thus, a climate charge linked to the S.C.C. would probably make at least some of the coal mining in this region unprofitable. There is currently an opportunity for policy overhaul: The Department of the Interior is considering how to restructure lease terms for fossil fuels on federal lands. Further, a federal judge ruled last year that the government should take into account climate impacts when making decisions about mining on federal lands.

The application of an S.C.C.-related fee would meet many goals. Environmentalists would naturally like it, and so should fiscal conservatives who recognize that the federal government will be increasingly on the hook for climate damages (recall the more than \$50 billion of federal tax dollars appropriated in response to Hurricane Sandy). At the same time, this fee would not stop the development of economically attractive fossil fuels.

Such a change in policy would have challenges. There would inevitably be some shifting of fossil fuel production to private lands in the United States, as well as to other countries; but it would also reduce the long-run global supply of fossil fuels. Further, there would be a strong case for harmonizing S.C.C. charges with existing domestic climate regulations to ensure that the carbon policies operate as efficiently as possible. There is also a strong case for providing support to communities that experience meaningful declines in

economic activity because of an extraction fee linked to the S.C.C.

An efficient climate policy would price carbon throughout the global economy so that users of all fossil fuels recognized their climate costs. It does not appear likely that the current Paris climate negotiations will produce such a system. In the absence of such a policy, the solution doesn't need to be to use all fossil fuels, or to ban their usage. Common sense suggests that we use the ones that provide more value than harm and that we leave the others in the ground.

For a detailed analysis of the calculations, the technical document is available [here](#).

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