BEFORE THE APPEAL DECIDING OFFICER
USDA FOREST SERVICE, ROCKY MOUNTAIN REGION

WILDEARTH GUARDIANS, POWDER RIVER BASIN RESOURCE COUNCIL, AND SIERRA CLUB Appellants, v. PHIL CRUZ, Supervisor, Medicine Bow-Routt National Forest/ Thunder Basin National Grassland Deciding Official.	)))))))))))))))	Appeal of the Record of Decision to Consent to the North Porcupine Field Coal Lease by Application, WYW173408, Campbell County, Wyoming (Sept. 30, 2011)

NOTICE OF APPEAL, STATEMENT OF REASONS, AND REQUEST FOR RELIEF

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NOTICE OF APPEAL

Pursuant to 36 C.F.R. § 215 and 5 U.S.C. § 555(b), WildEarth Guardians, Powder River Basin Resource Council, and the Sierra Club (hereafter "Appellants") hereby appeal the September 30, 2011 Record of Decision ("ROD") signed by Phil Cruz, Supervisor of the Medicine Bow-Routt National Forest/Thunder Basin National Grassland, to provide the U.S. Forest Service's ("USFS's") consent to lease 5,120.67 acres of the Thunder Basin National Grassland ("TBNG") as part of the North Porcupine Field coal lease by application (hereafter referred to as the "North Porcupine LBA").[1, 2] The Bureau of Land Management ("BLM") is considering offering the North Porcupine Field coal LBA for sale, which consists of 6,364 acres and over 721 million tons of mineable Federal coal reserves. Before the BLM can offer the lease, the USFS must provide consent to leasing the 5,120.67 acres of lands that are part of the TBNG. *See* ROD at 2.

The North Porcupine LBA is being proposed by the BLM together with five other LBAs, which are collectively referred to as the Wright Area LBAs. Issuance of these coal leases would facilitate the expansion of the Black Thunder and North Antelope Rochelle coal mines, the two largest coal mines in the United States. Five of the six LBAs, including the North Porcupine LBA, require USFS consent before they can be issued.

Consent to the North Porcupine LBA would facilitate coal mining specifically at the North Antelope Rochelle coal mine in the Powder River Basin of northeastern Wyoming, the largest coal producing region in the United States. The North Antelope Rochelle coal mine, a massive strip mining operation, is one of the largest coal mines in the United States. *See* Peabody Energy, http://www.peabodyenergy.com/Media/factsheets/NARoch.asp (last accessed Nov. 17, 2011). By issuing his consent, Supervisor Cruz is conceding any future right by the USFS to restrict or otherwise modify coal mining activities undertaken to develop the North Porcupine LBA.

INTRODUCTION

Appellants bring this appeal because the Supervisor's decision suffers from a number of fatal flaws. In particular, although the ROD relies on the Wright Area Coal Lease Applications Final Environmental Impact Statement (hereafter referred to as the "Wright Area Coal FEIS" or "FEIS") prepared by the BLM, this FEIS was not prepared by the USFS and further fails to analyze and assess whether the proposed actions would fully comply with substantive and unique USFS obligations, including TBNG Land and Resource Management Plan (hereafter referred to as the "Grassland Plan") standards and guidelines and special use regulations.

Adding to our concern is that there does not appear to be any legitimate need for the North Porcupine LBA. According to the ROD, even if the North Porcupine LBA is rejected, "Other national coal producers have the capacity to produce coal and replace the production from

[1] Pursuant to 36 C.F.R. § 215.14(b)(3), WildEarth Guardians is the lead Appellant.

[2] Throughout this appeal, we refer to "USFS" and "Supervisor" interchangeably.

this existing mine." ROD at 9. The Supervisor further notes in his ROD that even if the LBA is rejected, the North Antelope Rochelle coal mine would continue operating for 9.9 years. *See id.* The only purported need for issuing the lease appears to be to buttress the competitiveness of the North Antelope Rochelle coal mine—not to meet any domestic energy needs.[3] As the Supervisor states, a denial of the proposed coal lease would only "deny the mine operator the ability to compete with other operators in an open market[.]" *Id.* This hardly seems like a valid reason to consent to leasing.

Critically, the Supervisor's decision inappropriately dismisses taking any reasonable action to address the foreseeable impacts of global climate change caused by dramatic increases in greenhouse gas emissions, in violation of the National Environmental Policy Act ("NEPA") and the Agency's substantive duties under its special use regulations. This is disturbing in light of the fact that USFS Chief Tom Tidwell has identified global climate change as a significant threat to the forests and grasslands across the country. As the Chief stated in testimony to the Senate Appropriations Committee:

> Broad scientific consensus confirms that global climate change is real and that the impacts are altering forests and grasslands, increasing the frequency of disturbance events and diminishing the ecosystem services they provide. Some of the most urgent forest and grassland management problems of the past 20 years—wildfires, changing water regimes, and expanding forest insect infestations—have been driven, in part, by a changing climate; future impacts are likely to be even more severe.

Statement of Tom Tidwell, USDA Forest Service Chief, Before the Senate Committee on Appropriates Subcommittee on Interior Environment and Related Agencies (March 17, 2010) at 4, *available at* http://appropriations.senate.gov/ht-interior.cfm?method=hearings.download&id=2bcfbdfe-80cd-4dbb-b0e4-1d6a2d62288f (last accessed Nov. 17, 2011). This statement is attached as Exhibit 1. Notably, the Chief is not alone in his concern over the impacts of global climate change. On October 5, 2009, President Obama, responding to concerns over global climate change, called on all federal agencies to "measure, report, and reduce their greenhouse gas emissions from direct and indirect activities." President Obama, Executive Order No. 13514, *Federal Leadership in Environmental, Energy, and Economic Performance*, Section 1 (Oct. 5, 2009), *available at* http://edocket.access.gpo.gov/2009/pdf/E9-24518.pdf (last accessed Nov. 17, 2011).

Despite these recognitions that global climate change is a real threat to America's forests and grasslands, and despite calls from the President of the United States to reduce greenhouse gas emissions, the Supervisor did nothing to address the global climate change impacts associated with the North Porcupine LBA. This was not a minor oversight. The North Porcupine LBA includes 721,154,828 tons of mineable Federal coal reserves. *See* ROD at 2. This coal will

[3] In fact, Peabody Energy, the owner of the North Antelope Rochelle coal mine and applicant for the North Porcupine LBA, has announced that it is expecting to increase exports of Wyoming coal to Asia. *See* Tomich, J., "Peabody planning Asian coal shipments through Washington," *St. Louis Post-Dispatch* (March 11, 2011), *available at* http://www.stltoday.com/business/local/article_45e1b38e-44ef-5cf9-bea9-2f05b3c1fe04.html (last accessed Nov. 17, 2011). This article is attached as Exhibit 2.

be sold and burned in power plants, leading to the release of massive amounts of carbon dioxide (“CO_2”)—the greenhouse gas most responsible for fueling global climate change.[4] ***All told, the amount of coal slated to be mined as part of the North Porcupine LBA will lead to the release of 1,196,395,860 metric tons of CO_2.***[5] This amount of CO_2 is not insignificant—it equals 20 percent of all CO_2 emissions released in the United States in 2009.[6]

However, Supervisor Cruz’s oversight is even more significant in light of the cumulative role the Powder River Basin—the nation’s largest coal producing region—plays in fueling the United States’ contribution to global warming. Already, the electricity generation sector is the largest source of greenhouse gases in the U.S., largely due to CO_2 emissions. *See* U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, 1990-2009, EPA 430-R-11-005 (April 15, 2011), at 3-1 *available at* http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Report.pdf (last accessed Nov. 17, 2011). The Executive Summary and Chapter 3 of this report are attached as Exhibit 3. The EPA reports, “The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States.” *Id*. at 3-10. Coal-fired power plants release more than eighty percent of all greenhouse gases from the electricity generation sector, including more than 1.747 billion metric tons of CO_2—nearly thirty percent of the nation’s total greenhouse gas inventory and thirty-three percent of all CO_2 released in the U.S. *Id*. at 3-8. ***This makes coal-fired power plants the largest single source of CO_2 in the country.***

As the largest producer of coal in the United States, ***coal mining in the Powder River Basin is therefore linked to more greenhouse gas emissions than almost any other activity***.

The BLM, and by extension the USFS, does not deny this. According to the BLM, “Coal

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[4] According to the U.S. Environmental Protection Agency (“EPA”), “six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations.” 74 Fed. Reg. 66496 (Dec. 15, 2009). The Administrator expounded:

> The body of scientific evidence compellingly supports this finding. The major assessments by the U.S. Global Climate Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) serve as the primary scientific basis supporting the Administrator’s endangerment finding. The Administrator reached her determination by considering both observed and projected effects of greenhouse gases in the atmosphere, their effects on the climate, and the public health and welfare risks and impacts associated with such climate change. The Administrator’s assessment focused on public health and public welfare impacts within the United States. She also examined the evidence with respect to impacts in other world regions, and she concluded that these impacts strengthen the case for endangerment to public health and welfare because impacts in other world regions can in turn adversely affect the United States.

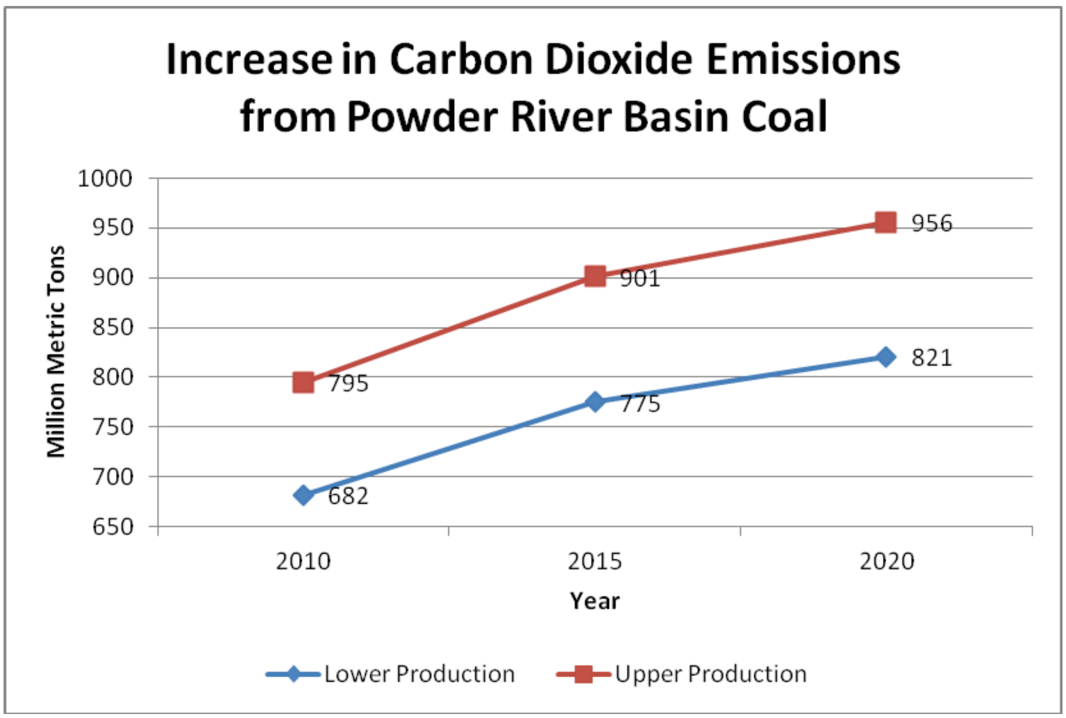
Id. at 66496, 66497. Among the six greenhouse gases that the Administrator of the EPA found endangered public health and welfare: ***carbon dioxide***.

[5] According to the BLM, every ton of coal burned releases 1.659 metric tons of CO_2. *See* FEIS at 4-140.

[6] According to the EPA’s most recent greenhouse gas emission inventory, CO_2 emissions in the United States equaled 5,505.2 million metric tons. *See* U.S. EPA (2011), “Inventory of U.S. Greenhouse Gas Emissions and Sinks: Fast Facts,” *available at* http://epa.gov/climatechange/emissions/downloads11/GHG-Fast-Facts-2009.pdf (last accessed Aug. 25, 2011). This fact sheet is attached as Exhibit 4.

production from the Wyoming PRB [Powder River Basin] represented approximately 43.4 percent of the coal used for power generation in 2008, which means that combustion of Wyoming PRB coal to produce electric power was responsible for about 12.8 percent of the estimated U.S. CO_2 emissions in 2008." FEIS at 4-137. This amounts to forty percent of all CO_2 released by U.S. coal-fired power plants. No other activity in the United States contributes as much CO_2.

This is not the end of it. According to the BLM, ***CO_2 emissions associated with coal mining in the Powder River Basin are expected to increase by more than 20 percent by 2020***, under both low- and upper-production scenarios. *See* FEIS at 4-138. As the chart below indicates, the Powder River Basin could ultimately be responsible for 956 million metric tons of CO_2 emissions. The reason? Because of expanded coal mining facilitated by the approval of new coal leases. Not only is the BLM proposing to offer the North Porcupine LBA, but as the Supervisor notes in his ROD, "there are currently 12 pending LBAs in the Wyoming portion of the PRB [comprising as originally proposed] approximately 34,571 acres and 3.722 billion tons of Federal coal." ROD at 35.



Supervisor Cruz comes up with a number of creative excuses to avoid addressing CO_2 emissions connected with the North Porcupine LBA, but ultimately these excuses are nothing more than punting. The fact is that the USFS was obligated to address the potentially significant impacts of the CO_2 emissions associated with the North Porcupine LBA. There was no valid reason for ignoring such a duty.

The failure to adequately address global climate change impacts unfortunately comes as no surprise. Supervisor Cruz's ROD seems to reflect a complete lack of independent review on the part of the USFS and seems only to rubberstamp the BLM's proposal to offer the North

Porcupine LBA. The ROD primarily repeats assertions and assumptions made by the BLM and for the most part, seems as if it was written from the perspective of a BLM decisionmaker, not a USFS line officer. It is notable that Supervisor Cruz's ROD contains a number of statements that are printed verbatim in recent BLM RODs issuing coal leases in the Powder River Basin, including the BLM's most recent North Porcupine ROD.[7]

For such a major decision with such significant ramifications, it is disappointing that the Supervisor would cut such important corners. The USFS has an independent duty to assess whether it is appropriate to offer its consent to coal leasing on the TBNG in light of its unique responsibilities and obligations to the public and to the lands under its management. The consent decision is fully discretionary, meaning the USFS is not limited to simply deferring to the BLM, or to shortcutting its deliberative process. For the reasons fully stated below, Appellants request that Supervisor Cruz's ROD be vacated.

APPELLANTS

WILDEARTH GUARDIANS is a Santa Fe, New Mexico-based nonprofit organization with offices in Denver and Phoenix, and members throughout the American West. WildEarth Guardians is dedicated to protecting and restoring the wildlife, wild places, and wild rivers of the American West, and to safeguarding the Earth's climate. WildEarth Guardians has members throughout the American West, including Wyoming, that utilize the region that will be affected by the proposed decision to allow the leasing of the North Porcupine LBA on the TBNG.

POWDER RIVER BASIN RESOURCE COUNCIL is a member-based conservation group in Wyoming. The majority of Powder River Basin Resource Council's approximately 1,000 members live in the Powder River Basin of Wyoming. The group has a long history of involvement working for responsible coal leasing and mining. Formed in 1973 by ranchers and concerned citizens of Wyoming to address the impacts of strip mining on rural people and communities, Powder River Basin Resource Council has worked for the preservation and enrichment of Wyoming's agricultural heritage and the responsible use of land, mineral, water, and air resources to sustain the livelihood of present and future generations.

SIERRA CLUB is a national nonprofit organization of approximately 1.3 million members and supporters dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club's concerns encompass climate change, air quality impacts, water quality, wildlife, and other environmental concerns. The Sierra Club's highest national priority campaign is its "Move Beyond Coal" Campaign, which aims to transition the nation away from coal and toward clean

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[7] *Compare, e.g.*, Rationale for issuing North Porcupine LBA in BLM, *Record of Decision Environmental Impact Statement for the North Porcupine Field Coal Lease Application, WYW173408* (October 2011) at 7-12, *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/hpdo/Wright-Coal/n-porcupine.Par.91450.File.dat/ROD.pdf (last accessed Nov. 17, 2011) with Supervisor's Rationale in his ROD at 8-12. The BLM's North Porcupine ROD is attached as Exhibit 5.

energy solutions. The Wyoming Chapter of the Sierra Club has approximately 900 members in the State of Wyoming.

Appellants submitted comments on May 16, 2011 on the USFS's proposed consent to the North Porcupine LBA and variously submitted comments on the BLM's Wright Area Draft EIS and FEIS.

STATEMENT OF REASONS

I. The USFS Violated NEPA By Failing To Prepare Its Own Environmental Analysis.

As a threshold matter, the USFS's consent decision must be overturned because the Supervisor failed to satisfy NEPA's requirements in issuing the ROD. Under NEPA, agencies must prepare an EIS for actions – such as the North Porcupine LBA—that significantly affect the environment. *See e.g.* 40 C.F.R. § 1502.4. Furthermore, even if an action's environmental effects are found to be modest, the agency must still prepare an environmental assessment ("EA") and a finding of no significant impact ("FONSI"). *Id.* § 1508.13. Here, however, the USFS did neither. The agency issued the ROD without preparing an EIS or an EA/FONSI. By issuing a consent decision without an environmental analysis, the Supervisor violated NEPA.

In his Response to Comments ("RTC"), attached as Appendix C to the ROD, the Supervisor repeatedly mentions the USFS's role as a "cooperating agency" that assisted with the preparation of BLM's EIS. *See e.g.* RTC at 50. However, USFS's assistance in the preparation of BLM's EIS does not excuse it from meeting its own NEPA obligations. Under NEPA, each federal agency has an independent duty to ensure that NEPA and other federal laws are being followed. An agency cannot simply rely on another agency's EIS in lieu of performing its own, independent environmental analysis. *Anacostia Watershed Society v. Babbitt*, 871 F. Supp. 475, 485 (D.D.C. 1994). Indeed, "[t]he attempt to rely entirely on the environmental judgments of other agencies is in fundamental conflict with the basic purpose of NEPA." *Idaho v. I.C.C.*, 35 F.3d 585, 596 (D.C. Cir. 1994); *see also Calvert Cliffs' Coordinating Comm. v. Atomic Energy Comm'n,* 449 F.2d 1109, 1129 (D.C. Cir. 1971).

NEPA's implementing regulations allow a cooperating agency to use a lead agency's EIS under certain circumstances. *See* 40 C.F.R. § 1506.3(c). But to do so, an agency must first satisfy two specific requirements: first, the agency must perform its own independent review of the lead agency's EIS and determine that the EIS satisfies its own standards and procedures; second, the agency must actually *adopt* that EIS as its own. *Id.*; *Anacostia Watershed*, 871 F. Supp. at 485. In this case, the USFS has met neither of these requirements. The Supervisor simply relied on BLM's FEIS in issuing the ROD. *See* ROD at 7 ("Based, in large part, on . . . the Final EIS . . . I have decided to approve Alternative 2 as modified."). As the U.S. District Court for the District of Columbia has held that "an agency may not rely on the compliance of other agencies with NEPA as a justification for its failure to comply with the Act." 871 F. Supp. at 185. Because the USFS improperly relied on another agency's FEIS, and failed to perform its own, independent environmental analysis, the ROD must be reversed.[8]

A. The Supervisor Failed to Consider a Reasonable Range of Alternatives

The USFS's failure to perform its own NEPA analysis is particularly problematic in the case of the North Porcupine LBA, as well as the other Wright Area LBAs. NEPA requires federal agencies to "[r]igorously explore and objectively evaluate *all* reasonable alternatives." 40 C.F.R. § 1502.14(a) (emphasis added). Here, the USFS's reliance on BLM's EIS prevented the USFS from conducting an adequate alternatives analysis for uses of USFS surface lands within the North Porcupine lease area, either alone or cumulatively across the six Wright Area LBAs. Mining the six Wright Area lease tracts will result in the removal of over 50,000 acres of topsoil and vegetation, greatly impacting lands used for wildlife habitat and rangeland grazing. FEIS at 3-185. By any measure, leasing and subsequent mining of the North Porcupine and at least four other Wright Area LBAs will significantly, and in some cases irreversibly, impact USFS lands. It is therefore incumbent upon the USFS to conduct an alternatives analysis, which is the "heart" of NEPA analysis. 40 C.F.R. § 1502.14.

As discussed below, a host of reasonable alternatives related to climate change, air quality, water quality and quantity, and reclamation are fully available to be considered by the USFS. As the surface owner of much of the North Porcupine lease area, USFS has a duty under NEPA to consider alternatives, such as lease stipulations, that could be applied to mitigate the significant impacts that will result from leasing and subsequent mining of this LBA. The Supervisor acknowledges that the USFS has the authority to "prescribe terms and conditions to be imposed on that lease." ROD at 2, *citing* 43 C.F.R. §§ 3400.3-1, 3420.4-2. Further, the USFS notes that the agency already imposes "standard coal lease stipulations addressing compliance with basic requirements of the environmental statutes." ROD at 6. Including lease stipulations such as those suggested by Appellants would be fully consistent with this existing authority.

In addition to failing to consider additional alternatives and mitigation measures as required by NEPA, the Supervisor's reliance on BLM's alternatives analysis is illegal because BLM's NEPA does not properly disclose the impacts from the alternatives BLM does consider in its EIS. The cumulative impacts section of BLM's FEIS does not consider the "no action" alternative or differentiate between the proposed and preferred alternatives. *See* FEIS Chapter 4. Additionally, in the lease specific impacts section, BLM combines discussion of impacts of the Proposed Action and Alternatives 2 and 3. *See* FEIS at 3-13, 3-19, 3-30, 3-45, 3-57, 3-82, 3-93, 3-97, 3-111, 3-143, 3-153, 3-162, 3-173, 3-177, 3-185, 3-192, 3-196, 3-206, 3-210, 3-221, 3-229, 3-233, 3-263, 3-275, 3-283, 3-294, 3-299, 3-302, 3-323-26. The "heart" of an EIS is a comparison of various alternatives to the proposed action and the impacts analysis within BLM's FEIS is missing this comparison.

The CEQ has provided guidance to agencies that NEPA requires that "cumulative effects must be evaluated along with the direct effects and indirect effects… of each alternative…" and that "…as the proposed action is modified or other alternatives are developed (usually to avoid

[8] Even if the Forest Service could have lawfully relied on BLM's FEIS to satisfy its NEPA obligations, the ROD must still be overturned because BLM's FEIS is legally deficient. The inadequacies of BLM's FEIS are discussed below.

or minimize adverse effects), additional or different cumulative effects issues may arise." CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act*, January 1997.

BLM responded that this comparative analysis is not necessary because the cumulative effects analysis in the FEIS "gives a 'worst case' type of impact analysis as far as the Wright area mines['] contribution to cumulative impact[s], because if the action alternatives are not chosen, some of the cumulative production would shift from Wright Area mines to other PRB producers, or to producers outside the PRB." BLM, *Analysis and Response of Public Comments Received on the Wright Area Coal Final Environmental Impact Statement* (March 2011) at 9, *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/hpdo/Wright-Coal/south_hilight_ROD/FEIS_comments.Par.98623.File.dat/Comment%20Response.pdf (last accessed Nov. 17, 2011). BLM's argument amounts to mere rhetoric and an unsubstantiated excuse for failing to take responsibility and analyze the impacts of its actions. BLM's FEIS is illegally flawed because it does not compare the environmental trade-offs that directly result from the actions of the agency or other Federal agencies, such as the USFS. If the USFS continues to consent to leasing more coal, more coal will be available for purchase by utilities and this drives down the price of coal and creates a situation where utilities are more likely to continue to burn coal as opposed to switching to cleaner sources of energy. Cheap and easily obtainable coal supplies are dwindling and the USFS is the surface owner over some of the world's best coal reserves in the TBNG. BLM's FEIS notes that production related to these lease tracts will likely be between 291 and 307 million tons of coal per year. *See* FEIS at 2-9. According to Energy Information Administration data, this amounts to *over a quarter of U.S. production*. *See* EIA, *Coal Production and Number of Mines by State and Mine Type* (2009), *available at* http://www.eia.gov/cneaf/coal/page/acr/table1.html (last accessed Nov. 17, 2011). It is very unlikely that this amount of coal could easily be replaced by "other PRB producers" or even "producers outside the PRB." In fact, BLM even states that the preferred alternative was selected "to assure that tracts contain enough coal to allow market demands to be met." BLM, Analysis of Public Comments on FEIS at 9. Throughout the FEIS, BLM gives short shrift to the environmental benefits that could be realized by selecting the no action alternative or choosing other environmentally preferable alternatives, such as leasing less coal, leasing fewer tracts of coal, or limiting each mine to a single tract as suggested by Appellants in their comments. *See e.g.* Powder River Basin Resource Council, Comments on Wright Area Coal Final Environmental Impact Statement (Aug. 30, 2010) at 4, *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/hpdo/Wright-Coal/south_hilight_ROD/FEIS_comments.Par.44863.File.dat/PRBRC.pdf (last accessed Nov. 17, 2011).

A comparison of impacts of the various alternatives is especially important in relation to climate change impacts. The USFS needs to include a full consideration of qualitative impacts that will result from the various alternatives. BLM's FEIS only includes a very cursory overview of climate impacts and does not differentiate impacts from the proposed action or alternatives. Although there are some uncertainties regarding the state of climate science and emissions accumulate at a global scale, an analysis of likely impacts is possible and should be included as a basis for comparison amongst the various alternatives.[9] Instead, BLM claims that if it does not

[9] In the context of a coal-fired power plant where quantified greenhouse gas emissions were known, EPA told BLM that those emissions could reasonably be attributed to climate change impacts. *See* Letter from K. Goforth, U.S.

lease the coal tracts, carbon emissions will not be reduced. FEIS at 4-141 ("It is not likely that selection of the No Action alternatives would result in a decrease of U.S. CO_2 emissions attributable to coal mining and coal-burning…"). Taken in the positive, BLM and the USFS are claiming that leasing the coal will not increase carbon emissions. This is an illogical claim and is unsupported by any analysis or economic or scientific information. Clearly, if BLM leases the coal, the coal will be mined and burned to produce electricity. This will produce carbon dioxide emissions and will contribute to global climate change. BLM claims that other coal may fill the gap for utilities (*see* FEIS at 4-141), but at the same time the agency acknowledges that "Many other states rely on Wyoming for coal reserves in view of the fact that Wyoming coal is used to generate electricity in 36 states." FEIS, Appendix I, Response to Comments at 14. As discussed above, the Black Thunder and North Antelope Rochelle coal mines represent 50% of Wyoming PRB coal production and amount to just over 25% of U.S. production. *See* FEIS at 4-139. Utilities would not easily be able to replace that amount of coal supply and even if they were able to replace it, the coal would most likely cost more to mine, transport, and burn (therefore increasing the cost of coal-fired electricity vis-à-vis renewable energy and energy efficiency alternatives).[10] As acknowledged by BLM in the FEIS, the PRB coal leasing program is currently necessary to meet the nation's energy needs. Thus, a selection of a no action or reduced leasing alternative will likely lead to fuel switching by utilities and/or a greater investment in demand-side management programs and a subsequent reduction in greenhouse gas emissions. If the USFS or BLM has information that proves otherwise, it needs to be disclosed in the FEIS in order to meet the "substantial evidence" and "hard look" requirements of NEPA. *Robertson v. Methow Valley*, 490 U.S. 332, 352 (1989).

BLM's impacts analysis of the various alternatives is therefore legally flawed and may not be relied upon by the USFS to meet NEPA's requirements.

II. The Secretaries of Agriculture and Interior Have Not Made Findings That Surface Mining Can Occur on Lands Within the TBNG That Are Part of the North Porcupine LBA

The Surface Mining Control and Reclamation Act ("SMCRA") prohibits surface mining on National Forest System ("NFS") lands. *See* 30 U.S.C. § 1272(e)(2) and 30 C.F.R. §

EPA, to J. Peterson, BLM, "Subject: Final Environmental Impact Statement for the White Pine Energy Station Project Nevada [CEQ# 20080394]" (November 24, 2008) ("[…]conclusions discounting the quantifiability of the project's contributions to climate change do not appear to be accurate in light of other available, recent analyses"). In the letter, EPA cites efforts to quantify specific impacts of greenhouse gas emissions by the National Highway Transportation and Safety Administration in its Final EIS on the proposed Corporate Average Fuel Economy Standards. Corporate Average Fuel Economy Standard Final EIS, *available at* www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated Files/CAFE FEIS.pdf (last accessed Nov. 17, 2011).

[10] BLM states that "Fueled by recent oversees demand, Appalachian coal prices have increased dramatically. PRB coal may help to fill the gap left by the Appalachian coal exports…." FEIS at 2-69. The Agency also states, "PRB coal reserves are in thick seams, resulting in more production from areas of similar land disturbance, and lower mining and reclamation costs." FEIS at 4-136. BLM also asserts that Powder River Basin coal also has lower sulfur content than other sources of coal and thus without its availability, utilities may need to deploy expensive sulfur dioxide reduction scrubbers or other technology, which would increase the price of coal power.

761.11(b). This prohibition is absolute, except where the Secretary of Interior has found that "there are no significant recreational, timber, economic, or other values that may be incompatible with surface coal mining operations," and where:

> With respect to lands that do not have significant forest cover within national forests west of the 100th meridian, ***the Secretary of Agriculture has determined that surface mining is in compliance*** with the [Surface Mining Control and Reclamation] Act, the Multiple Use Sustained Yield Act of 1960, 16 U.S.C. 528-331; the Federal Coal Leasing Amendments Act of 1975, 30 U.S.C. 181 et seq.; and the National Forest Management Act of 1976, 16 U.S.C. 1600 et seq.

30 U.S.C. § 1272(e)(2)(B) and 30 C.F.R. § 761.11(b)(2); *see also* FSM 2822.15.

Here, there is no question that the prohibition found in SMCRA and its implementing regulations applies. The TBNG is a part of the NFS system of lands. Furthermore, the TBNG is located west of the 100th meridian and "lacks significant forest cover." The North Porcupine LBA also would exclusively allow surface mining. Indeed, the LBA would facilitate surface mining at the North Antelope Rochelle coal mine, one of the largest coal mines in the United States.

Despite this, the Secretary of Agriculture has not made a determination that surface mining of the North Porcupine LBA would be in compliance with those statutes, in accordance with 30 U.S.C. § 1272(e)(2)(B) and 30 C.F.R. § 761.11(b)(2). There is also no evidence that the Secretary's duties under SMCRA have been delegated to any Forest Supervisor. Thus, in consenting to the North Porcupine LBA, the Supervisor's ROD violates SMCRA and its implementing regulations. Unless and until the Secretary of Agriculture determines that surface mining is in compliance with the provisions of 30 U.S.C. § 1272(e)(2)(B) and 30 C.F.R. § 761.11(b)(2), the USFS cannot consent to the North Porcupine LBA.

In the RTC, the Supervisor does not dispute that the Secretarial findings required by 30 U.S.C. § 1272(e)(2) and 30 C.F.R. § 761.11(b) were never made. Instead, he claims that these requirements do not apply because the TBNG is not part of a National Forest. *See e.g.* RTC at 48. The Supervisor's novel position is unreasonable and should be rejected. As an initial matter, the USFS has *already* conceded that the TBNG is part of a National Forest. Indeed, the EIS for the Grassland Plan repeatedly recognizes that the TBNG is an administrative unit of the Medicine Bow-Rout National Forest. *See* Grassland Plan EIS at 1-1, 1-2, 1-4.

The Supervisor's position also conflicts with governing law. Congress has made clear that "[t]he 'National Forest System' shall include all national forest lands reserved or withdrawn from the public domain of the United States, all national forest lands acquired through purchase, exchange, donation, or other means, ***the national grasslands*** and land utilization projects administered under title III of the Bankhead-Jones Farm Tenant Act, and other lands, waters, or interests therein which are administered by the Forest Service or are designated for administration through the Forest Service as a part of the system." 30 U.S.C. § 1609 (emphasis added); *see also* 64 Fed. Reg. 70766, 70825 (Dec. 17, 1999) (BLM describing "western national forests and national grasslands" as "Section 522(e)(2) lands"); *Meridian Land and Mineral Co. v. Hodel*, 843 F.2d 340, 345 n.3 (9th Cir.1988) (citing SMCRA legislative history which noted that "[t]here are some 7 billion tons of potentially surface minable coal within the boundaries of the ***national forest system***. The starting point of the committee language [for § 1272(e)(2)] is the exclusion of all surface coal mining within the ***national forest system***.") (emphasis added).

In sum, by arguing that 30 U.S.C. § 1272(e)(2) and 30 C.F.R. § 761.11(b) do not apply to the TBNG—which is indisputably part of the NFS—the Supervisor violated SMCRA and the ROD must be reversed.

Furthermore, it is not clear that the Supervisor could make the required determination that surface mining activities will comply with SMCRA, particularly the requirements that mining operations engage in contemporaneous reclamation (*see* 30 U.S.C. § 1202(e); Wyo. Land Quality Regulations Ch. 4 § 2(b)(i), (k)(i)), and that they "minimize[] disturbance to the prevailing hydrologic balance in the permit area and in adjacent areas." Wyo. Land Quality Regulations Ch. 4 § 2(h)(ii). The most recent federal Office of Surface Mining Reclamation and Enforcement evaluation of surface coal mining in Wyoming shows that for all mines, including the North Antelope Rochelle mine, the gap between acres disturbed and acres reclaimed continues to grow.[11] See sections IX and X below for further discussion of factors that would preclude the USFS from determining that the proposed surface mining operations can be conducted in accordance with SMCRA.

Unfortunately, the USFS's erroneous assertion that it is not obligated to meet the requirements of 30 U.S.C. § 1272(e)(2)(B) of SMCRA before offering its consent to the North Porcupine LBA prevented the Agency from even assessing whether the North Antelope Rochelle mine is compliance with SMCRA. However, because SMCRA imposes an independent obligation on the USFS to determine that mining operations on a proposed lease will comply with SMCRA, the USFS cannot merely assume that the mine operator will comply with its SMCRA permit, or that the SMCRA regulator (here, the Wyoming Department of Environmental Quality) will ensure full compliance with the law. At the very least, the USFS should have withheld its consent until such time as the mines can explicitly demonstrate their current compliance with SMCRA, and their capacity to comply with SMCRA in the future. The Supervisor's ROD must be reversed on this ground.

III. The Supervisor Failed to Analyze and Assess Global Climate Change Impacts in Accordance with NEPA

Congress enacted NEPA to, among other things, "encourage productive and enjoyable harmony between man and his environment" and to promote government efforts "that will prevent or eliminate damage to the environment." 42 U.S.C. § 4321. To fulfill this goal, NEPA requires federal agencies to prepare an EIS for all "major Federal actions significantly affecting the environment." 42 U.S.C. § 4332(2)(C); 40 C.F.R. § 1501.4. The Agency must describe "any adverse environmental effects which cannot be avoided should the proposal be implemented." 42 U.S.C. § 4332(C)(ii). Overall, an EIS must "provide [a] full and fair discussion of significant impacts" associated with a federal decision and "inform decisionmakers and the public of the

[11] *See* OSMRE, 2010 Evaluation Report for Wyoming at Appendix C, *available at* http://www.osmre.gov/Reports/EvalInfo/2010/WY10-reg.pdf (last accessed Nov. 17, 2011).

reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the human environment." 40 C.F.R. § 1502.1.

In an EIS, the federal Agency must analyze and assess the significance of the direct, indirect, and cumulative impacts of a major Federal action. 42 U.S.C. § 4332(2)(C); 40 C.F.R. §§ 1502.16, 1508.7, and1508.8. NEPA requires federal agencies, including the USFS, to include within an EIS "alternatives to the proposed action." 42 U.S.C. § 4332(2)(C)(iii). The alternatives analysis is the "heart" of a NEPA document, and the statute's implementing regulations emphasize an Agency's duty to "[r]igorously explore and objectively evaluate all reasonable alternatives." 40 C.F.R. § 1502.16. NEPA also requires that agencies mitigate the adverse environmental impacts of their actions. *Id.* at §§ 1502.14(f) and 1502.16(h). Mitigation includes avoiding impacts, minimizing impacts, rectifying impacts, or compensating for impacts. *Id*. at § 1508.20.

In this case, the USFS failed to adequately analyze and assess the climate change impacts of consenting to the issuance of the North Porcupine LBA and failed to consider alternatives to address these impacts. As explained already, this oversight is monumental. In consenting to the sale of over 721 million tons of coal, the USFS has in turn consented to the release of 1,196,395,860 metric tons of CO_2 resulting from the combustion of that coal, which is by any measure a significant amount. According to the EPA, this amount of CO_2 equals the amount of annual greenhouse gas emissions from 234,587,424 passenger vehicles or, put another way, the annual CO_2 emissions of 283 coal-fired power plants. *See* EPA, *Greenhouse Gas Equivalencies Calculator*, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results (last accessed Nov. 17, 2011). The BLM has already disclosed that coal from the Powder River Basin as a whole is responsible for roughly 13 percent of the nation's CO_2 emissions, and that this amount is projected to increase 20% by 2020. *See* FEIS at 4-137—4-138. The North Porcupine LBA therefore promises to exacerbate the role of both the Powder River Basin cumulatively and the North Antelope Rochelle coal mine specifically as major contributors to global climate change in the United States. Despite this, the Supervisor made no effort to address these impacts under NEPA. In failing to adequately address these impacts, the Supervisor's consent to the North Porcupine LBA is fatally flawed.

A. The Supervisor Failed to Analyze and Assess the Impacts of CO_2 Emissions that Would Result from the North Porcupine LBA

To begin with, the Supervisor failed to analyze and assess the indirect CO_2 emissions that would result from the North Porcupine LBA. The Wright Area Coal FEIS discloses that "almost all coal that is currently being mined in the Wyoming PRB is being used by coal-fired power plants to generate electricity to generate electricity." FEIS at 3-323. Thus, consent to the sale and issuance of the North Porcupine LBA will in turn lead to the burning of coal in power plants and the associated release of CO_2. Such impacts are indirect in that they "are caused by the action and are later in time or farther removed in distance, but are still ***reasonably foreseeable***." 40 C.F.R. § 1508.8(b) (emphasis added).

It is not disputed that the combustion of coal is a foreseeable impact of consenting to the North Porcupine LBA. Indeed, the Supervisor asserts in his ROD that the LBA is purportedly needed to meet the nation's energy needs. Furthermore, together with other past, present, and reasonably foreseeable impacts, these impacts are cumulative in accordance with 40 C.F.R. § 1508.7.

Under NEPA regulations, an EIS is required to include an analysis and assessment of impacts, including a discussion of "indirect effects and their significance." 40 C.F.R. § 1502.16(b). Effects include "cumulative impacts." 40 C.F.R. § 1508.8. In this case, although the Supervisor recognized that consenting to the issuance of the North Porcupine LBA would lead to the release of CO_2 emissions, he did not adequately analyze these effects, nor assess their significance in accordance with 40 C.F.R. § 1502.16(b).

The Wright Area Coal FEIS does make qualitative statements regarding the potential CO_2 emissions from the North Porcupine LBA, stating that "CO_2 emissions related to burning coal that is produced from the three applicant mines to generate electricity would be extended as a result of leasing and mining[.]" FEIS at 4-138. However, the FEIS then asserts that, "[i]t is not possible to accurately project the level of CO_2 emissions that burning the coal from the six WAC [Wright Area Coal] LBA tracts would produce due to uncertainties about what emission limits would be in place at that time or where and how the coal in these LBA tracts would be used if they are leased and the coal is mined." *Id*. at 4-139. This supporting logic is confusing, to say the least. Although the FEIS may be uncertain "about what emission limits will be in place" in the future, this uncertainty does not overshadow the certainty that exists today, which is that there are currently no limits on CO_2 emissions from coal-fired power plants—a fact stated in the FEIS on page 4-143. This perceived "uncertainty" about the future does not absolve the Agency of complying with its duties under NEPA in the present. Further, the FEIS's uncertainty about "where and how the coal" would be used is simply absurd. There is no question that the coal from the North Porcupine LBA will be mined and burned in coal-fired power plants.[12]

The Supervisor appears to rest his analysis on his belief that the CO_2 emissions from the North Porcupine LBA would simply come from other coal sources. He asserts in his ROD that if the leases are not authorized, the coal will simply be produced by other mines outside the Powder River Basin, in essence arguing that the CO_2 emissions simply do not matter. The Supervisor claims, for instance, that "[t]he inability of the North Antelope Rochelle Mine...to offer reserves in the coal market would not cause electric generators to stop burning coal" and that "[o]ther national coal producers have the capacity to produce coal and replace the production from this existing mine." ROD at 9 *see also* FEIS at 4-141 ("It is not likely that selection of the No Action alternatives would result in a decrease of U.S. CO_2 emissions attributable to coal mining and coal-burning power plants in the longer term[.]"). Not only is there is no analysis or information presented or cited to support this assertion, but this baseless assertion is contrary to reality.

[12] In fact, annual fuel receipt data from the EIA specifically lists every single coal-fired power plant that burned coal from the North Antelope Rochelle coal mine. *See* Exhibit 6, EIA Form 923 Data for North Antelope Rochelle coal mine (2010), *available at* http://www.eia.gov/cneaf/electricity/page/eia423.html (last accessed Nov. 17, 2011). According to this data, there are at least 98 coal-fired power plants that fully or partially burned coal from the North Antelope Rochelle mine in 2009. Thus, it is clearly possible to reasonably ascertain where and how coal from the North Antelope Rochelle coal mine will be used, contrary to the Supervisor's and the FEIS's assertion otherwise.

The North Antelope Rochelle coal mine is one of the largest coal mines in the United States. In fact, it is not only the largest coal producer in the Powder River Basin, but also the largest producer in the United States. *See* Energy Information Administration ("EIA"), *Major U.S. Coal Mines, 2009* (2010), http://www.eia.doe.gov/cneaf/coal/page/acr/table9.html (last accessed Nov. 17, 2011). In 2009 it was reported that the North Antelope Rochelle coal mine produced 98,279,377 tons of coal. *Id*. It is unclear how the production capacity of the North Antelope Rochelle coal mine could be replaced given that no other mines are producing as much coal. It is further difficult to understand the basis for the Supervisor's assertion in light of the fact that the Powder River Basin produces more coal than any other region of the country and has for a number of years. In 2009, the region produced a record 455,503,000 tons of coal, 1.25 times more coal than the entire Appalachian Region of the United States and more than three times the amount of coal produced by the rest of Western United States. *See* EIA, *Coal Production and Number of Mines by State and Mine Type* (2010), http://www.eia.doe.gov/cneaf/coal/page/acr/tables2.html (last accessed Nov. 17, 2011). The North Antelope Rochelle coal mine produced more than twenty-one percent of the of the Powder River Basin's total coal production. It strains credulity to assume that more than twenty-one percent of the coal produced in the largest coal producing region in the country could simply be replaced. Simply put, the Supervisor's "runs counter to the evidence before the agency." *Motor Veh. Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

The Supervisor's position is especially arbitrary because it ignores the cumulative effects of consenting to the North Porcupine LBA together with other pending lease by applications in the Powder River Basin. As the Supervisor states in his ROD, "Including the North Porcupine Field LBA tract there are currently 12 pending LBAs in the Wyoming portion of the PRB. As applied for, the pending coal lease applications include approximately 34,571 acres and 3.722 billion tons of Federal coal." ROD at 35. On a cumulative basis, there is no way the Supervisor could reasonably assert that the coal from the North Porcupine LBA, together with the 3.722 billion tons proposed through the 12 pending lease by applications in the Powder River Basin, would simply be "replaced" by coal from other regions. The total amount of coal to be leased—nearly four billion tons—is more than five times the total amount of coal produced outside the Powder River Basin in 2009. *See* EIA, *Coal Production and Number of Mines by State and Mine Type* (2010), http://www.eia.doe.gov/cneaf/coal/page/acr/table9.html (last accessed Nov. 17, 2011).

Moreover, the Supervisor cannot ignore his duty to analyze impacts simply because he believes similar impacts may occur from other similar activities. This fundamentally undermines the USFS's duties under NEPA, which requires a hard look at the impacts of the major Federal action proposed for authorization, including indirect and cumulative impacts. Simply because another activity may pose similar impacts does not let the USFS off the hook in terms of responsibility for its own actions. This is particularly true here, where, with the exception of the 12 pending coal lease by applications in the Powder River Basin, ***there does not appear to be any single action likely to be responsible for more CO_2 emissions in the United States***.

Tellingly, the Supervisor's flawed logic is underscored by the fact that coal from the Powder River Basin of Wyoming produces more CO_2 emissions on average than virtually every other coal type mined in the United States. According to a report by the EIA, subbituminous coals from the Powder River Basin release on average 212.7 pounds of CO_2 per million Btus. *See* Hong, B.D. and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," EIA, *Quarterly Coal Report, January—April 1994*, DOE/EIA-0121 (94/Q1) (Aug. 1994), *available at* http://205.254.135.24/cneaf/coal/quarterly/co2_article/co2.html (last accessed Nov. 17, 2011). This report is attached as Exhibit 7. Yet bituminous coals produced in the Appalachian and Interior coal producing regions, which according to the EIA is the primary coal type produced in these regions (*see* EIA, *Coal Production and Number of Mines by State and Coal Rank* (2010), http://www.eia.gov/cneaf/coal/page/acr/table6.html (last accessed Nov. 17, 2011)), release on average only a little more than 200 pounds of CO_2 per million Btus.[13] For instance, bituminous coal from West Virginia produces on average 207.1 pounds of CO_2 per million Btus. Compared to coal from the Powder River Basin, other coal types produced in other parts of the country therefore produce fewer CO_2 emissions when burned. Indeed, based on the BLM's assessment that coal from the Powder River Basin averages 8,600 Btus per ton of coal (*see* FEIS at 4-136), a comparable amount (i.e., 309,700,000 tons) of West Virginia bituminous coal would release 500,397,893 metric tons of CO_2 when burned, nearly 13 million metric tons less than are projected to be released by coal from the North Porcupine LBA.[14, 15]

Thus, even if the coal proposed to be leased under the North Porcupine LBA, or all pending LBAs in the Powder River Basin, could reasonably be replaced, all indications are that such an outcome could actually produce fewer CO_2 emissions. Although there is no support for the Supervisor's assertion that coal production is as fluid as he believes, even assuming he may be correct, he fails to analyze the fact that Powder River Basin coal releases more CO_2 emissions when burned than other types of coal produced in the United States, in particular bituminous coals from the Appalachian and Interior coal producing regions. This further highlights the flaws in his analysis and ROD. It further underscores the fact that the USFS, simply by denying the North Porcupine LBA, could actually reduce CO_2 emissions within the United States.

The Supervisor's unsupported, and indeed contradictory, assertion that the CO_2 emissions simply would be "replaced" by other coal sources if the North Porcupine LBA was not issued underscores the failure of the USFS to assess the significance of the CO_2 emissions. NEPA regulations clearly require not only an analysis of impacts, but also an assessment of the significance of indirect impacts. *See* 40 C.F.R. § 1502.16(b). Under NEPA, significance is defined in terms of "context" and "intensity." *See* 40 C.F.R. § 1508.27. In this case, the Wright

[13] Even other subbituminous coals, including subbituminous coal from Iowa, New Mexico, Oregon, Utah, and Washington produce fewer CO_2 emissions on a per million Btu basis according to the EIA report.

[14] This assumes that the Btu content of West Virginia bituminous coal is the same as Powder River Basin subbituminous coal. However, the Btu content of bituminous coal is higher than subbituminous. *See* EIA, *Annual Coal Report, 2009*, DOE-EIA-0584 (2009) at 67 (noting average Btu content of bituminous coal in the U.S. is 24 million Btus per ton) and 72 (noting average Btu content of subbituminous coal in the U.S. is 17-18 million Btus per ton), *available at* http://www.eia.gov/cneaf/coal/page/acr/acr.pdf (last accessed Nov. 17, 2011). This means that fewer tons of West Virginia bituminous coal than Powder River Basin sibbituminous coal are needed to generate the same amount of energy. This means that total CO_2 emissions on a per ton basis would actually be much lower for West Virginia bituminous coal, or any bituminous coal for that matter, than Powder River Basin subbituminous coal.

[15] 13 million metric tons is not insignificant. According to the EPA, this equals the total annual CO_2 emissions from 3.1 coal-fired power plants. *See* EPA, *Greenhouse Gas Equivalencies Calculator*, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results (last accessed Nov. 17, 2011).

Area Coal FEIS did not at all assess the significance of CO_2 emissions associated with the North Porcupine LBA, further undermining the Agency's implication that CO_2 emissions from the North Porcupine LBA do not matter.

The failure to assess significance is particularly troublesome in light of context and intensity of the CO_2 emissions associated with the North Porcupine LBA. As already explained, the level of CO_2 emissions appears to be significant in a number of regards, both in terms of context and intensity. Although the FEIS asserted it was "not possible" to project potential CO_2 emissions, the FEIS does disclose that the North Porcupine LBA will contribute to an increase in the amount of CO_2 emissions associated with the combustion of Powder River Basin coal. Coupled with the facts that the Powder River Basin is already responsible for more CO_2 emissions than any other region of the United States and that Powder River Basin subbituminous coal produces more CO_2 emissions when burned than other types of coal, this is certainly not an insignificant consequence. Indeed, taking into account the impacts of past, present, and reasonably foreseeable coal mining and coal combustion, we are hard pressed to think of any USFS decision that would result in such a large amount of CO_2 emissions.

The context of the associated CO_2 emissions bolsters our concerns and can be summed up this way: The North Porcupine LBA would maintain the Powder River Basin as the leading source of coal for coal-fired power plants and the leading source of CO_2 in the United States. The significance of the North Porcupine LBA was not assessed in this context, further demonstrating that the Supervisor failed to comply with NEPA.

Ultimately, not only did the Supervisor fail to adequately analyze the CO_2 emissions associated with the North Porcupine LBA, he also failed to assess their significance, in violation of NEPA. The failure to analyze and assess such impacts fatally flaws his decision to consent to the North Porcupine LBA.

B. The Supervisor Failed to Analyze and Assess the Potentially Significant Climate Change Impacts of the North Porcupine LBA

Our second concern is over the failure of the Supervisor to analyze and assess how the direct, indirect, and cumulative greenhouse gas emissions associated with the North Porcupine LBA will influence global climate change. As the Supervisor indicates in his ROD, it can be assumed that the release of greenhouse gases associated with the North Porcupine LBA will contribute to climate change. *See e.g.* ROD at 29. Furthermore, the Wright Area Coal FEIS does generally outline the effects associated with global climate change. *See* FEIS at 4-130 to 4-134. Unfortunately, the Supervisor made no attempt to analyze and assess such impacts in relation to the North Porcupine LBA.

The Wright Area Coal FEIS asserts that, "given the state of the science, it is impossible to determine what effect any given amount of GHG emissions resulting from an activity might have on the phenomena of global warming, climate change or the environmental effects stemming from it." FEIS at 4-143. We are rightfully skeptical of this assertion, particularly in light of BLM statements that, "Reducing human-caused GHG [greenhouse gas] emissions would help to lessen any harmful effects that they may be causing to global climate." Exhibit 5, BLM North

Porcupine ROD at 8. Indeed, neither the FEIS nor the Supervisor's ROD cite nor present information or analysis demonstrating that the "state of the science" is such that an analysis of climate change impacts is impossible for the North Porcupine LBA.

We are further skeptical given that the USFS itself has noted that, although there may be uncertainty associated with climate change impacts, "based on climate change science, we can recognize the relative potential of some types of proposals and alternatives to affect or influence climate change and therefore provide qualitative analysis to help inform project decisions." USFS, *Climate Change Considerations in Project Level NEPA Analysis* (Jan. 13, 2009) at 6-7, *available at* http://www.fs.fed.us/emc/nepa/climate_change/includes/cc_nepa_guidance.pdf (last accessed Nov. 17, 2011). This guidance is attached as Exhibit 8. In light of the fact that the USFS Chief himself has recognized global climate change as a significant threat to NFS resources, the Supervisor's indirect assertion that it is "impossible" to analyze or assess climate change impacts seems all the more unjustified.

However, even assuming the Supervisor may be correct, his assertion does not satisfy NEPA's disclosure requirements. NEPA's implementing regulations require that the USFS "evaluate reasonably foreseeable significant adverse effects on the human environment," even where information relevant to making this evaluation is "incomplete or unavailable." 40 C.F.R. § 1502.22. If, as the FEIS asserts, it is "impossible" to analyze climate impacts, the USFS must clearly show that the information is "lacking" by providing what credible scientific information it does have on such reasonably foreseeable impacts and making an effort to analyze these impacts based on this information. *Id*. Specifically, even if it cannot obtain complete information about those effects, "the agency shall [still] include in the environmental impact statement":

> (1) A statement that such information is incomplete or unavailable; (2) a statement of the relevance of the incomplete or unavailable information to evaluating reasonably foreseeable significant adverse impacts on the human environment; (3) a summary of existing credible scientific evidence which is relevant to evaluating the reasonably foreseeable significant adverse impacts on the human environment, and (4) the agency's evaluation of such impacts based upon theoretical approaches or research methods generally accepted in the scientific community.

40 C.F.R. § 1502.22(b). Under this section, reasonably foreseeable impacts "include[] impacts which have catastrophic consequences, even if their probability of occurrence is low, provided that the analysis of the impacts is supported by credible scientific evidence, is not based on pure conjecture, and is within the rule of reason." *Id*.

Despite the Supervisor's claim that the USFS is unable to analyze and assess the climate change impacts associated with the North Porcupine LBA, nowhere in the Wright Area Coal FEIS or the ROD is it apparent that the requirements of 40 C.F.R. § 1502.22 have been met. In fact, neither document even references 40 C.F.R. § 1502.22. Of particular concern is that the Supervisor made no effort to evaluate climate change impacts using theoretical approaches or research methods generally accepted by the scientific community in accordance with 40 C.F.R. §

1502.22(b)(4). The Supervisor did not even prepare a qualitative assessment of global climate change impacts, which could have at least provided information to the public and the decisionmaker regarding the potentially significant impacts and seems justified in light of the USFS's own guidance on the matter. Put simply, the Supervisor made no effort to evaluate climate change impacts using the credible scientific information available to the USFS. In other words, he made no effort to do the best he could with the information he had, as 40 C.F.R. § 1502.22 requires.

This failure to comply with NEPA is particularly troublesome given the apparent significance of the indirect and cumulative greenhouse gas emissions associated with the North Porcupine LBA, as well as the Wright Area Coal FEIS's general disclosure regarding the impacts of climate change. As it stands, the Supervisor failed to comply with NEPA with regards to the analysis and assessment of the climate change impacts associated with the North Porcupine LBA.

C. The Supervisor Failed to Analyze in Detail a Range of Alternatives to Address Greenhouse Gas Emissions and Climate Change Impacts

In addition to failing to adequately analyze and assess global climate change impacts, the Supervisor also failed to analyze in detail a range of alternatives to address the indirect and cumulative CO_2 emissions and the likely climate change impacts of the North Porcupine LBA. In particular, the Supervisor failed to consider alternatives to mitigate adverse climate change impacts in accordance with 40 C.F.R. §§ 1502.14(f) and 1502.16(h), including alternatives raised by Appellant WildEarth Guardians in comments on both the Wright Area Coal DEIS and FEIS, which were extensively referenced by the Appellants in their comments on the USFS's proposed consent to the North Porcupine LBA. This failure is especially problematic because prior to consenting to a coal lease, the USFS is explicitly obligated under the FSM to analyze a "[r]ange of alternatives available for operations and land uses and for environmental protection." FSM 2822.41(11).

It is unclear exactly why the Supervisor did not consider in detail alternatives to address significant impacts and public concern related to greenhouse gas emissions. In his ROD, the Supervisor did not assert that such alternatives were outside the purpose and need for the project. Furthermore, the Supervisor did not assert that such alternatives were speculative. In fact, it does not appear as if the USFS even responded to Appellants' comments at all. In fact, in the RTC, the USFS simply references the FEIS, asserting that, "This comment was previously brought up throughout the process and addressed in the formal response to comments on both the DEIS and FEIS." RTC at 67. Indeed, although the BLM provided a response to Appellants' comments regarding the range of alternatives in the Wright Area Coal DEIS (*see* FEIS, Appendix I), there is no corollary response to comments from the USFS included in the FEIS or in the Supervisor's ROD.[16]

On the one hand, this seems to indicate that the Supervisor did not even review

[16] In fact, the title of Appendix I is, "Draft EIS Comment Letters, ***BLM Responses***, and Hearing Summary." Wright Area Coal FEIS, Appendix I at 1 (emphasis added). There is no mention in Appendix I, or anywhere else in the Wright Area Coal FEIS for that matter, of any explicit USFS response to comments.

Appellants comments and therefore made no effort to meaningfully respond to concerns over the range of alternatives. This seems to squarely violate NEPA's requirement that the USFS respond to comments in accordance with 40 C.F.R. § 1503.4. On the other hand, even assuming that the Supervisor simply deferred to the BLM's response to comments on the range of alternatives issue, even this response falls short of complying with NEPA. We respond to the BLM's arguments below.

The BLM responds to Appellant WildEarth Guardians' proposed alternatives in Comment Response 2 and, to a lesser degree, Comment Response 5. *See* FEIS, Appendix I at BLM Response to Comments, 2 and 4-5. This response to comments, however, does not actually specifically address any of the alternatives proposed by WildEarth Guardians. Instead, the BLM seems to proffer two extremely generalized arguments against any alternative that would address global climate changes impacts: 1) The Agency analyzed a range of reasonable alternatives and 2) BLM "does not regulate" GHG emissions. Both of these arguments fail to provide a rational justification for not considering in detail the alternatives proposed by WildEarth Guardians.

To begin with, BLM cites its Handbook at H-1790-1 as support for its assertion that it considered in detail a range of reasonable alternatives. The BLM's NEPA handbook, however, provides no justification for the USFS to violate NEPA with regards to considering a range of reasonable alternatives.[17] In this case, BLM did not explain how Appellant WildEarth Guardians' proposed alternatives were speculative, unreasonable, or otherwise not consistent with the purpose and need for the proposed action.

With regards to regulating greenhouse gas emissions, Appellants nowhere asked the BLM to regulate greenhouse gas emissions. Instead, Appellants requested that the BLM consider imposing stipulations that would address the global climate change impacts of the North Porcupine LBA. For example, WildEarth Guardians requested that the BLM limit the tonnage and acreage of the lease, an action that BLM has complete authority to regulate. Thus, BLM grossly misconstrued WildEarth Guardians' comments and in doing so, overlooked reasonable opportunities to address greenhouse gas emissions associated with the North Porcupine LBA.

In comments on the Wright Area DEIS, WildEarth Guardians requested, in detail and with explanation, that the BLM thoroughly analyze the following alternatives:

- Alternatives with varied tonnage and acreage limits to leases so that changes can be made in the future to respond to GHG emissions regulation

- An alternative that establishes a renewable energy fund to spur solar and wind development in Wyoming to mitigate carbon emissions and to create long-term jobs.

- An alternative that requires the coal lessees to purchase carbon offsets.

[17] Notably, the BLM Handbook does not guide USFS actions.

- An alternative that would require that all carbon emissions from Wright Area coal used for electricity generation be captured and sequestered geologically.

- An alternative that establishes a Renewable Energy Standard ("RES") for coal mine operators.

- An alternative that would require all mine vehicles to be run on alternative fuels.

WildEarth Guardians' Comments on Wright Area Coal DEIS at 12-14. Every single one of these alternatives is squarely within the authority of the BLM to implement. Indeed, BLM has a duty to impose any stipulations that are "deem[ed] appropriate." 43 C.F.R. § 3475.1. In light of the fact that the BLM has a nondiscretionary duty to reject any LBA that "for environmental or other sufficient reasons, would be contrary to the public interest" (43 C.F.R. § 3425.1-8(a)(3), it is clear that the Agency has broad authority to impose stipulations to safeguard the environment. This is underscored by the fact that the BLM has the authority to "prescribe additional terms and conditions [] to safeguard the public welfare." 43 C.F.R. § 3420.4-2(b). The alternatives proposed by WildEarth Guardians could have been adopted as lease stipulations to ensure greater protection of the Earth's climate, which clearly is a matter of environmental protection and public welfare. The BLM's failure to meaningfully analyze the merits of these alternatives, or to even accept that the Agency has a duty to safeguard the environment at the leasing stage, is a clear violation of NEPA. Thus, the USFS's deference to the BLM's response to comments is further indicative of a violation of NEPA and the Supervisor's ROD must be reversed.

IV. The Supervisor Failed to Adequately Analyze and Assess Air Quality Impacts

The USFS further failed to adequately analyze and assess air quality impacts associated with development of the North Porcupine LBA in accordance with NEPA. This oversight is significant given not only the public health and welfare ramifications of air pollution, but given the Wright Area Coal FEIS's own disclosure that development of the North Porcupine LBA would significantly exacerbate air quality impacts.

The USFS not only has authority to address air quality impacts, but a duty. Under the TBNG Grassland Plan, the Agency is required to "[c]onduct all land management activities in such a manner as to comply with all applicable federal, state, and local air-quality standards and regulations" and "[e]nsure emissions from projects on the Grassland and forest management activities are within Class I or Class II ranges" (*see* Grassland Plan at 1-9, Physical Resources, Air Standards 1 and 3). Thus, the failure to adequate analyze and assess air quality impacts renders the Supervisor's ROD fatally flawed. Our specific concerns are as follows:

A. Ozone

Ozone is a harmful gas for which the EPA has established NAAQS in order to protect public health. *See* 40 C.F.R. § 50.15. The Wright Area Coal FEIS explains:

> Potential health risks associated with inhalation of ground level O_3 [ozone] [] include acute respiratory problems, aggravated asthma, decreases in lung capacity in some healthy adults, inflammation of lung tissue, respiratory-related hospital admissions and emergency room visits, and increased susceptibility to respiratory illnesses, including bronchitis and pneumonia (EPA 2007b).

FEIS at 3-81. The Wright Area Coal FEIS states, "Ground level ozone is not emitted directly into the air, but is created by chemical reactions between NO_x [nitrogen oxides] and VOCs [volatile organic compounds] on the presence of sunlight." *Id.* at 3-49.

Currently, the NAAQS limit ozone concentrations to no more than 0.075 parts per million over an eight hour period (often referred to as the "8-hour ozone NAAQS"). According to the EPA, an exceedance of the standard occurs whenever ambient ozone concentrations reach 0.076 parts per million or higher and a violation occurs whenever the three year average of the fourth highest annual 8-hour ozone concentrations is 0.076 parts per million or higher. *See* 40 C.F.R. § 50.15.[18]

In its comments, Appellants raised concerns over the impacts of the North Porcupine LBA to ambient 8-hour ozone concentrations in the region. Unfortunately, neither the BLM nor the USFS prepared any analysis or assessment of the impacts of the North Porcupine LBA to ambient ozone. In its RTC, the USFS simply asserts that, "Ozone was fully considered and analyzed throughout the document (FEIS)." RTC at 67-68. However, this was not the case. There was no analysis in the FEIS. The Wright Area Coal FEIS in fact seemed to imply that ozone is not an issue with regards to the LBA. However, this is contradicted in a number of regards and the USFS's assertion that its obligations to analyze and assess ozone impacts under NEPA are unfounded.

Indeed, the FEIS appeared to assert that the region where the North Porcupine LBA is located is in compliance with the 8-hour ozone NAAQS, and therefore an analysis or assessment of direct, indirect, and cumulative impacts is not warranted. This assertion ignores the fact that numerous exceedances of the NAAQS have occurred in the region, and that the region is not only nearly violating the NAAQS, but will most likely violate new ozone NAAQS that have been proposed by the EPA.

Two monitors are in operation in Campbell County, one in the TBNG and the other in southern Campbell County. According to data from these monitors, ozone concentrations in Campbell County, Wyoming have exceeded the current 8-hour ozone NAAQS on 16 occasions since 2001. *See* table below. According to this data, 8-hour ozone concentrations have peaked as high as 0.088 parts per million. According to this data, the three year average of the fourth highest annual 8-hour ozone readings for the years 2008-2010 is 0.061 parts per million at the

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[18] Contrary to BLM's assertion otherwise in its FEIS, an exceedance of the ozone NAAQS does not occur only when the fourth highest daily maximum value is above the standard. Anytime the NAAQS are exceeded is considered an exceedance. An exceedance of the NAAQS is considered to reflect poor air quality and as such, EPA requires that health warnings be issued to the general public whenever an exceedance occurs or is projected to occur. *See* 40 C.F.R. § 58, Appendix G, disclosing that an exceedance of the ozone NAAQS should lead to a categorization of "unhealthy."

South Campbell County Monitor and 0.066 parts per million at the TBNG monitor.

Number of days above the current ozone NAAQS at Campbell County, Wyoming Ozone Monitors. Peak ozone concentration in parentheses (in parts per million).[19]

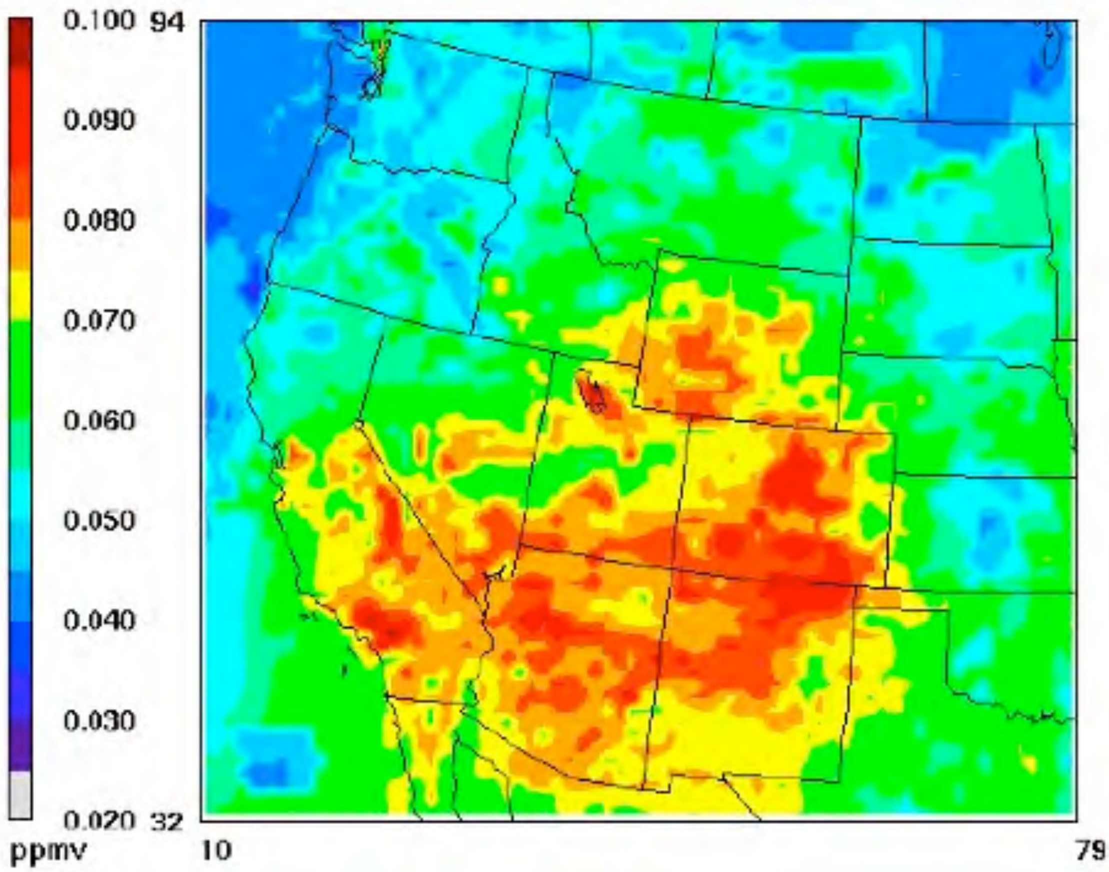
Monitor	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Thunder Basin National Grassland	0	1 (0.088)	2 (0.085	0	0	0	3 (0.081)	3 (0.078)	0	0
South Campbell County	--	--	6 (0.083)	0	0	0	1 (0.076)	0	0	0

In fact, just since 2005, EPA reports that there have been more than 200 days of "moderate" air quality based on 8-hour ozone concentrations monitored in Campbell County, Wyoming and seven days of air quality deemed "Unhealthy for Sensitive Groups" based on these same ozone concentrations. *See* U.S. EPA, *Daily Ozone AQI* Levels, 2005-2010, Campbell County, Wyoming, *available at* http://www.epa.gov/cgi-bin/htmSQL/mxplorer/trend_tile.hsql?msaorcountyName=msacode&msaorcountyValue=-1&poll=44201&county=-1&msa=-1&sy=2010&flag=Y&_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas (last accessed Nov. 17, 2011). This data is attached as Exhibit 9. Not surprisingly, even the EPA itself has commented that it is "concerned with measured ozone concentrations in the surrounding area." *See* U.S. EPA, Comments on Wright Area Coal DEIS (Sept. 10, 2009) at 2, *available at* http://yosemite.epa.gov/oeca/webeis.nsf/(PDFView)/20090209/$file/20090209.PDF?OpenElement (last accessed Nov. 17, 2011). These comments are attached as Exhibit 10.

The likelihood of high ozone levels in the region is consistent with recent modeling prepared for the Western Regional Air Partnership ("WRAP"), which indicates that large areas of the Rocky Mountain West, including northeastern Wyoming, are projected to exceed and/or violate the ozone NAAQS by 2018. In 2008 presentation given at a WRAP Technical Analysis Meeting in Denver, Colorado, it was reported that the modeling "predicts exceedance of the 8-hour average ozone standard in much of the southwestern US, mostly in spring." Tonnesen, G.,

[19] *See* EPA, *Monitor Values Report, Campbell County, Wyoming, 2001-2008*, *available at* http://iaspub.epa.gov/airsdata/adaqs.monvals?geotype=co&geocode=56005+56009&geoinfo=co~56005+56009~Campbell+Co%2C+Converse+Co%2C+Wyoming&pol=O3&year=2008+2007+2006+2005+2004+2003+2002+2001+2000&fld=monid&fld=siteid&fld=address&fld=city&fld=county&fld=stabbr&fld=regn&rpp=25 (last accessed Aug. 25, 2011); *see also*, EPA, *AirExplorer Query, Campbell County, Wyoming, 2009 and 2010*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=&msaorcountyValue=&poll=44201&county=56005&site=-1&msa=-1&state=-1&sy=2010&flag=Y&query=view&_debug=2&_service=data&_program=dataprog.query_daily3P_dm.sas and http://www.epa.gov/cgi-bin/broker?msaorcountyName=&msaorcountyValue=&poll=44201&county=56005&site=-1&msa=-1&state=-1&sy=2010&flag=Y&query=view&_debug=2&_service=data&_program=dataprog.query_daily3P_dm.sas (last accessed Aug. 25, 2011).

Z. Wang, M. Omary, C. Chien, Z. Adelman, and R. Morris, et al., *Review of Ozone Performance in WRAP Modeling and Relevance to Future Regional Ozone Planning*, presentation given at WRAP Technical Analysis Meeting (July 30, 2008) at unnumbered slide 30, *available at* http://wrapair.org/forums/toc/meetings/080729m/RMC_Denver_OzoneMPE_Final2.pdf (last accessed Aug. 25, 2011). This presentation is attached as Exhibit 11. The image below from the WRAP presentation shows areas projected to exceed and/or violate the current and future ozone NAAQS.



Projected 2018 annual fourth maximum ozone concentrations. Orange and red indicate exceedances and/or violations of the ozone NAAQS of 0.075 parts per million. *See* Exhibit 11 at unnumbered slide 28.

The likelihood of high ozone in the area of the North Porcupine LBA is also underscored by the projected NO_x emissions, which the Wright Area Coal FEIS indicates is a precursor to ozone. According to the BLM, NO_x emissions are estimated to be as high as 3,856 tons/year in 2017 at the North Antelope Rochelle coal mine. To put this into perspective, this as much NO_x pollution as is released annually by more than 201,884 passenger vehicles.[20]

[20] According to EPA, an average passenger vehicle releases 38.2 pounds of NOx annually. *See* http://www.epa.gov/otaq/consumer/f00013.htm (last accessed Nov. 17, 2011).

Although USFS may claim that the State of Wyoming will address any potentially significant direct, indirect, and cumulative ozone impacts, this claim is misplaced. To begin with, no modeling has been prepared by the State of Wyoming to assure compliance with the eight-hour ozone NAAQS. In fact, the State of Wyoming does not even require or otherwise prepare ozone modeling prior to issuing air permits for coal mining operations in the Powder River Basin. According to the Wyoming Department of Environmental Quality, coal companies only model their impacts to the annual particulate matter and annual nitrogen dioxide NAAQS prior to receiving an air quality permit. *See* Wyoming DEQ, *PRB Coal Mine Permitting Guidance* (February 27, 2006), *available at* http://deq.state.wy.us/aqd/Oil%20and%20Gas/PRB%20Permit%20Guidance_4.pdf (last accessed Nov. 17, 2011). No other air quality modeling or analysis is required. Thus the USFS would be incorrect to argue that the State of Wyoming will analyze and assess ozone impacts.[21]

It is true that violation of the 8-hour ozone NAAQS has yet to occur, but the duty to analyze and assess air quality impacts does not hinge upon an area falling into violation of ambient air quality standards. This duty is all the more imperative in the Powder River Basin in light of signs that the region could violate the NAAQS as a result of the North Porcupine LBA. These signs include monitored exceedances of the NAAQS, the fact that the three year average of the fourth highest annual eight hour ozone concentrations at the Thunder Basin National Grassland ozone monitor is 0.066 parts per million, the fact that regional modeling projects exceedances and/or violations of the ozone NAAQS in the near future, and the fact that the region will likely violate the EPA's proposed revision to the ozone NAAQS. Even the EPA has commented that it is "particularly important [to use a] current state-of-science photochemical grid model [whenever elevated ozone levels are recorded]." *See* U.S. EPA, Comments on Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Sublette County, Wyoming (February 14, 2008) at 3, *available at* http://www.wyomingoutdoorcouncil.org/html/what_we_do/air_quality/pdfs/EPA%20EU3%20Letter%20on%20Revised%20Draft%20SEIS.pdf (last accessed Nov. 17, 2011). This comment letter is attached as Exhibit 12.

In this case, the USFS did not even explain why a photochemical grid model was not necessary, other than to apparently defer to the BLM's assertion that the region is not currently violating the NAAQS. This is bizarre logic. The point of NEPA is to address and avoid potentially significant impacts before they occur, not wait for them to occur before taking action.

In light of this, the USFS's failure to analyze and assess the impacts of the North Porcupine LBA to ambient ozone concentrations represents a fatal flaw in the agency's analysis and ROD and a fundamental violation of NEPA.

B. Nitrogen Dioxide

The USFS failed to analyze and assess the potentially significant impacts to the current

[21] We are further concerned with any claim that the State of Wyoming will adequately analyze and assess air quality impacts in light of the fact that NEPA does not apply to state actions.

NAAQS for nitrogen dioxide. On February 9, 2010, the EPA finalized revisions to the nitrogen dioxide NAAQS, supplementing the current annual standard of 53 parts per billion with a 1-hour standard of 100 parts per billion. *See* 75 Fed. Reg. 6474-6537 (Feb. 9, 2010). These NAAQS were originally proposed on July 15, 2009. *See* 74 Fed. Reg. 34404-34466 (July 15, 2009). These NAAQS became effective on April 12, 2010.

Nowhere did the USFS attempt to analyze the degree to which the North Porcupine LBA would affect nitrogen dioxide concentrations on an hourly basis. In fact, the RTC simply states, "NO2 was fully considered and analyzed throughout the document (FEIS)." RTC at 68. This is simply not the case.

Although the Wright Area Coal FEIS notes that in 2010, the EPA set a new 1-hour NO_2 standard, there is no analysis of the LBA to concentrations of this harmful pollutant. This is disconcerting not only in light of what the NAAQS require, but in light of the Wright Area Coal FEIS's disclosure regarding the danger of nitrogen dioxide. As the FEIS states, "[N]itrogen dioxide (NO_2) [] is a highly reactive, reddish brown gas that is heavier than air and has a pungent odor. NO_2 is by far the most toxic of several species of NO_x." FEIS at 3-78. The BLM continues to note that nitrogen dioxide "may cause significant toxicity because of its ability to form nitric acid with water in the eye, lung mucous membranes, and skin," "may cause death by damaging the pulmonary system," and "may exacerbate pre-existing respiratory conditions, or increase the incidence of respiratory infections." *Id*. The BLM discloses, "there is concern about the potential health risk associated with short-term exposure to NO_2 from blasting emission." FEIS at 3-81.

The failure to analyze and assess impacts of the North Porcupine LBA to 1-hour NO_2 concentrations is further troubling because according to the BLM, on a cumulative basis, there are violations occurring in the Powder River Basin that are projected to worsen. Modeling prepared for the BLM as part of the Powder River Basin Coal Review shows that background 1-hour NO_2 concentrations in Montana are at 217.43 parts per billion, already more than twice the NAAQS. *See* AECOM, *Update of Task 3A Report for the Powder River Basin Coal Review Cumulative Air Quality Effects for 2020*, Prepared for Bureau of Land Management, High Plains District Office, Wyoming State Office, and Miles City Field Office (Dec. 2009) at ES-6, *available at* http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/prbdocs/coalreview/task_3a-2020.html (last accessed Nov. 17, 2011). This report is attached as Exhibit 13. As the table below shows, by 2020, these concentrations are expected to worsen to as high as 235.35 parts per billion. As the Wright Area Coal FEIS itself notes, "the modeling results indicate that the 1-hour NO_2 concentrations at Montana near-field receptors for 2020 would exceed EPA's new 1-hour NAAQS (0.001 [parts per million] or 188.1 [micrograms/cubic meter]." FEIS at 4-48. Unfortunately, the FEIS makes no effort to analyze cumulative NO_2 impacts in the Wyoming portion of the Powder River Basin.

Baseline and Projected Levels of 1-hour NO_2.[22]

NAAQS	Standard	2004 Baseline Concentration	2020 Lower Coal Development Scenario	2020 Upper Coal Development Scenario
1-hour NO_2	100 ppb	217.43 ppb	233.97 ppb	235.35 ppb

The Wright Area Coal FEIS may assert that voluntary mitigation measures will address any potentially significant short-term NO_2 impacts from the North Porcupine LBA, but there is no analysis, including any air quality analysis, or assessment to support such an assertion. Indeed, there is no assessment of the effectiveness of any mitigation measures, voluntary or otherwise, to address short-term nitrogen dioxide impacts in the context of the NAAQS. Furthermore, by all measures, any mitigation measures in the FEIS will fail. As the FEIS notes, on a cumulative basis, hourly NO_2 concentrations will exceed the NAAQS. Furthermore, to the extent that the FEIS relies on voluntary measures to address any potentially significant nitrogen dioxide impacts, such measures cannot serve to mitigate impacts given that they are unenforceable.

Although it may be claimed that the State of Wyoming will address any potentially significant direct, indirect, and cumulative 1-hour NO_2 impacts, this claim is misplaced. To begin with, no modeling has been prepared by the State of Wyoming to assure compliance with the 1-hour NO_2 NAAQS. In fact, the State of Wyoming does not even require or otherwise prepare NO_2 modeling prior to issuing air permits for coal mining operations in the Powder River Basin. As explained already, the Wyoming Department of Environmental Quality only requires coal companies to model impacts to the annual particulate matter and annual NO_2 NAAQS prior to receiving an air quality permit. *See* Wyoming DEQ, PRB Coal Mine Permitting Guidance. No other air quality modeling or analysis is required, thus it would be incorrect to assert that the State of Wyoming will analyze and assess 1-hour NO_2 impacts.[23]

C. $PM_{2.5}$ NAAQS

The USFS failed to analyze and assess the potentially significant impacts to the current NAAQS for particulate matter less than 2.5 microns in diameter ("$PM_{2.5}$"). The current NAAQS limit annual $PM_{2.5}$ concentrations to no more than 15 micrograms/cubic meter and 24-hour concentrations to no more than 35 micrograms/cubic meter. *See* FEIS at 3-50. This raises serious concerns that the USFS failed to adequately analyze and assess the public health impacts of the North Porcupine LBA. As the Wright Area Coal FEIS notes, the $PM_{2.5}$ NAAQS were established "based on their link to serious health problems." FEIS at 3-51.

[22] *See* Powder River Basin Coal Review report, Exhibit 13 at ES-6. Data for NO_2 is presented in the report in terms of microgram/cubic meter concentrations. For ease of comparison with the NAAQS, which are expressed in terms of parts per billion, the microgram/cubic meter concentration was converted to parts per billion. Additionally, the 1-hour NO_2 concentrations were only modeled for the Montana portion of the Powder River Basin.

[23] Furthermore, as mentioned in the ozone discussion above, NEPA does not apply to state actions. Thus, any Wyoming Department of Environmental Quality permitting process cannot possibly be relied upon as a substitute for NEPA compliance.

We are particularly concerned that, although the Wright Area Coal FEIS in one section seems to imply that current $PM_{2.5}$ concentrations are not exceeding the NAAQS, the cumulative effects analysis indicates that current background $PM_{2.5}$ concentrations ***are exceeding*** the 24-hour NAAQS ***and are projected to exceed*** both the annual and 24-hour NAAQS. *Contrast* FEIS at 3-50 with FEIS at 4-47. Either way, nowhere in the FEIS does the USFS analyze the degree to which the North Porcupine LBA will affect annual and 24-hour $PM_{2.5}$ concentrations or assess the significance of these impacts. In fact, the Supervisor's ROD does not even mention $PM_{2.5}$.

The failure to analyze and assess impacts of the North Porcupine LBA to annual and 24-hour $PM_{2.5}$ concentrations is particularly troubling in light of the current and projected exceedances. Modeling prepared for the BLM as part of the Powder River Basin Coal Review shows that background 24-hour $PM_{2.5}$ concentrations are, on a cumulative basis, already at 87.6 micrograms/cubic meter, more than twice the NAAQS. *See* Powder River Basin Coal Review report, Exhibit 13 at ES-6. As the table below shows, by 2020, these concentrations are expected to worsen and exceedances of both the annual and 24-hour NAAQS are projected under both a low and upper coal development scenario. Furthermore, the modeling shows that coal mines and coal-related activities are going to be significant contributors to annual and 24-hour $PM_{2.5}$ concentrations. *Id*. at 3-4.

Baseline and Projected Levels of $PM_{2.5}$.[24]

NAAQS	Standard	2004 Baseline Concentration	2020 Lower Coal Development Scenario	2020 Upper Coal Development Scenario
Annual $PM_{2.5}$	15 $\mu g/m^3$	13.4 $\mu g/m^3$	16.3 $\mu g/m^3$	16.3 $\mu g/m^3$
24-hour $PM_{2.5}$	35 $\mu g/m^3$	87.6 $\mu g/m^3$	218.4 $\mu g/m^3$	218.4 $\mu g/m^3$

Finally, although it may again be claimed that the State of Wyoming will address any potentially significant direct, indirect, and cumulative $PM_{2.5}$ impacts, this claim is misplaced. To begin with, no modeling has been prepared by the State of Wyoming to assure compliance with the $PM_{2.5}$ NAAQS. Furthermore, as explained already, the Wyoming Department of Environmental Quality only requires coal companies to model impacts to the annual particulate matter and annual NO_2 NAAQS prior to receiving an air quality permit. *See* Wyoming DEQ, PRB Coal Mine Permitting Guidance. No other air quality modeling or analysis is required, thus it would be incorrect to assert that the State of Wyoming will analyze and assess $PM_{2.5}$ impacts, or that any State process will serve as a reasonable surrogate for the USFS to rely upon to comply with NEPA.[25]

D. $PM_{2.5}$ Increments for Class I Areas

The USFS failed to analyze and assess the potentially significant impacts to the current

[24] *See* Powder River Basin Coal Review report, Exhibit 13 at ES-6.

[25] Furthermore, as mentioned in the ozone discussion above, NEPA does not apply to state actions. Thus, any Wyoming Department of Environmental Quality permitting process cannot possibly be relied upon as a substitute for NEPA compliance.

Class I increments for 24-hour $PM_{2.5}$. Increments are similar to the NAAQS, although they apply based on whether an area is designated as Class I or Class II. In this case, the EPA adopted Class I increments for 24-hour $PM_{2.5}$ on October 20, 2010, limiting concentrations to no more than 2 micrograms/cubic meter. *See* 75 Fed. Reg. 64864-64907.

Despite this, there is no analysis or assessment of the impacts of the North Porcupine LBA to the 24-hour $PM_{2.5}$ increment. In fact, the Wright Area Coal FEIS does not even acknowledge the existence of the 24-hour $PM_{2.5}$ increment *See* FEIS at 3-50. This is disconcerting because again, modeling prepared for the BLM as part of the Powder River Basin Coal Review shows that background 24-hour $PM_{2.5}$ concentrations are, on a cumulative basis, already exceeding the increment in three nearby Class I areas—the Northern Cheyenne Indian Reservation in Montana, Badlands National Park in South Dakota, and Wind Cave National Park also in South Dakota. *See* Powder River Basin Coal Review report, Exhibit 13 at ES-7. As the tables below show, by 2020, background 24-hour $PM_{2.5}$ concentrations are expected to worsen, with exceedances of the increment reported in all three Class I areas under both low and upper coal production scenarios. The modeling also shows that coal mines and coal-related activities are going to be significant contributors to annual and 24-hour $PM_{2.5}$ concentrations. *Id.* at 3-4.

Baseline and Projected Increment Levels, Northern Cheyenne Indian Reservation (MT).[26]

Increment	Standard ($\mu g/m^3$)	2004 Baseline Concentration ($\mu g/m^3$)	2020 Lower Coal Development Scenario ($\mu g/m^3$)	2020 Upper Coal Development Scenario ($\mu g/m^3$)
24-hour $PM_{2.5}$	2	3.4	4.5	4.6

Baseline and Projected Increment Levels, Badlands National Park (SD).

Increment	Standard ($\mu g/m^3$)	2004 Baseline Concentration ($\mu g/m^3$)	2020 Lower Coal Development Scenario ($\mu g/m^3$)	2020 Upper Coal Development Scenario ($\mu g/m^3$)
24-hour $PM_{2.5}$	2	2.1	3.0	3.1

Baseline and Projected Increment Levels, Wind Cave National Park (SD).

Increment	Standard ($\mu g/m^3$)	2004 Baseline Concentration ($\mu g/m^3$)	2020 Lower Coal Development Scenario ($\mu g/m^3$)	2020 Upper Coal Development Scenario ($\mu g/m^3$)
24-hour $PM_{2.5}$	2	3.8	4.6	4.7

The failure of the USFS to analyze and assess impacts to the 24-hour $PM_{2.5}$ increment is

[26] All increment data is presented in the Powder River Basin Coal Review report, Exhibit 13 at ES-7.

especially of concern because the Grassland Plan explicitly requires the Agency to "[e]nsure emissions from projects on the Grassland [] are within Class I [] ranges." Grassland Plan at 1-1-9, Physical Resources, Air Standard 3. Without an analysis of the impacts of the North Porcupine LBA to 24-hour $PM_{2.5}$ increments in Class I areas, the Supervisor has no basis to assert that consent to the North Porcupine LBA will ensure compliance with the Grassland Plan.

E. PM_{10} NAAQS and Increments

Particulate matter less than 10 microns in diameter, or PM_{10}, is a harmful pollutant for which the EPA has established NAAQS and increments in order to protect public health. *See* 40 C.F.R. §§ 50.10 and 52.21(c). The Wright Area Coal FEIS explains:

> Particulates, especially fine particles, have been linked to numerous respiratory related illnesses and can adversely affect individuals with pre-existing heart or lung diseases (EPA 2007a). They are also a major cause of visibility impairment in many parts of the United States. While individual particles cannot be seen with the naked eye, collectively they can appear as black soot, dust clouds, or gray hazes.

FEIS at 3-55-3-66. Currently, the NAAQS limit PM_{10} concentrations to no more than 150 micrograms/cubic meter, although Wyoming ambient air quality standards also limit annual PM_{10} concentrations to no more than 50 micrograms/cubic meter. *See* FEIS at 3-50. The increments limit 24-hour PM_{10} concentrations to no more than 8 micrograms/cubic meter in Class I areas.

In analyzing the impacts of the North Porcupine LBA, the Wright Area Coal FEIS did not overlook the fact that a number of exceedances of the 24-hour PM_{10} NAAQS have occurred in the region of the North Antelope Rochelle coal mine. As the Agency states, "From 2001 through 2006 there were a total of nine exceedances of the 24-hour PM_{10} particulate matter standard associated with the Black Thunder, Jacobs Ranch, and North Antelope Rochelle mines." FEIS at 3-55. Nor did the FEIS deny that the North Porcupine LBA would contribute to future exceedances of the 24-hour PM_{10} NAAQS. As the FEIS, the cumulative impacts of the North Porcupine LBA would include exceedances of the 24-hour PM_{10} NAAQS, leading to concentrations as high as 624.1 micrograms/cubic meter, even under a low production scenario. *See* FEIS at 4-41. This is more than four times the level of the NAAQS. Nor did the FEIS gloss over the fact that exceedances of the 24-hour PM_{10} increments are not only currently occurring in Class I areas, but that exceedances are projected to occur on a cumulative basis in no fewer than three nearby Class I areas. *See* FEIS at 4-50.

Despite these disclosures, the USFS concluded that the North Porcupine LBA would comply with the 24-hour PM_{10} NAAQS and increments. Unfortunately, what the USFS failed to do is prepare any analysis and assessment to support this finding. On the contrary, the analysis and assessment in the FEIS seems to support an entirely opposite conclusion.

The FEIS appears to assert that compliance with State of Wyoming air quality permitting requirements would prevent exceedances of the 24-hour PM_{10} NAAQS and increments. This is a dubious statement, to say the least. Even under current air quality permits, exceedances of the NAAQS are occurring. This is significant because BLM discloses that, "monitoring results have been used in lieu of short-term (24-hour) modeling for assessing short-term coal mining-related impacts in the PRB." FEIS at 3-58. In other words, only monitoring, not modeling, has been used to ensure compliance with the NAAQS. In light of this, there is no indication that future permits will ensure compliance in light of monitored exceedances. This is underscored by the FEIS's own cumulative effects analysis, which shows that exceedances of the 24-hour PM_{10} NAAQS will occur, even at similarly permitted production rates.

Furthermore, as the FEIS clearly demonstrates, exceedances of the 24-hour PM_{10} increments are currently occurring on the Northern Cheyenne Indian Reservation and in Wind Cave National Park. *See* FEIS at 4-50; *see also*, Powder River Basin Coal Review report, Exhibit 13 at ES-7. By 2020, exceedances are projected in these two Class I areas, in addition to Badlands National Park, even under a low coal production scenario. The tables below illustrate the increment exceedances that are occurring and are projected to occur.

Baseline and Projected Increment Levels,
Northern Cheyenne Indian Reservation (MT).[27]

Increment	Standard (µg/m^3)	2004 Baseline Concentration (µg/m^3)	2020 Lower Coal Development Scenario (µg/m^3)	2020 Upper Coal Development Scenario (µg/m^3)
24-hour PM_{10}	8	9.6	12.9	13.2

Baseline and Projected Increment Levels,
Badlands National Park (SD).

Increment	Standard (µg/m^3)	2004 Baseline Concentration (µg/m^3)	2020 Lower Coal Development Scenario (µg/m^3)	2020 Upper Coal Development Scenario (µg/m^3)
24-hour PM_{10}	8	5.9	8.5	8.8

Baseline and Projected Increment Levels,
Wind Cave National Park (SD).

Increment	Standard (µg/m^3)	2004 Baseline Concentration (µg/m^3)	2020 Lower Coal Development Scenario (µg/m^3)	2020 Upper Coal Development Scenario (µg/m^3)
24-hour PM_{10}	8	10.9	13.0	13.3

The fact is that state air quality permitting requirements and rules do not always prevent exceedances or violations of the NAAQS or increments. Comments from the EPA directly spoke to this fact. As the Agency stated, "***mine emissions or emissions from other area sources***

[27] All increment data is presented in the Powder River Basin Coal Review report, Exhibit 13 at ES-7.

must be reduced before PRB operations are expanded to realize the upper range of future coal production." EPA Comments on Wright Area Coal DEIS, Exhibit 10 at 1 (emphasis added). The EPA further stated, "We recommend that the Final EIS add additional mitigation measures to reduce fugitive dust emissions. *Id*. In fact, the EPA pointed out that existing best available control measures for PM_{10}, stating:

> [W]e are recommending that the Final EIS analyze more effective dust control measures than the current Best Available Control Technology (BACT) and Best Available Control Measure practices and require additional mitigation to reduce fugitive dust from mining the lease tracts and the cumulative effects of mining in the surrounding area.

EPA Comments, Exhibit 10, Cover Letter at 1. This further exemplifies that there is no support for any claim that state air quality rules and permitting requirements will assure compliance with the 24-hour PM_{10} NAAQS and increments. Absent "additional mitigation measures" or a demonstration that mine emissions will be reduced, the USFS further has no basis for asserting that the FEIS adequately analyzes and assess impacts to the 24-hour PM_{10} NAAQS or the increments

Perhaps the failure to conduct an adequate analysis and assessment of PM_{10} impacts stems from the USFS's claim that it lacks authority to mitigate air quality impacts. This assertion is baseless as Grassland Plan explicitly requires the USFS to "Conduct all land management activities in such a manner as to comply with all applicable federal, state, and local air-quality standards and regulations" and to ensure that emissions "are within Class I [] ranges." The 24-hour PM_{10} NAAQS and increments are both clearly federal air quality standards and what's more, the increments represent the "Class I" ranges referred to in the Grassland Plan. Thus, the USFS not only has the authority, but the duty, to mitigate impacts in order to protect these standards, and therefore to ensure that impacts are adequately analyzed and assessed. The failure to do so violates NEPA.

F. Visibility

The Wright Area FEIS disclosed that visibility would be further impaired in a number of special areas, including Class I areas under the Clean Air Act and other sensitive Class II areas. Unfortunately, the USFS made no effort to assess the significance of these impacts in accordance with NEPA.

This oversight is significant, particularly in the context of Class I areas under the Clean Air Act. The Wright Area Coal FEIS discloses that nationally, the Clean Air Act has set a goal of "prevent[ing] any future, and remedy[ing] any existing, impairment of visibility in mandatory Federal Class I areas that result from manmade pollution." FEIS at 3-91. EPA regulations state that the term "visibility impairment" is defined as "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions." 40 C.F.R. § 51.301. The regulations state that "[a] single source that is responsible for a 1.0 deciview change or more should be considered to 'cause' visibility impairment" and that "determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews." 40 C.F.R. § 51 Appendix Y, Section III A. 1.[28]

The FEIS discloses that, even under a low production scenario, the North Porcupine LBA will increase the number of additional days in which visibility impacts will be greater than 1.0 deciview at 16 Class I areas, including Badlands National Park, Bridger Wilderness Area, Fitzpatrick Wilderness area, Fort Peck Indian Reservation, Gates of the Mountain Wilderness Area, Grand Teton National Park, North Absaroka Wilderness Area, North Cheyenne Indian Reservation, Red Rock Lakes, Scapegoat Wilderness Area, Teton Wilderness Area, Theodore Roosevelt National Park, UL Bend Wilderness Area, Washakie Wilderness Area, Wind Cave National Park, and Yellowstone National Park. *See* FEIS at 4-51. In the case of the Northern Cheyenne Indian Reservation and Badlands National Park, the number of additional days where visibility impacts will be greater than 1.0 deciview will be 59 and 44, respectively, under the low development scenario, the highest of any Class I areas.

Despite these disturbing disclosures, the USFS made no attempt to assess the significance of these projected visibility impacts, or to otherwise address such impacts through mitigation or other measures. It is as if the Agency simply disclosed the potential impacts, then did nothing more. This is utterly contrary to NEPA, which not only requires an analysis, but an assessment of the significance of impacts to ensure informed decisionmaking. *See* 40 C.F.R. §§ 1502.16, 1508.7, and 1508.8.

The failure of the USFS to assess visibility impacts arising from the North Porcupine LBA is especially disconcerting in light of the fact that the State of Wyoming has done nothing to address such impacts. Indeed, the EPA has officially declared that Wyoming, among many other states, has failed to submit rules to address visibility impacts from sources of air pollution within the State. *See* Finding of Failure to Submit State Implementation Plans Required by the 1999 Regional Haze Rule, 74 Fed. Reg. 2392-2395 (Jan. 15, 2009). Thus, the USFS has no reasonable basis upon which to rely on the State of Wyoming to address visibility impacts under NEPA.

V. The Supervisor Failed to Adequately Analyze Indirect and Cumulative Air Quality Impacts

The North Porcupine consent decision is also unlawful because the Supervisor failed to adequately analyze the indirect and cumulative air quality impacts associated with the North Porcupine LBA. As mentioned above, NEPA requires the USFS to analyze the indirect impacts of the North Porcupine consent decision, as well as the cumulative impact of this decision when combined with all other past, present, and reasonably foreseeable future actions. *See* 40 C.F.R. § 1508.25(c), 1508.7. Moreover, these analyses must be comparative: NEPA requires a robust comparison of the indirect and cumulative impacts of different alternatives. *Id.* §§ 1502.14, 1502.16.

[28] The BLM explains a deciview is a "general measure of view impairment (13 deciviews equals a view of approximately 60 miles) caused by pollution. A 10 percent change in extinction corresponds to 1.0 dv." FEIS at 7-3.

One of the principal indirect effects of the USFS's consent decision are the emissions resulting from coal combustion at the power plants receiving coal from the North Antelope Rochelle mine. In addition to the CO_2 emissions discussed above, coal-fired power plants emit significant quantities of other pollutants, such as mercury and other air toxics, sulfur dioxide ("SO_2"), NO_x, PM_{10}, and $PM_{2.5}$. It is undisputed that these pollutants, which are generated by coal combustion, negatively affect human health and the environment. *See generally* http://www.epa.gov/airquality/urbanair/ (last accessed Nov. 17, 2011) (links describing human health and environmental effects of SO_2, NO_x, PM pollution); 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*: *Proposed Rule*, 76 Fed. Reg. 24976 (May 3, 2011). Indeed, BLM itself admits that "pollutants generated by coal combustion that can cause health problems are particulates, sulfur and nitrogen oxides, trace elements[,] . . . organic compounds," mercury, and other metals such as lead and cadmium. FEIS at 4-151. Thus, in order to satisfy NEPA, the USFS and BLM were required to (a) thoroughly consider the environmental and health effects of power plant emissions resulting from this additional supply of North Antelope Rochelle coal, and (b) compare those estimated emissions under different alternatives. *See* 40 C.F.R. §§ 1502.14, 1502.16.

Here, however, the USFS and BLM completely failed to analyze the indirect air quality effects of the North Porcupine LBA. Neither the FEIS nor the ROD include *any* discussion of the effects of mercury and other air toxics, SO_2, NO_x, PM_{10}, and $PM_{2.5}$, and other emissions that will result from the combustion of this coal. This omission is a patent violation of NEPA. On this basis alone the North Porcupine ROD must be overturned.

Although the FEIS does include a few brief mentions of mercury emissions (*see generally* FEIS at 4-151 to 4-154), these conclusory paragraphs do not meet NEPA's requirements. *See e.g. Davis v. Mineta*, 302 F.3d 1104, 1122-23 (10th Cir. 2002) (rejecting indirect effects analysis that consisted of conclusory statements). Conspicuously missing from the FEIS is any attempt to quantify or otherwise analyze the environmental, health, and economic impacts resulting from such emissions. Nor does BLM make any attempt to compare the magnitude of these effects under different alternatives. Because the FEIS wholly fails to consider the indirect impacts of mercury and other air toxics, SO_2, NO_x, PM_{10}, and $PM_{2.5}$, and other emissions from coal-fired power plants under different alternatives, the ROD violates NEPA.

Nor can the Supervisor evade this NEPA requirement by claiming that these indirect air quality impacts are too diffuse to be analyzed. Information about the amount and destination of North Antelope Rochelle coal is readily available from the Department of Energy. As noted earlier, annual fuel receipt data from the EIA discloses every coal-fired power plant that burns coal from the North Antelope Rochelle coal mine. *See* Exhibit 6. Furthermore, by using the EPA's Clean Air Markets data website (*see* http://camddataandmaps.epa.gov/gdm/index.cfm) and Toxic Release Inventory website (*see* www.epa.gov/tri), the USFS could have estimated the emissions mercury and other air toxics, SO_2, NO_x, PM_{10}, and $PM_{2.5}$, and other emissions associated with the combustion of this coal, and therefore could have analyzed the anticipated emissions (and their effects) resulting from the North Porcupine LBA.

Indeed, a quick assessment of EPA's Clean Air Markets data indicates that coal from the North Antelope Rochelle mine is responsible for hundreds of thousands of tons of SO_2 and NOx. Just looking at the 13 coal-fired power plants that burn North Antelope Rochelle coal in Arizona, Colorado, Kansas, Nebraska, Oklahoma, and Wyoming, EPA's Clean Air Markets website discloses that these plants released 166,891 tons of SO_2 and 111,771.7 tons of NOx. *See* EPA, Clean Air Markets Data for 13 Coal-fired Power Plants (Aug. 27, 2011). This data is attached as Exhibit 14. Additionally, data regarding mercury and other toxic emissions for these facilities can be easily obtained from EPA's Toxic Release Inventory website.[29] For example, this data reports that the Martin Drake coal-fired power plant in Colorado released 92,138.22 pounds of toxic emissions into the air in 2010, including 7.8 pounds of lead, 10.9 pounds of mercury, and more. *See* EPA, Toxic Release Inventory Data for Martin Drake Coal-fired Power Plant (2011), *available at* http://oaspub.epa.gov/enviro/tris_control.tris_print?tris_id=80903MRTND700SC (last accessed Nov. 17, 2011). This data is also attached as Exhibit 15.

Even *if* the USFS lacked sufficient information to fully analyze the impacts of these emissions, the USFS cannot simply ignore them. *See e.g. Mid States Coalition for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549 (8th Cir. 2003) ("[W]hen the *nature* of the effect is reasonably foreseeable but its *extent* is not, we think that the agency may not simply ignore the effect."). Instead, where there is incomplete information about air quality impacts, the Agency must follow the specific procedures set forth in 40 C.F.R. § 1502.22. *See Mid States*, 345 F.3d at 549-50. Here, however, neither the BLM Nor the USFS made any attempt to satisfy the requirements of 40 C.F.R. § 1502.22. Given these deficiencies, the Supervisor could not lawfully issue his ROD.

BLM and USFS's failure to analyze the environmental, human health, and economic impacts of burning the North Porcupine LBA coal is compounded by the agencies' failure to consider the cumulative impacts of this consent decision. Under NEPA, "every EIS . . . requires cumulative analysis of possible environmental impacts." *New Mexico ex rel. Richardson v. BLM*, 565 F.3d 683, 719 n.45 (10th Cir. 2009) (citing 40 C.F.R. § 1508.25(c)). To satisfy this cumulative impacts requirement, at minimum the USFS should have analyzed (a) the combined effect of air emissions from the combustion of all the coal contained within the six Wright Area LBAs, and (b) the cumulative effect of these Wright Area emissions when combined with all other coal leases within the PRB. The USFS did neither. Simply put, the EIS and North Porcupine ROD completely fail to analyze the cumulative impacts of these coal combustion emissions when combined with other past, present, and reasonably foreseeable future actions. The North Porcupine ROD must be reversed.

VI. The Supervisor Failed to Comply with Grassland Plan Standards Related to Air Quality Protection

The USFS has a duty to ensure its actions are consistent with the Grassland Plan in

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[29] Toxic Release Inventory data can also easily be accessed through EPA's Environmental and Compliance History Online website at http://www.epa-echo.gov/echo/ (last accessed Nov. 17, 2011).

accordance with the National Forest Management Act ("NFMA"). *See* 16 U.S.C. § 1604(i) (stating, "[r]esource plans and permits, contracts, and other instruments for the use and occupancy of National Forest System lands shall be consistent with the land management plans"). Unfortunately, in this case the Supervisor failed to ensure that before consenting the North Porcupine LBA, that substantive air quality standards in the Grassland Plan would be met.

The Grassland Plan in particular contains three substantive air quality standards:

1. Conduct all land management activities in such a manner as to comply with all applicable federal, state, and local air-quality standards and regulations including: Federal Clean Air Act, as amended, 1990 (42 USC 7401-7671)[.]

2. Meet requirements of the Prevention of Significant Deterioration (PSD), State Implementation Plans (SIP), and applicable Smoke Management Plans.

3. Ensure emissions from projects on the Grassland and forest management activities are within Class I or Class II ranges. (See APPENDIX A regarding Class I Areas)[.]

Grassland Plan at 1-9, Physical Resources, Air Standards 1-3. The mandatory standards make clear that the USFS is obligated to comply with all "applicable federal, state, and local air-quality standards," to meet requirements of "the Prevention of Significant Deterioration," and to ensure emissions from projects are within "Class I or Class II ranges" as identified in Appendix A of the Grassland Plan.

The Supervisor's ROD in this case fell short of its legal obligations under NFMA in two critical ways. First, the USFS cannot fulfill its responsibility to ensure compliance with applicable air quality standards in accordance with the Grassland Plan without first analyzing the impacts of its actions to the air quality standards. In this case, the Supervisor blindly gave his consent to the North Porcupine LBA without even analyzing certain air quality impacts. Thus there is no rational basis for asserting the Supervisor has complied with the Grassland Plan.

Second, the Supervisor cannot approve the project knowing that its emissions, when combined with existing and reasonably foreseeable emissions, will result in significant deterioration of air quality and/or violations of NAAQS and other applicable air quality standards, including Class I increments. In this case the Wright Area Coal FEIS and modeling prepared by the BLM shows that development of the North Porcupine LBA will exceed a number of federal air quality standards that apply to this area, including Class I increments, contrary to its duties under NFMA and the Grassland Plan. The specific shortcomings are as follows:

A. Ozone

The USFS entirely failed to analyze or assess the impacts of developing the North Porcupine LBA to ambient ozone concentrations, notwithstanding the fact that monitors in the region have detected numerous exceedances of the ozone NAAQS, that the Thunder Basin National Grassland monitor is within ninety-two percent of the NAAQS, that modeling indicates ozone levels will exceed and/or violate the NAAQS, and that emissions of NO_x from operations at the North Antelope Rochelle coal mine are expected to be significant. In failing to analyze or assess the impacts of the North Porcupine LBA to ambient ozone concentrations, there is no support for any assertion that the USFS has complied with NFMA and the Grassland Plan's requirement that "federal [] air-quality standards" be complied with.

B. Nitrogen Dioxide

Similarly, the USFS did not analyze or assess the impacts of developing the North Porcupine LBA to the recently adopted 1-hour NO_2 NAAQS, at least in the Wyoming portion of the Powder River Basin, which is where the North Porcupine LBA is located. To the extent that the Wright Area Coal FEIS analyzed impacts to the 1-hour NO_2 NAAQS in Montana, the FEIS shows that exceedances of the NAAQS will occur. As the FEIS states, "the modeling results indicate that the 1-hour NO_2 concentrations at Montana near-field receptors for 2020 would exceed EPA's new 1-hour NAAQS[.]" FEIS at 4-48. The failure to analyze and assess the impacts of the North Porcupine LBA to the 1-hour NO_2 NAAQS in Wyoming, coupled with the fact that the FEIS clearly shows that the NAAQS will be exceeded in Montana, clearly indicates that the USFS has failed to ensure compliance with Grassland Plan standards, in violation of NFMA.

C. $PM_{2.5}$ NAAQS and Increments

Similar to the ozone and NO_2 NAAQS, the Wright Area Coal FEIS entirely fails to analyze and assess impacts to the 24-hour $PM_{2.5}$ increments for Class I areas. This fact, coupled with the fact that the FEIS and modeling prepared by the BLM indicates that exceedances of the 24-hour $PM_{2.5}$ Class I increments are occurring on the Northern Cheyenne Indian Reservation, in Badlands National Park, and in Wind Cave National Park, clearly indicates the USFS failed to comply with Grassland Plan standards that require the Agency to protect federal air quality standards, as well as ensure emissions are within "Class I" ranges.

Furthermore, as discussed earlier, the Wright Area Coal FEIS clearly shows that on a cumulative basis, the development of the North Porcupine LBA will exceed the 24-hour $PM_{2.5}$ NAAQS. Although the FEIS asserts have been no "monitored" exceedances of the $PM_{2.5}$ NAAQS, the FEIS also discloses that there are no $PM_{2.5}$ monitors in operation at the North Antelope Rochelle coal mine, or any of the other mines applying for coal leases under the Wright Area Coal FEIS. *See* FEIS at 3-52—3-54. Indeed, although the FEIS asserts that background 24-hour $PM_{2.5}$ concentrations were established based on "[d]ata collected at the Black Thunder Mine" (FEIS at 3-50), the FEIS show that there are only PM_{10} monitors in operation at the mine. *See* FEIS at 3-52. Regardless, the USFS has an affirmative duty to protect federal air quality standards under the Grassland Plan, which means that the Agency has a duty to prevent future exceedances of the 24-hour $PM_{2.5}$ NAAQS, which are clearly projected by the FEIS. The failure to ensure that development of the North Porcupine LBA will prevent future exceedances of the 24-hour $PM_{2.5}$ NAAQS renders the Supervisor's ROD in violation of NFMA.

D. PM_{10} NAAQS and Increments

As discussed earlier, the Wright Area Coal FEIS shows that on a cumulative basis, the development of the North Porcupine LBA will exceed the 24-hour PM_{10} NAAQS and increments for Class I areas, and that numerous exceedances of the 24-hour PM_{10} NAAQS have been recorded in recent years within the Powder River Basin.

The USFS does not seem to deny that exceedances of the 24-hour PM_{10} NAAQS have been recorded, or that the FEIS projects exceedances of the NAAQS and Class I increments, but rather seems to do nothing about it. This omission is wholly misplaced in light of the Grassland Plan's crystal clear and affirmative requirement that the USFS not only comply with federal air quality standards, but also ensure that emissions are within "Class I" ranges. The ranges referred to in Appendix A of the Grassland Plan include the 24-hour PM_{10} Class I increment. *See* Grassland Plan at Appendix A. Clearly, the USFS has failed to comply with its Grassland Plan in accordance with NFMA.

VII. The Supervisor Failed to Assure Compliance with Ferruginous Hawk Standards

The Supervisor's ROD violates NFMA by authorizing destruction of at least five active ferruginous hawk nests, in direct violation of the TBNG Grassland Plan. The ferruginous hawk is a USFS-designated sensitive species. The TBNG Grassland Plan explicitly prohibits the development of new facilities within 0.25 miles of an active ferruginous hawk nest. *See* Grassland Plan at 1-21, Biological Resources, Fish, Wildlife, and Rare Plants Standard 76. The Plan further prohibits construction activities within 0.5 miles of an active ferruginous hawk nest site from between March 1 to July 31. *See id.*, Standard 77. As is clear, the Grassland Plan outright prohibits certain activities during certain times within certain distances of active ferruginous hawk nests.

Despite this, the Supervisor's ROD consenting to the North Porcupine LBA allows construction activities and the development of new facilities that will destroy at least five active ferruginous hawk nests. The Supervisor's ROD itself nowhere mentions the need to protect ferruginous hawks within the lease area, or even the need to comply with the Grassland Plan. However, the FEIS indicates that there are at least five existing ferruginous hawk nests within the lease area. *See* FEIS at 3-203. It is unclear why the Supervisor did not address the impacts to these five ferruginous hawk nests, or explain how his ROD complied with the Grassland Plan's restrictions on development.

Instead, the USFS appears to impermissibly rely on the actions of other agencies to satisfy its own duties under the Grassland Plan and NFMA. In the RTC, the USFS asserts that, because "the State of Wyoming and the U.S. Fish and Wildlife Service were both consulted," it is permissible to violate the Grassland Plan's ferruginous hawk protection standard. *See* RTC at 55. The USFS may not, however, waive or otherwise modify its Grassland Plan standards simply because it may have consulted with the State of Wyoming and U.S. Fish and Wildlife Service. Such an approach runs squarely afoul of NFMA.

The USFS seems to assert that where a "wildlife agency permit has been issued," Grassland Plan Standards may be waived. This approach is not only an egregious misinterpretation of the Plan, it is not supported by the facts of this case. Indeed, neither the State of Wyoming nor the U.S. Fish and Wildlife Service issue "wildlife agency permits" authorizing impacts to ferruginous hawks or other species on the TBNG that will directly result from coal leasing. Furthermore, to the extent "wildlife agency permits" may authorize the USFS in some instances to permit activities otherwise prohibited by the Grassland Plan, this provision does not allow the USFS to unilaterally waive Standards, such as those related to the protection of the ferruginous hawk.

As stated in the Grassland Plan, the USFS can only deviate from Standards on a site-specific basis if it first "analyze[s] and document[s] [such a deviation] in management plan amendments." Grassland Plan at G-56. Federal courts have recognized this requirement under NFMA that the USFS must amend a Plan before the USFS may issue a decision authorizing activities prohibited by that Plan. See *Ctr. for Sierra Nevada Conservation v. U.S. Forest Serv.*, CIV. S-09-2523 LKK, 2011 WL 2119101 at *23-24 (E.D. Cal. May 26, 2011) (holding that a USFS "Travel Management Decision" that was inconsistent with two Forest Plans was prohibited because the USFS did not first amend those plans to allow the activities authorized by the decision). Furthermore, such amendments to the Grassland Plan may themselves require the preparation of an EIS. *See id*. at footnote 23. In issuing its consent to the North Porcupine LBA, the USFS has not proposed to amend the Grassland Plan. Thus, the USFS may not simply ignore Standards enumerated in the Plan that protect the ferruginous hawk and its nesting sites.

The Supervisor's ROD flagrantly violates NFMA and the Grassland Plan standards prohibiting new facilities and construction activities within certain distances of ferruginous hawk nests. The destruction of five active ferruginous hawk nests can hardly be representative of compliance with the Grassland Plan, and the Supervisor has provided no valid reason for consenting to the North Porcupine LBA without first ensuring compliance with ferruginous hawk protection requirements, or at the very least amending the Plan to authorize activities that are currently prohibited by those protection requirements.

VIII. The USFS Failed to Adequately Analyze and Assess Grazing Impacts

The USFS has an independent duty under NEPA to properly analyze any environmental and socio-economic impacts related to its proposed actions. While BLM's NEPA analysis is focused on developing the mineral estate underlying these leases, the USFS's NEPA analysis should be focused on the surface estate and particularly impacts to existing land uses of the TBNG. In this case, the main existing use of the proposed North Porcupine LBA is rangeland for livestock and wildlife. As the ROD states, livestock grazing is a "significant management activit[y]" in the North Porcupine LBA area. ROD at 7. Unfortunately, the USFS failed to adequately analyze the impacts of the North Porcupine LBA to livestock grazing.

Indeed, although the USFS largely defers to the BLM's NEPA analysis, that analysis gave only a cursory overview of impacts to grazing lessees that will result from the leasing and subsequent mining of the North Porcupine LBA. In fact, BLM's socio-economic impacts analysis in its FEIS is focused solely on projected tax revenue and employment that the mining activity will bring. *See* FEIS at 3-300. BLM's analysis ignores the substantial socio-economic impacts that will result to area ranchers from a direct loss of grazing leases. This exactly the kind of impacts analysis the USFS is required to do, but that unfortunately the Agency fell short of completing.

The ROD and RTC merely underscore the USFS's failure to analyze the socioeconomic impacts resulting from the loss of grazing land. First, rather than acknowledge its independent duty under NEPA to analyze such impacts, the USFS simply recites its status as a cooperating agency and then cites to BLM's EIS. *See* RTC at 51-52. As discussed earlier in this appeal, however, the agency's status as a cooperating agency does not excuse it from ensuring compliance with NEPA.

Second, even if the USFS could rely on the BLM's EIS to satisfy its NEPA obligations, BLM's own analysis was inadequate. The USFS claims that "impacts to grazing" were addressed in five pages of the FEIS. *See* RTC at 52. In fact, the socioeconomic impacts from the loss of grazing land were not analyzed at all. The FEIS simply lists the number of acres and allotments that would be lost, admits that several ranchers would lose their allotments, and cursorily observed that such losses might "negatively impact the ranchers that were allocated those AUMs for their livestock operations," and that "the loss of TBNG grazing use due to the leasing and subsequent mining of the WAC LBA tracts could cause serious impacts to [ranchers'] livestock operations and family ranches." FEIS at 3-263 to 3-264. The ROD simply echoes these statements. *See* ROD at 25-26. These disclosures, however, do not remedy the fact that the USFS has not completed any actual analysis of the social and economic effects of this loss of grazing land. NEPA requires that in analyzing and assessing direct, indirect, and cumulative effects an EIS must consider both social and economic impacts. *See* 40 C.F.R. §§ 1502.16, 1508.8. The FEIS and ROD are inadequate because they are merely post-hoc rationalizations and in fact confirm that the USFS failed to conduct an analysis of socio-economic impacts to livestock grazing through the NEPA process.

BLM's analysis of grazing-related impacts is also inadequate because the EIS fails to compare those impacts under different alternatives. Under NEPA, the discussion of a project's environmental, social, and economic effects must identify how those impacts ***vary under different alternatives***. *See* 40 C.F.R. §§ 1502.14, 1502.15. Here, BLM made no attempt to do so with respect to grazing-related impacts and the USFS's ROD and RTC further fail to analyze how the impacts to livestock grazing vary by alternative. By failing to provide a robust comparison of the anticipated effects under different alternatives, the FEIS violated NEPA, and the Supervisor's ROD must be reversed.

IX. The USFS Failed to Adequately Analyze and Assess Compliance with Contemporaneous Reclamation Requirements and Associated Environmental Impacts

The Supervisor also illegally relied upon BLM's EIS because it fails to analyze the reclamation status at the North Antelope Rochelle coal mine as well as the ongoing direct, indirect and cumulative impacts that continue to occur as a result of a lack of contemporaneous reclamation at not only the mine, but coal mines throughout the PRB. One of the most important legal requirements for coal mining in the United States is that reclamation of mined land must be "as contemporaneous as possible." 30 U.S.C. § 1202(e). Contemporaneous reclamation promotes environmental protection of land and water resources by minimizing the length of time lands are disturbed, maintaining stable non-eroding mine sites, reducing fugitive dust from un-vegetated areas, and helping to achieve productive end land uses.

Absent ensured contemporaneous reclamation, land may not be able to be restored "to a condition equal to or greater than the 'highest previous use'" as required by Federal and Wyoming laws. *See* Wyo. Land Quality Regulations Ch. 3 § 2(a)(i). Contemporaneous reclamation is an integral part of SMCRA which Congress passed to "ensure that coal mining operations are conducted in an environmentally responsible manner and that the land is adequately reclaimed during and following the mining process." *See* Office of Surface Mining Reclamation and Enforcement, *Regulating Coal Mines*.[30] As Congress identified, "[b]y imposing workable reclamation standards nationwide through the enactment of [SMCRA], the unnecessary degradation of land and water resources will be avoided as the country makes good use of its abundant coal supply." H.R. REP. NO. 95-218, at 57 (1977). Contemporaneous reclamation is especially important in the context of public grasslands because if it does not occur, excessive amounts of land will be tied up in coal mining operations and unavailable for other uses, including livestock grazing, wildlife, and recreation. Achieving contemporaneous reclamation and return of previously mined lands to USFS control is thus necessary to ensure that the "multiple use" mandate of the Forest Service is being met.

The USFS acknowledges that SMCRA is one of the legal authorities under which the agency and BLM evaluated the LBA tract. *See* ROD at 7. However, further review of the FEIS demonstrates that the USFS did not evaluate SMCRA compliance of the mine or proposed lease either independently or even in conjunction with BLM's FEIS. In the FEIS, BLM failed to meet the "hard look" requirements to consider environmental impacts related to bond release status. While BLM briefly mentions the amount of acreage of PRB mines that have attained Phase I, II, and III bond release in 2009 (*see* FEIS at 3-189), merely listing the numbers does not accurately analyze the cumulative reclamation status of the North Antelope Rochelle coal mine or other Wyoming coal mines.[31] In its FEIS, BLM failed to disclose the bond release status for each of the Wright Area mines, including the North Antelope Rochelle coal mine. Additionally, and importantly, BLM does not disclose any environmental impacts related to the lack of bond release and subsequent lack of contemporaneous reclamation.

BLM has acknowledged that it has not done this analysis, instead claiming that "a percentage assessment of lands that have been released from final bonding requirements is not an accurate assessment of 'contemporaneous' reclamation." FEIS, Appendix I, Response to Comments at 11; Analysis of Public Comments at 11. BLM's claim ignores the requirements of its sister agency, the Office of Surface Mining Reclamation and Enforcement ("OSMRE"), and REG-8 and other directives dictating that bond release is a measure of reclamation status and

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[30] *See* http://www.osmre.gov/rcm/rcm.shtm (last accessed Nov. 17, 2011).

[31] BLM only includes the numbers from evaluation year 2009. The cumulative numbers must be considered.

success. OSMRE has repeatedly recognized the lack of progress that Wyoming coal mines are making on bond release.[32] OSMRE has determined that the Wyoming program "[is] not effective in facilitating and encouraging bond release" as defined by the agency. OSMRE, Wyoming Annual Oversight Report (2004) at 8, *available at* http://www.osmre.gov/Reports/EvalInfo/2004/wyoming04.pdf (last accessed Nov. 17, 2011). This report is attached as Exhibit 16. Partially as a result of the lack of bond release, particularly Phase III bonds, agency reports also express concern about the lack of contemporaneous reclamation. In its 2005 Wyoming Annual Oversight Report, for example, OSM found that, notwithstanding "the intent of SMCRA to assure that" mined land is reclaimed "as contemporaneously as possible," "the gap between the acres disturbed versus reclaimed is widening." 2005 Wyoming Annual Oversight Report at 7; *see also* 2004 Wyoming Annual Oversight Report at 11; 2006 Wyoming Annual Oversight Report at 9. In 2008, OSM stated that the agency "has continued to review and evaluate the contemporaneous reclamation provisions of the Wyoming program for more than a decade. Each review has raised some general concern that contemporaneous reclamation and movement of reclaimed acres towards eventual bond release is not fully consistent with the intent of the State's reclamation program." 2008 Wyoming Annual Oversight Report at 17.

By 2009, "151,186 acres have been disturbed and of that 6,197 acres (5.3%) have received Phase III bond release in Wyoming." 2009 Wyoming Annual Oversight Report at 8-9. This ratio dropped even further in the 2010 evaluation report, with only 6,517 acres receiving Phase III bond release out of 162, 249 acres disturbed, or 4% acres total. 2010 Wyoming Annual Oversight Report at 7. Only 341 acres were released from Phase III bonds in Fiscal Year 2009 whereas 5,497 acres were disturbed. 2009 Report at 27. This is a ratio of 0.06. In 2010, only 320 acres received Phase III release, and 5,566 acres were disturbed. 2010 Report at 8. This is also a ratio of nearly 0.06.

While Wyoming's DEQ may have delegated authority to issue mining permits for the North Antelope Rochelle mine, the USFS has a duty under NEPA to analyze environmental, public health and socio-economic impacts that may result from leasing the North Porcupine tract for additional coal development – including ongoing and future impacts from continued (non)contemporaneous reclamation at the mine(s) in the PRB. As BLM's FEIS rightly concludes, even though the Federal agencies "do[] not authorize mining," they still must, pursuant to NEPA, consider "the impacts of mining the coal" because these impacts "are a logical consequence of issuing a maintenance lease to an existing mine." FEIS at 1-4.

The USFS, as the Federal surface owner for much of this LBA, is under a statutory duty pursuant to NEPA to analyze the direct, indirect and cumulative impacts of the impacts of consenting to BLM's proposed lease including impacts that will result from a lack of reclamation at both the North Antelope Rochelle mine as well as other coal mines in the PRB. This duty must be realized prior to authorizing additional leasing. The NEPA process must "analyze not

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[32] *See e.g.*, Wyoming Annual Oversight Reports for 2002, 2003, 2004, 2005, 2006, 2008, 2009, and 2010. These reports are all available at http://www.osmre.gov/Reports/EvalInfo/EvalInfo.shtm (last accessed Nov. 17, 2011). The Wyoming reports for both 2003 and 2004 note (at page 8) not only the lack of bond releases, but also that the industry is trying to change performance requirements for release, rather than actually moving forward with bond release applications.

only the direct impacts of a proposed action, but also the indirect and cumulative impacts of 'past, present, and reasonable foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions.'" *Custer County Action Ass'n v. Garvey*, 256 F.3d 1024, 1035 (10th Cir. 2001). One of the twin aims of NEPA is that "it places upon an agency the obligation to consider every significant aspect of the environmental impact of a proposed action." *Balt. Gas & Elec. Co. v. NRDC*, 462 U.S. 87, 97 (1983) (cite omitted). Additionally, as discussed above, the USFS evaluates a proposal to lease coal under several legal authorities, including NEPA and SMCRA. In order to properly evaluate the proposal under those authorities, the USFS should analyze documents and other information from cooperating agencies on the EIS (OSM and DEQ) that show that the North Antelope Rochelle mine and coal mines across the Powder River Basin are failing to meet contemporaneous reclamation criteria, as discussed above. *See* 40 C.F.R. §1508.5 (cooperating agencies); *accord* 46 Fed. Reg. 18062 (1981) (40 Most Asked Questions Concerning CEQ's NEPA Regulations) (requiring that NEPA documents analyze and include "joint research and studies, planning activities…" from cooperating agencies). "[A] reviewing court 'may properly be skeptical as to whether an EIS's conclusions have a substantial basis in fact if the responsible agency has apparently ignored the conflicting views of other agencies having pertinent expertise.'" *Davis v. Mineta*, 302 F.3d 1104 (10th Cir. 2002) (cite omitted).

If a logical result of leasing the coal is that more land will be disturbed and not reclaimed in a timely manner, as the information from OSM and DEQ affirmatively demonstrates, then the USFS must analyze those impacts through a NEPA document analyzing the impacts of authorizing the additional lease of national public coal reserves. *See* 40 C.F.R. § 1502.16 (requiring analysis of direct and indirect effects including "[t]he environmental effects of alternatives including the proposed action."). The USFS's failure to analyze this issue resulted in the agency's concurrent failure to analyze any environmental, socio-economic, or public health impacts that result because of untimely reclamation.

In addition to failing to analyze reclamation status and resulting impacts—now or foreseeable in the future—the USFS has not complied with its duties under NEPA to consider a reasonable range of alternatives and mitigation options related to reclamation.

Through comments on BLM's draft and final EISs, Appellant Powder River Basin Resource Council asked BLM to consider several reasonable alternatives related to reclamation, including delaying the lease of proposed tracts until reclamation at current tracts is complete. *See e.g.* Powder River Basin Resource Council Comments on FEIS at 4 and Comments on DEIS at 7-8.

While BLM considered, but eliminated from detailed analysis, a delay alternative, that alternative was framed in the context of "tak[ing] advantage of higher coal prices and/or allow[ing] recovery of the potential coal bed natural gas resources in the tract prior to mining." FEIS at 2-8, 2-67-68. BLM, or the USFS, failed to consider the environmental benefits of a delay alternative associated with delaying a lease of the tract until the mines achieve contemporaneous reclamation as indicated by bond release status. Delaying leasing would not unduly harm the applicant because the North Antelope Rochelle mine has roughly ten years of recoverable coal reserves at current mining rates. *See* ROD at 9.

Powder River Basin Resource Council also asked BLM to consider lease stipulations related to reclamation, suggesting that "BLM could propose a lease stipulation that would prevent mining associated with the lease tract until the mine achieves a certain level of final bond release of previously mined lands (30%, 50%, or 75% for example)." Powder River Basin Resource Council Comments on FEIS at 4.

Finally, Powder River Basin Resource Council suggested that BLM analyze alternatives such as decreasing the amount of coal leased or "leas[ing] only one tract of coal per mine, which would limit expansion of mining operations to one direction and allow a greater emphasis on reclamation." Powder River Basin Resource Council Comments on FEIS at 4. The Council explained that "if BLM slows its leasing pace, this may help to promote contemporaneous reclamation of previously mined lands" because more leased acreage would only be available after reclamation and bond release of previously leased areas. *Id*.

By failing to consider these reasonable alternatives suggested by Powder River Basin Resource Council, BLM's FEIS does not meet the requirements of NEPA. *See e.g. Friends of Southeast's Future v. Morrison*, 153 F.3d 1059, 1065 (9th Cir. 1998) (holding that "The existence of reasonable but unexamined alternatives renders an EIS inadequate"). This once again demonstrates that the FEIS is a legally deficient document that cannot be relied upon by the USFS. Additionally, as discussed above, the USFS has an independent duty to analyze impacts and consider alternatives related to its consent of the North Porcupine LBA. The USFS has failed to meet these requirements in the case of considering impacts and alternatives related to reclamation.

In addition to failing to consider alternatives, the USFS also failed to consider mitigation measures related to reclamation. Federal agencies are required to develop, discuss in detail, and identify the likely environmental consequences of proposed mitigation measures. *See* 40 C.F.R. §§ 1508.25(b), 1502.14(f), 1502.16(h), and 1505.2(c).

X. The Supervisor Failed to Consider Mitigation Measures Related to Groundwater Impacts or to Ensure Compliance with SMCRA's Mandates to Minimize Impacts to the Hydrologic Balance

The Powder River Basin is an arid environment, with limited rainfall and surface water resources. Therefore, most residents, including Appellants' members, rely upon groundwater resources for home and ranch use, including water from the coal seams of the PRB. In evaluating additional leasing, the USFS fails to analyze how, if at all, hydrologic reclamation will occur and, in particular, alternatives and mitigation measures which would ensure reestablishment of the hydrologic balance.

The FEIS discloses significant site-specific and cumulative impacts to groundwater resources. Through surface coal mining, "[t]he overburden and coal aquifers within the leased tracts would be completely dewatered and removed, and the area of drawdown caused by overburden and coal removal would be extended…" FEIS at 3-111. BLM states that "[t]he rate and extent of the actual drawdown in the coal is currently much greater than the life-of-mine drawdown predictions" and that "[r]oughly 30 years of surface mining and the more recent CBNG [coal-bed natural gas] development have resulted in complete dewatering of the coal aquifer in localized areas…" FEIS at ES-40, 3-118. Additionally, the Agency discloses that "resaturation of coal mine pit backfill to form backfill aquifers may take approximately 100 years after cessation of mining." FEIS at ES-67. The information in the FEIS indicates that there are substantial and irreparable impacts to the aquifers that will result from continued (or in this case expanded) mining of the North Porcupine LBA and cumulatively with the other Wright Area coal leases. However, in reaching these conclusions, the BLM's FEIS fails to analyze measures for *hydrologic reclamation* (i.e. the extent to which these adverse effects "<u>can be avoided</u>" or mitigated). *Robertson*, 490 U.S. at 351-52 (emphasis supplied); *see e.g.* 40 C.F.R. § 1502.14(f) (an EIS must "[i]nclude appropriate mitigation measures not already included in the proposed action or alternatives").

The USFS must conduct a thorough analysis of impacts and mitigation measures to demonstrate their enforceability and effectiveness. *See e.g.* 40 C.F.R. § 1502.14(f) (an EIS must "[i]nclude appropriate mitigation measures not already included in the proposed action or alternatives"). The USFS has a duty to consider mitigation clearly within its authority (such as lease stipulations) and mitigation and alternatives not within its jurisdiction.

Moreover, BLM's analysis of groundwater impacts and water restoration in the FEIS fails to properly analyze compliance with SMCRA's requirements. The BLM's cooperating agency on the FEIS, OSM, has determined that achievement of surface water quality and quantity restoration and ground water recharge capacity and quantity and quality restoration is to be measured by Phase III bond release. *See* OSM Directive REG-8, *Oversight of State Regulatory Programs* (December 21, 2006) at 1-12, *available at* www.osmre.gov/guidance/directives/archive/directive921.pdf (last accessed Nov. 17, 2011). By this measure, hydrologic reclamation is *not* being achieved in the Powder River Basin or at the North Antelope Rochelle coal mine. *See* 2009 Wyoming Annual Oversight Report at 8-9 (AR 093587) ("[t]o date 151,186 acres have been disturbed and of that 6,197 acres (5.3%) have received Phase III bond release in Wyoming.")

BLM also has an obligation to analyze cumulative impacts and consider reasonable measures to mitigate those impacts. As BLM's FEIS acknowledges, "groundwater impacts from CBNG [coalbed natural gas] development and surface coal mining are additive in nature and…the addition of CBNG development has greatly extended the area experiencing a loss of hydraulic head to the west of the mining area." FEIS at ES-65. The FEIS further states that "[d]ewatering activities associated with CBNG development have overlapped with and expanded the area of groundwater drawdown in the coal aquifer in the PRB over what would occur due to coal mining development alone, and this would be expected to continue" with the addition of the new lease tracts. FEIS at 4-62. That said it is incumbent upon BLM to determine, analyze and mitigate the cumulative impacts of dewatering for mining (in conjunction with overlapping CBNG development).

BLM fails to conduct *any* analysis of mitigation measures related to groundwater impacts in this FEIS and thus violates NEPA's "hard look" requirements. Consequently, the

Supervisor's ROD is similarly in violation of NEPA and must be reversed.

REQUEST FOR RELIEF

For the aforementioned reasons, the Appellants hereby request the following relief:

1. That the ROD consenting to the issuance of the North Porcupine LBA be set aside on the grounds that it violates NEPA, SMCRA, NFMA, the Grassland Plan, the Administrative Procedure Act, and other federal laws and regulations.

2. That if the USFS decides to continue offering its consent to the North Porcupine LBA, the Supervisor be instructed to complete an independent analysis of the impacts, including consideration of a range of reasonable alternatives, of consenting to the LBA in accordance with NEPA.

3. That if the USFS decides to continue offering its consent to the North Porcupine LBA, that the Secretary of Agriculture first determine whether the lands in question are suitable for surface mining in accordance with SMCRA and ensure compliance with SMCRA's substantive requirements.

4. That if the USFS decides to continue offering its consent to the North Porcupine LBA, that the Supervisor be instructed to fully analyze and assess the indirect and cumulative global climate change impacts associated with the LBA, and fully consider in detail a range of alternatives to address the global climate change impacts associated with the LBA.

5. That if the USFS decides to continue offering its consent to the North Porcupine LBA, that the Supervisor be instructed to fully analyze and assess the direct, indirect, and cumulative air quality impacts associated with development of the LBA and protect air quality standards in accordance with the Grassland Plan.

6. That if the USFS decides to continue offering its consent to the North Porcupine LBA, that the Supervisor be instructed to fully comply with all other Grassland Plan standards and guidelines, including standards related to the protection of ferruginous hawk nest sites.

7. That if the USFS decides to continue offering its consent to the North Porcupine LBA, that the Supervisor be instructed to complete a full analysis of the socio-economic impacts to livestock grazing.

8. That if the USFS decides to continue offering its consent to the North Porcupine LBA, that the Supervisor be instructed to Ensure Compliance with Contemporaneous Reclamation Requirements and Groundwater Protection Requirements Under SMCRA.

Respectfully submitted November 18, 2011,

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TABLE OF EXHIBITS

Exhibit 1: *Statement of Tom Tidwell, USDA Forest Service Chief, Before the Senate Committee on Appropriates Subcommittee on Interior Environment and Related Agencies* (March 17, 2010) at 4, *available at* http://appropriations.senate.gov/ht-interior.cfm?method=hearings.download&id=2bcfbdfe-80cd-4dbb-b0e4-1d6a2d62288f (last accessed Nov. 17, 2011).

Exhibit 2: Tomich, J., "Peabody planning Asian coal shipments through Washington," *St. Louis Post-Dispatch* (March 2, 2011), *available at* http://trib.com/news/state-and-regional/article_8fd85e5a-a2d7-5e54-a2be-a369c4da84d6.html (last accessed Nov. 17, 2011).

Exhibit 3: Excerpts of U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, 1990-2008, EPA 430-R-10-006 (April 15, 2010), at 3-1 *available at* http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Report.pdf (last accessed Aug. 25, 2011).

Exhibit 4: U.S. EPA (2011), "Inventory of U.S. Greenhouse Gas Emissions and Sinks: Fast Facts," *available at* http://epa.gov/climatechange/emissions/downloads11/GHG-Fast-Facts-2009.pdf (last visited Nov. 17, 2011).

Exhibit 5: BLM, *Record of Decision Environmental Impact Statement for the North Porcupine Field Coal Lease Application, WYW173408* (October 2011), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/hpdo/Wright-Coal/n-porcupine.Par.91450.File.dat/ROD.pdf (last accessed Nov. 17, 2011)

Exhibit 6: EIA Form 923 Data for North Antelope Rochelle coal mine (2010), *available at* http://www.eia.gov/cneaf/electricity/page/eia423.html (last accessed Nov. 17, 2011).

Exhibit 7: Hong, B.D. and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," EIA, *Quarterly Coal Report, January—April 1994*, DOE/EIA-0121 (94/Q1) (Aug. 1994), *available at* http://205.254.135.24/cneaf/coal/quarterly/co2_article/co2.html (last accessed Nov. 17, 2011).

Exhibit 8: USFS, *Climate Change Considerations in Project Level NEPA Analysis* (Jan. 13, 2009) at 6-7, *available at* http://www.fs.fed.us/emc/nepa/climate_change/includes/cc_nepa_guidance.pdf (last accessed Nov. 17, 2011).

Exhibit 9: U.S. EPA, *Daily Ozone AQI* Levels, 2005-2010, Campbell County, Wyoming.

Exhibit 10: U.S. EPA, Comments on Wright Area Coal DEIS (Sept. 10, 2009), *available at* http://yosemite.epa.gov/oeca/webeis.nsf/(PDFView)/20090209/$file/20090209.PDF?OpenElement (last accessed Nov. 17, 2011).

Exhibit 11: Tonnesen, G., Z. Wang, M. Omary, C. Chien, Z. Adelman, and R. Morris, et al., *Review of Ozone Performance in WRAP Modeling and Relevance to Future Regional Ozone Planning*, presentation given at WRAP Technical Analysis Meeting (July 30, 2008) at unnumbered slide 30, *available at* http://wrapair.org/forums/toc/meetings/080729m/RMC_Denver_OzoneMPE_Final2.pdf (last accessed Nov. 17, 2011).

Exhibit 12: U.S. EPA, Comments on Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Sublette County, Wyoming (February 14, 2008) at 3, *available at* http://www.wyomingoutdoorcouncil.org/html/what_we_do/air_quality/pdfs/EPA%20EU3%20Letter%20on%20Revised%20Draft%20SEIS.pdf (last accessed Nov. 17, 2011).

Exhibit 13: COM, *Update of Task 3A Report for the Powder River Basin Coal Review Cumulative Air Quality Effects for 2020*, Prepared for Bureau of Land Management, High Plains District Office, Wyoming State Office, and Miles City Field Office (Dec. 2009) at ES-6, *available at* http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/prbdocs/coalreview/task_3a-2020.html (last accessed Nov. 17, 2011).

Exhibit 14: EPA, Clean Air Markets Data for 13 Coal-fired Power Plants (Aug. 27, 2011).

Exhibit 15: EPA, Toxic Release Inventory Data for Martin Drake Coal-fired Power Plant (2011), *available at* http://oaspub.epa.gov/enviro/tris_control.tris_print?tris_id=80903MRTND700SC (last accessed Nov. 17, 2011).

Exhibit 16: OSMRE, Wyoming Annual Oversight Report (2004) at 8, *available at* http://www.osmre.gov/Reports/EvalInfo/2004/wyoming04.pdf (last accessed Nov. 17, 2011).

Exhibit 1

Statement of Tom Tidwell, USDA Forest Service Chief, Before the Senate Committee on Appropriates Subcommittee on Interior Environment and Related Agencies (March 17, 2010)

Statement of
Tom Tidwell, USDA Forest Service Chief

Before the
Senate Committee on Appropriations
Subcommittee on Interior, Environment, and Related Agencies

Concerning

The President's Budget Request for the USDA Forest Service in Fiscal Year 2011

March 17, 2010

Madam Chairman and members of the subcommittee, it is a privilege to be here today to discuss the President's Budget request for the Forest Service in fiscal year (FY) 2011. I appreciate the support this subcommittee has shown the Forest Service in the past, and I look forward to collaborating in the future to provide more of the things the American people want and need from our Nation's forests and grasslands. I am confident that this budget will enable the Forest Service to do just that.

Our Nation's forests and grasslands, both public and private, are social, economic, and environmental assets. They provide many ecosystem services on which society relies, including clean water, scenic beauty, outdoor recreation, fish and wildlife habitat, natural resource jobs, forest products, renewable energy, carbon sequestration, and more. In pursuit of these and other services, the Forest Service manages 193 million acres on 155 national forests and 20 grasslands. In addition, to help improve stewardship of lands outside the National Forest System, the agency partners with and provides technical assistance to a range of other Federal agencies as well as State, local, and Tribal governments, private landowners, and nonprofit organizations. The agency also engages in cutting-edge research on climate change, wildfires, forest pests and diseases, ecological restoration, and a range of other conservation issues.

The Budget reflects the President's priorities and Secretary of Agriculture Tom Vilsack's vision for restoring and enhancing the resilience and productivity of America's forests. In accordance with our mission of sustaining the health, diversity, and productivity of the nation's forests and grasslands, the Forest Service is taking an all-lands approach, working across boundaries and ownerships to address the critical issues facing our Nation's forest and grassland ecosystems on a landscape scale. Further, the budget proposes to integrate Forest Service programs in a new way that will better position the agency to tackle long-standing and urgent forest health, wildlife, forest restoration, and community vitality needs.

The President's Budget request for the Forest Service for FY11 totals $5.38 billion in discretionary appropriations, a $61 million increase over the FY10 enacted level. The Budget reflects a new and significant shift in the way the agency will address forest management on National Forest System (NFS) lands. The President's Budget focuses Forest Service resources to support more watershed and ecosystem improvement efforts based upon a variety of management actions, including mechanical removal of timber, road decommissioning, and wildlife habitat improvement. The Budget adopts an ecosystem-based approach to forest management that focuses on enhancing forest and watershed resiliency, preventing the loss of large carbon sinks, and maintaining jobs. To address the need to protect forest resources and wildlife habitat in an era of global climate change, the Budget establishes a pilot program for long-term, landscape scale restoration activities that emphasize resiliency, health, and sustainable economic development.

Ecological Restoration

In FY 2011, the Forest Service will work to meet the challenge of restoring healthy, resilient ecosystems capable of delivering the ecosystem services that Americans depend upon, especially clean and abundant water. The Administration proposes restructuring the Forest Service budget as a key step that will allow us to focus more on high priority restoration work. The new budget line item, Integrated Resource Restoration, will combine the Forest Products, Vegetation and Watershed Management, and Wildlife and Fisheries Management budget line items. The FY 2011 budget proposes $694 million for Integrated Resource Restoration work under this line item.

We believe this new line item better reflects much of the current work we do and, even more importantly, better forecasts the future direction we need to take to achieve ecological restoration work. The agency will integrate traditional timber activities predominately within the context of larger restoration objectives, focusing on priority watersheds in most need of stewardship and restoration work, pursuing forest products when they support watershed, wildlife, and restoration goals. We will also greatly expand the use of the stewardship contracting authority to meet restoration objectives and build in longer-term contracting certainty for communities and the private sector to invest in the kind of forest restoration infrastructure we will need to achieve these objectives.

The new budget line item consists of three activities: $604 million for Restoration and Management of Ecosystems, $40 million for the Collaborative Forest Landscape Restoration Act (CFLRA), and $50 million for Priority Watersheds and Job Stabilization. Projects under the second two will be selected through a national competitive process and are discussed below. The $604 million for Restoration and Management of Ecosystems will be allocated in part based on the number of smaller watersheds (6th level hydrological unit codes, which average 10,000 acres) in critical need of restoration, while a substantial portion of the funds will be used to fund restoration activities across the National Forest System. This will allow National Forests to focus local projects on improving watershed condition while continuing to carryout critical, ongoing ecological restoration work. While we have not worked out the specifics for allocating these funds, I am convinced that this multi-pronged approach will improve our ability to achieve restoration and watershed improvement at various scales – from landscape level work under the nationally selected projects under CFLRA and the Priority Watersheds initiatives to work within individual NFS watersheds in need of critical restoration – while allowing the Forest Service to place greater focus on improving watersheds without forgoing critical ongoing restoration efforts. We look forward to working with the subcommittee as we explore the best way to allocate these funds.

Collaborative Forest Landscape Restoration Fund

The FY11 President's Budget requests $40 million to fund ecosystem restoration under the Forest Landscape Restoration Act of 2009, the maximum amount authorized under the Act. Restoration treatments will focus on reducing the risk of catastrophic wildfire, improving watershed conditions, and building resilience to climate change on large landscapes greater than 50,000 acres. Through the Collaborative Forest Landscape Restoration Program, the Forest Service will use federal funding to leverage local resources, engaging partners in collaborative restoration efforts on a landscape scale. Potential projects will be developed and proposed through multi-stakeholder collaborative planning, and will be selected by the Secretary of Agriculture, as advised by a Federal Advisory Committee. Proposals must have a substantially complete restoration strategy, be primarily composed of National Forest System land, and be on lands accessible by wood-processing infrastructure. The $50 million priority watersheds initiative and the CFLRF will provide perfect complement to each other within the Integrated Resource Restoration line item, enabling the agency to target management to the diversity of landscape, forest, and community needs. In FY11, the Forest Service would fund 10 projects at $4 million each through CFLRF. No more than two proposals will be selected for funding in any one Region of the NFS.

Priority Watersheds and Job Stabilization

Perhaps the most important service that Americans get from wildland ecosystems has to do with a basic human need: water. Nearly 53 percent of the Nation's freshwater supply originates on public and private forest lands, and more than 200 million people rely for their daily drinking water on forests and grasslands. Watersheds in good health provide good water quality, and watersheds that deliver plentiful supplies of pure, clean water also deliver a full range of other services that people need—soil protection, carbon storage, wildlife habitat, opportunities for outdoor recreation, and more.

In FY 2011, the Forest Service proposes to invest $50 million under the new Integrated Resource Restoration program in Priority Watersheds and Job Stabilization. Under this initiative, the agency will assess the health of all of its watersheds, carry out forest restoration in national priority watersheds, and then focus on job creation by utilizing stewardship contracts and putting youth to work in rural areas. This initiative complements the work to be accomplished under the Collaborative Forest Landscape Restoration Fund (CFLRF). These watersheds will be identified and prioritized using State Forest Assessments, watershed conditions, costs and input from local communities. Projects will be selected in areas greater than 10,000 acres. Through this process, the Forest Service will work collaboratively to maintain or improve water quality and watershed function, improve habitat for fish and wildlife, and create local jobs in forest-based communities.

Attached to the end of this statement is a list of the 12 indicators that we plan on using to assess the health of our watersheds under this initiative. Fire regime condition class and percent vegetative cover are two examples. These Watershed Condition Indicators are diagnostic indicators of the health and trend of various biological, chemical, and physical components of aquatic systems and associated terrestrial uplands. The indicators represent the processes or mechanisms by which management actions can potentially affect watersheds, the species which inhabit them, and their riparian functions and ecological processes.

This initiative will yield the following results by the end of FY 2011.

- Funding for projects that will improve the watershed condition class of approximately 100 NFS watersheds that are important to the public.
- Approximately 20 ten-year stewardship contracts offered in targeted areas around the Country that would provide a steady supply of forest products.
- Over 1,000 jobs created, including a focus on jobs for youth in rural areas.
- A map depicting the condition of the National Forest System's approximately 12,000 highest priority watersheds at the start of FY 2011.
- A map depicting the locations and approximate quantities of the biomass that NFS intends to make available over the next ten years.
- Experience with an alternative to litigation through the piloting of a new Appeals process.

Responding to Climate Change

Broad scientific consensus confirms that global climate change is real and that the impacts are altering forests and grasslands, increasing the frequency of disturbance events and diminishing the ecosystem services they provide. Some of the most urgent forest and grassland management problems of the past 20 years— wildfires, changing water regimes, and expanding forest insect infestations—have been driven, in part, by a changing climate; future impacts are likely to be even more severe.[1] Because America's forests and grasslands are vital to our nation, the Forest Service program of work in FY11 will focus on making ecosystems more resistant to climate-related stresses and more resilient to changing conditions. Helping ecosystems adapt to both current and future climates will ensure that they continue to provide the ecosystem services that Americans want and need, including sequestration of the heat-trapping gases that are the main cause of global warming.

The President's Budget will go a long way in supporting and reinforcing the importance of managing forests and grasslands to respond and adapt to changing climate. Our new Integrated Resource Restoration line item is built partially around the notion that we need to adapt to climate change and will provide an outlet for implementation of forest level climate action plans. Further, I'd like to draw your attention to a very small but significant $2 million investment in Urban and Community forests that will result in significant and direct climate benefits by planting trees in the right places in our communities to help sequester carbon and reduce heating and cooling costs. This cost-share program will make use of a prioritization system to maximize the tons of carbon removed from the atmosphere per federal dollar spent.

[1] Backlund, P.; Janetos, A; Schimel, D., lead authors. 2008. *The effects of climate change on agriculture, land resources, water resources, and biodiversity in the United States.* Final report, synthesis and assessment product 4.3. A report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research, Washington, DC. 342 p.

Fuels and Forest Health Treatments

During the average fire season from 2000 to 2009, about 1.3 million acres under Forest Service protection have burned. Communities expanding into the wildland/urban interface (WUI) are compounding the challenges of suppressing wildfire and highlighting the need to focus treatments in the WUI. The Forest Service has a major role to play in reducing the threat of wildfire to homes and communities by reducing hazardous fuels and restoring forest and grassland health.

In FY11, the Forest Service will direct $349 million to reducing hazardous fuels, treating 1.6 million acres in the WUI. The agency will focus areas for treatment in partnership with communities using their community wildfire protection plans (CWPP), resulting in a doubling of the acres to be treated in areas identified in CWPPs over what is planned for FY 2010. This intense focus on the WUI is part of the initiative to responsibly budget for fires. Fires in the interface present the greatest risk to communities and firefighters, are the most expensive, and are the most complex to suppress. By treating high-priority areas in the WUI, the Forest Service will reduce the threat of large wildfires and increase the effectiveness of suppression actions, thereby protecting communities, reducing risks to firefighters and the public, and lowering the costs of large wildfires.

Fire Suppression and Preparedness

The FY11 President's Budget request continues to reflect the Presidential urgency to responsibly budget for wildfire. It provides $2.4 billion for managing wildland fire, including a more accurate accounting of preparedness costs while continuing full funding of the 10-year average for suppression costs. To enhance accountability for fire suppression, the budget proposes managing fire suppression by establishing three separate accounts. All fire suppression costs would be paid out of the fire suppression account, initially funded at $595 million. This level would cover the costs of initial and smaller extended attack operations consistent with our target of maintaining a 98 percent success rate. In addition, the budget requests $291 million for the FLAME account. Funds from this account would be available for larger, more complex fires that escape initial attack. The budget outlines a new approach to risk management and fire spending accountability, including the process for FLAME funds availability, requiring a formal risk decision by the Secretary of Agriculture before funds can be transferred from FLAME into the suppression account.

In addition to fully covering the anticipated suppression costs, $282 million is proposed for a Presidential Wildland Fire Contingency Reserve. These funds would be available if the Nation experiences an exceptional fire season and the Forest Service anticipates exhausting the amounts appropriated for both the suppression and FLAME funds. The Presidential Contingency account reduces the risk that the Forest Service would need to borrow from other programs to pay for the costs of fire suppression. In such an event, increased accountability for fire spending requires a Presidential Declaration certifying the Forest Service is operating in an effective and accountable manner with all funds previously released before Contingency Funds would be made available. The FLAME and Presidential Contingency accounts complement each other in providing a higher level of accountability for fire spending and reducing the risk that funds will need to be transferred from other mission critical programs to support the costs of fire suppression.

I would like to thank the members of this subcommittee and their colleagues for the work they put in this past year in crafting and passing legislation for the FLAME Wildfire Suppression Reserve Fund for the Forest Service. In the past, large fire seasons have resulted in funding transfers from other Forest Service accounts to the detriment of critical Forest Service work. Funding of the FLAME Wildfire Suppression Reserve Fund and the Presidential Wildland Fire Contingency Reserve in the FY11 budget will enable critical Forest Service activities to proceed, including fuels and forest health treatments in the wildland-urban interface (WUI).

The FY11 budget also contains a significant change by realigning Preparedness and Suppression funding, shifting readiness costs from the Suppression account into Preparedness. This structure provides better transparency by realigning costs that were shifted into the Suppression account beginning in FY 2005. Consistent with congressional direction, these program readiness costs have been moved back into the Preparedness with no net change in resource availability from FY10. In sum, the President's Budget will promote safe, effective, and accountable outcomes from investments made in managing fire on a landscape scale.

Thriving Rural Communities

The Secretary's vision for 2010 and beyond calls for building a forest restoration economy that generates green jobs and rural prosperity. In FY11, the Forest Service will continue to develop new ways of bringing jobs and economic activity to rural communities. The agency will build on 2 years of funding and project success under the American Recovery and Reinvestment Act (ARRA) of 2009. ARRA projects bring jobs and economic stimulus to areas hit hardest by the national recession, including many forest-based communities. For example, the ARRA-funded Huron Fuels Reduction project in northeastern Michigan has brought $3.9 million to an area hit hard by the economic recession, and created over 50 jobs on fuels reduction crews for unemployed or underemployed members of the local communities. Many ARRA projects address high-priority forestry needs, such as fuels and forest health treatments and biomass utilization. Our involvement has helped to stimulate collaborative efforts related to restoration, climate change, fire and fuels, and landscape-scale conservation.

The Forest Service will also play an important role in providing expertise to landowners in forest-based communities to help sustain the economic viability of forest stewardship. In addition, an increased focus on restoration, particularly in priority watersheds, will lead to the creation of more jobs in forest-based communities to carry out this high-priority work.

Conclusion

The President's Budget request for FY 2011 addresses the stresses and disturbances, partly caused by climate change, that pose challenges to the health of America's forests and grasslands. We will respond with treatments to priority watersheds identified in a science-based approach and restore their health to enhance their capacity in delivering ecosystem services that Americans want and need. Our restoration treatments will be on a landscape scale, taking an all-lands approach looking across landownership boundaries to solve problems to conservation based on collaboration with State, Tribal, local, private, and other Federal stakeholders to achieve mutual goals. The Forest Service stands ready, working in tandem with other USDA agencies through this budget, to bring health to our forests and enhance the economic vitality of communities. The budget request does not include any funding for any new road construction, allowing us to focus on maintaining existing high-clearance and closed roads. We are using the Travel Management Planning process to guide our efforts in right-sizing the Agency's road system. The President's Budget for the USDA Forest Service also contains funding for many other important items, such $50 million for the Legacy Roads program to help improve water quality and stream conditions, and an increase in the recreation budget that will help rural economies while creating opportunities to reconnect people to forest lands. I look forward to sharing more with you about the budget and working with you to see many of those budget proposals take shape.

Thank you for your time, and I look forward to answering your questions.

Attachment 1: 12 Core Watershed Condition Indicators

AQUATIC PHYSICAL INDICATORS	
1. Water Quality Condition	This indicator addresses the expressed alteration of physical, biological, or chemical impacts to water quality.
2. Water Quantity (Flow regime) Condition	This indicator addresses changes to the natural flow regime with respect to the magnitude, duration, or timing of natural streamflows hydrograph.
3. Stream and Habitat Condition	This indicator addresses stream channel and aquatic habitat condition with respect to habitat fragmentation, aquatic organism passage, wood, streambank stability, channel geometry, and floodplain connectivity.
AQUATIC BIOLOGICAL INDICATORS	
4. Aquatic Biota Condition	This indicator addresses the distribution, structure, and density of native and introduced aquatic fauna.
5. Riparian Vegetation Condition	This indicator addresses the proper functioning condition of riparian vegetation along streams and water bodies.
TERRESTRIAL PHYSICAL INDICATORS	
6. Road and Trail Condition	This indicator addresses the altered hydrologic and sediment regime changes due to the density, location, distribution, and maintenance of the road network.
7. Soil Condition	This indicator addresses alteration to natural soil condition, including erosion, nutrients, productivity, and physical, chemical, and biological characteristics.
TERRESTRIAL BIOLOGICAL INDICATORS	
8. Fire Effects and Regime Condition	This indicator addresses the potential for altered hydrologic and sediment regimes due to vegetation departures from historical ranges of variability.
9. Forest Cover Condition	This indicator addresses the presence/absence of forest cover on lands classified as forest lands and the need to reestablish or restore forest cover.
10 .Rangeland, Grassland, and Open Area Condition	This indicator addresses the vegetative condition of rangelands, grasslands, and open areas.
11. Terrestrial Non-native Invasive Species Condition	This indicator addresses potential impacts to soil and water resources due to terrestrial non-native invasive species.
12. Forest Health Condition	This indicator addresses the condition of forest mortality due to major insects and diseases outbreaks and air pollution.

Exhibit 2

Tomich, J., "Peabody planning Asian coal shipments through Washington," *St. Louis Post-Dispatch* (March 2, 2011)

STLtoday.com

Peabody planning Asian coal shipments through Washington

BY JEFFREY TOMICH • jtomich@post-dispatch.com > 314-340-8320 | Posted: Wednesday, March 2, 2011 12:00 am

Peabody Energy Corp. is joining the controversial race to supply millions of tons of coal to Asian power plants through Pacific Northwest ports.

The coal miner is partnering with Carrix Inc., the largest U.S. container terminal operator, to initially ship as much as 24 million metric tons of coal through a bulk goods terminal planned for northwest Washington.

"We're opening the door to a new era of U.S. exports from the nation's largest and most productive coal region to the world's best market for coal," Gregory H. Boyce, Peabody's chief executive, said in a statement late Monday.

The company did not release financial terms of the agreement. St. Louis-based Peabody, the world's largest private-sector coal producer, has been studying sites to accommodate Asian coal shipments for the past year. Its plans are similar to those being pursued by Creve Coeur-based Arch Coal Inc., which is planning a coal export terminal in southwest Washington in a partnership with and Australia's Millennium Bulk Terminals LLC.

Arch and Peabody have shipped small volumes of Wyoming coal to fast-growing countries like China and India over the past couple of years.

Peabody is looking to exports of Powder River Basin coal to complement its fast-growing Australian mining operations. The company expects the global seaborne coal trade to exceed 1 billion metric tons for the first time this year with most of the demand coming from Asia.

Increasing shipments requires new port space. Most existing coal cargoes to Asia go through British Columbia, where port capacity is limited, or the Gulf Coast, a longer, more expensive trip. No port on the U.S. West Coast has dedicated coal-handling terminals and equipment.

Peabody's coal shipments would go through a terminal being developed near Ferndale, Wash., less than 20 miles from the Canadian border, company spokeswoman Beth Sutton said. The company developing the terminal, Seattle-based SSA Marine, a unit of Carrix, filed a permit application with the state on Monday.

Shipments could begin within a few years, and the terminal could later be expanded to accommodate as much as 48 million tons of coal, plus 6 million to 10 million tons of other dry bulk goods such as grain, potash and iron ore, Sutton said.

The plans are certain to draw scrutiny from environmental groups already challenging a permit for the Millennium Bulk Terminals project at a former aluminum mill near Longview, Wash.

Peabody is looking to exports of Powder River Basin coal to complement its fast-growing Australian mining operations. The company expects the global seaborne coal trade to exceed 1 billion metric tons for the first time this year with most of the demand coming from Asia.

Arch paid $25 million for a 38-percent stake in the project, which could be used to send up to 5 million tons of coal to overseas power plant owners.

The company also has an agreement with the operator of a British Columbia shipping terminal that will enable the shipment of an additional 2 million tons of Powder River Basin coal to Asia.

Critics say plans for shipping millions of tons of American coal to Asia fly in the face of efforts to limit coal use and greenhouse gas emissions in the United States.

Controversy around the Longview project escalated last month following the disclosure of documents indicating Millenium Bulk Terminals may be planning a much larger operation than originally proposed in a state permit application.

Exhibit 3

Excerpts of U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, 1990-2008, EPA 430-R-10-006 (April 15, 2010)

EPA 430-R-11-005

INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990 – 2009

APRIL 15, 2011

U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, DC 20460
U.S.A.

HOW TO OBTAIN COPIES

You can electronically download this document on the U.S. EPA's homepage at <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>. To request free copies of this report, call the National Service Center for Environmental Publications (NSCEP) at (800) 490-9198, or visit the web site above and click on “order online” after selecting an edition.

All data tables of this document are available for the full time series 1990 through 2009, inclusive, at the internet site mentioned above.

FOR FURTHER INFORMATION

Contact Mr. Leif Hockstad, Environmental Protection Agency, (202) 343–9432, hockstad.leif@epa.gov.

Or Mr. Brian Cook, Environmental Protection Agency, (202) 343–9135, cook.brianb@epa.gov.

For more information regarding climate change and greenhouse gas emissions, see the EPA web site at <http://www.epa.gov/climatechange>.

Released for printing: April 15, 2011

Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2009. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports

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[1] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

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

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

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 report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself 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.

[END BOX]

Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[7] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2005, concentrations of these greenhouse gases have increased globally by 36, 148, and 18 percent, respectively (IPCC 2007).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[8] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

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[7] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

[8] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[9,10] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[11] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2009 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO_2 Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly. Since 1990, U.S. emissions have increased at an average annual rate of 0.4 percent.

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[9] Carbon comprises 12/44^{ths} of carbon dioxide by weight.

[10] One teragram is equal to 10^{12} grams or one million metric tons.

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

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2009.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq. or million metric tons CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*

Change, and Forestry (Sink)[a]							
Biomass - Wood[b]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[b]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0

HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.
[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.
[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.
[c] Emissions from International Bunker Fuels are not included in totals.
[d] Small amounts of PFC emissions also result from this source.
Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2009. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.0 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have increased by 1.7 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management and mobile source fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted as a by-product of primary aluminum production and from semiconductor manufacturing, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively. Conversely, N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). From 1990 to 2009, HFCs increased by 88.8 Tg CO_2 Eq. (240.41 percent), PFCs decreased by 15.1 Tg CO_2 Eq. (73.0 percent), and SF_6 decreased by 19.5 Tg CO_2 Eq. (56.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.3 percent of total emissions in 2009. The following sections describe each gas' contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 36 percent (IPCC 2007), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 94.6 percent of CO_2 emissions in 2009. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[12] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2009 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2009. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 20 years, and (2) overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2009, CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease in any year over the twenty-year period.

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily 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. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

[12] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories[a]	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
[a] 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.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 33 percent of CO_2 emissions from fossil fuel combustion in 2009.[13] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2009, transportation emissions rose by 16 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2009. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2009. Both sectors relied heavily on electricity for meeting energy demands, with 70 and 77 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 25 percent since 1990, due to increasing electricity consumption for lighting, heating, air

[13] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 35 percent of U.S. emissions from fossil fuel combustion in 2009.

conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 41 percent of the CO_2 from fossil fuel combustion in 2009. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 95 percent of all coal consumed for energy in the United States in 2009. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production decreased by 24.1 Tg CO_2 Eq. (36.6 percent) from 2008 to 2009, continuing a trend of decreasing emissions from 1990 through 2009 of 57.9 percent (57.7 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2009, CO_2 emissions from cement production decreased by 11.5 Tg CO_2 Eq. (28.4 percent) from 2008. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the last three years. Overall, from 1990 to 2009, emissions from cement production decreased by 12.8 percent, a decrease of 4.3 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 153.5 Tg CO_2 Eq. (17.8 percent) from 1990 through 2009. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 148 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, , agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2009 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- In 2009, CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq., a 3.9 Tg CO_2 Eq. (5.8 percent) increase over 2008 emission levels. The overall decline of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2009 with 221.2 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990. Methane emissions from this source increased 4 percent from 2008 to 2009 due to an increase in production and production wells.
- Enteric Fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2009, enteric fermentation CH_4 emissions were 139.8 Tg CO_2 Eq. (20 percent of total CH_4 emissions), which represents an increase of 7.7 Tg CO_2 Eq. (5.8 percent) since 1990.

- Methane emissions from manure management increased by 55.9 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 17 percent of total CH_4 emissions (117.5 Tg CO_2 Eq.) in 2009. From 1990 to 2009, CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[14] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 18 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, manure management, nitric acid production and stationary fuel combustion, (see Figure ES-9).

Figure ES-9: 2009 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly since 1996 from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990, and emissions from adipic acid production have remained consistently lower than pre-1996 levels since 1998.
- Agricultural soils accounted for approximately 69.2 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the

[14] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-outs required under the Montreal Protocol come into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 85.2 percent (31.0 Tg CO_2 Eq.) from 1990 through 2009, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 54.8 percent (15.6 Tg CO_2 Eq.) from 1990 to 2009, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (9 percent), and 35.7 Tg CO_2 Eq. (9 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10 percent), 24.7 Tg CO_2 Eq. (14 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 143.5 Tg CO_2 Eq. (17 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Energy	5,287.8		6,168.0		6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8		348.8		334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4		4.9		4.4	4.4	4.4	4.4	4.4
Agriculture	383.6		410.6		418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0		36.3		28.6	49.8	47.5	33.2	25.0
Waste	175.2		143.9		144.9	144.4	144.1	149.0	150.5
Total Emissions	**6,181.8**		**7,112.7**		**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-	(861.5)		(576.6)		(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

Use Change, and Forestry (Sinks)*							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87 percent of total U.S. greenhouse gas emissions in 2009.

Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4 percent of U.S. greenhouse gas emissions in 2009.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2009.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2009, accounting for 69 percent. In 2009, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	1990		2000		2005	2006	2007	2008	2009
Forest Land Remaining Forest Land[1]	(681.1)		(378.3)		(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)		(30.2)		(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2		2.4		5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)		(52.6)		(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)		(27.2)		(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)		(77.5)		(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)		(13.2)		(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**		**(576.6)**		**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. The application of crushed limestone and dolomite to managed land (i.e., liming of agricultural soils) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of 11 percent relative to 1990. The application of synthetic fertilizers to forest and settlement soils in 2009 resulted in direct N_2O emissions of 1.9 Tg CO_2 Eq. Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils increased by 55 percent since 1990. Forest fires resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. in 2009. CO_2 and N_2O emissions from peatlands totaled 1.1 Tg CO_2 Eq. and less than 0.01 Tg CO_2 Eq. in 2009, respectively.

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990		2000		2005	2006	2007	2008	2009
CO_2	**8.1**		**8.8**		**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7		4.3		4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4		3.2		3.5	3.7	3.7	3.6	3.6

Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for just over 78 percent of this chapter's emissions, and 17 percent of total U.S. CH_4 emissions.[15] Additionally, wastewater treatment accounts for 20 percent of Waste emissions, 4 percent of U.S. CH_4 emissions, and 2 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.7 Tg CO_2 Eq. and 1.8 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.3 percent of total U.S. greenhouse gas emissions in 2009.

Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2009.

Figure ES-13: Emissions Allocated to Economic Sectors

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5

[15] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Total Emissions	6,181.8		7,112.7		7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)		(576.6)		(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**		**6,536.1**		**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial sector accounted for 6 percent of emissions while the residential sector accounted for 5 percent of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[16] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, Industrial activities account for the largest share of U.S. greenhouse gas emissions (29 percent) in 2009. Transportation is the second largest contributor to total U.S. emissions (28 percent). The commercial and residential sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2009. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2009.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990		2000		2005	2006	2007	2008	2009
Industry	2,238.3		2,314.4		2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3		1,935.8		2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7		1,135.8		1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8		1,162.2		1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0		518.4		522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7		46.0		58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**		**7,112.7**		**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change,	(861.5)		(576.6)		(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

[16] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

and Forestry (Sinks)									
Net Emissions (Sources and Sinks)	**5,320.3**		**6,536.1**		**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**	**Growth Rate**[a]
GDP[b]	100		140		157	162	165	165	160	2.5%
Electricity Consumption[c]	100		127		134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100		117		119	117	119	116	108	0.5%
Energy Consumption[c]	100		116		118	118	120	118	112	0.6%
Population[d]	100		113		118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100		115		117	116	117	114	107	0.4%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[17] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[18] which are regulated under the Clean Air Act. Table ES- 10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES- 10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0

[17] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[18] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[19] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2009 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2009 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[19] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

[BEGIN BOX]

Box ES-3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors." In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2009) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

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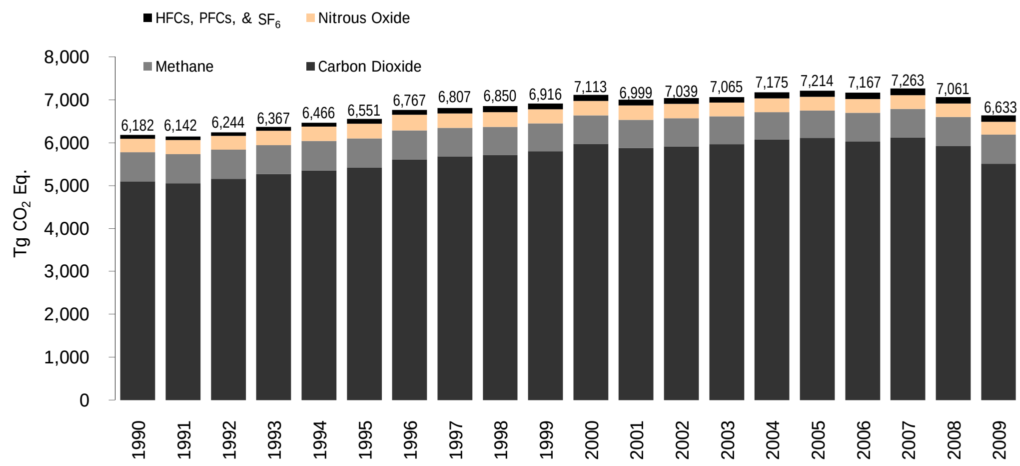


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

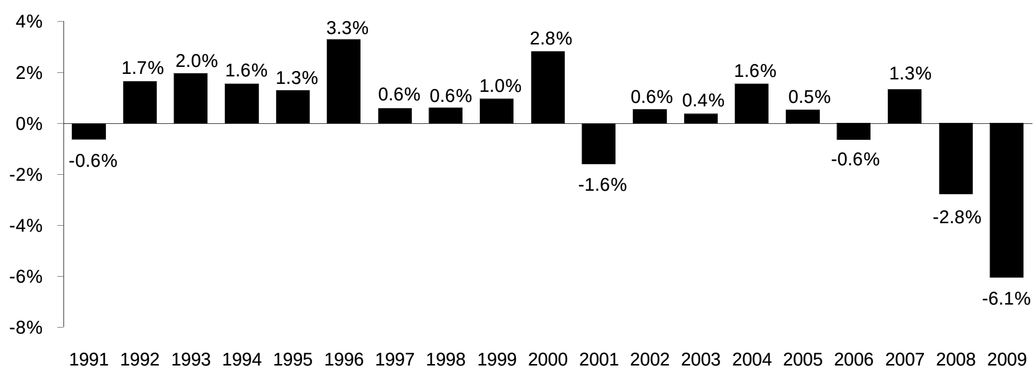


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

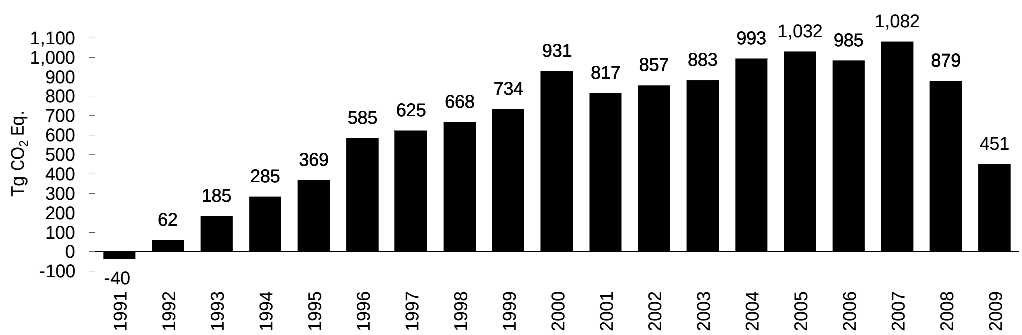


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

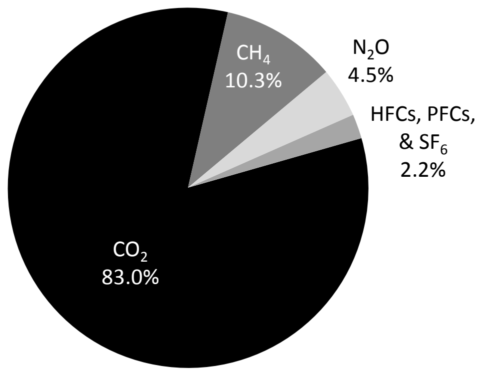


Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

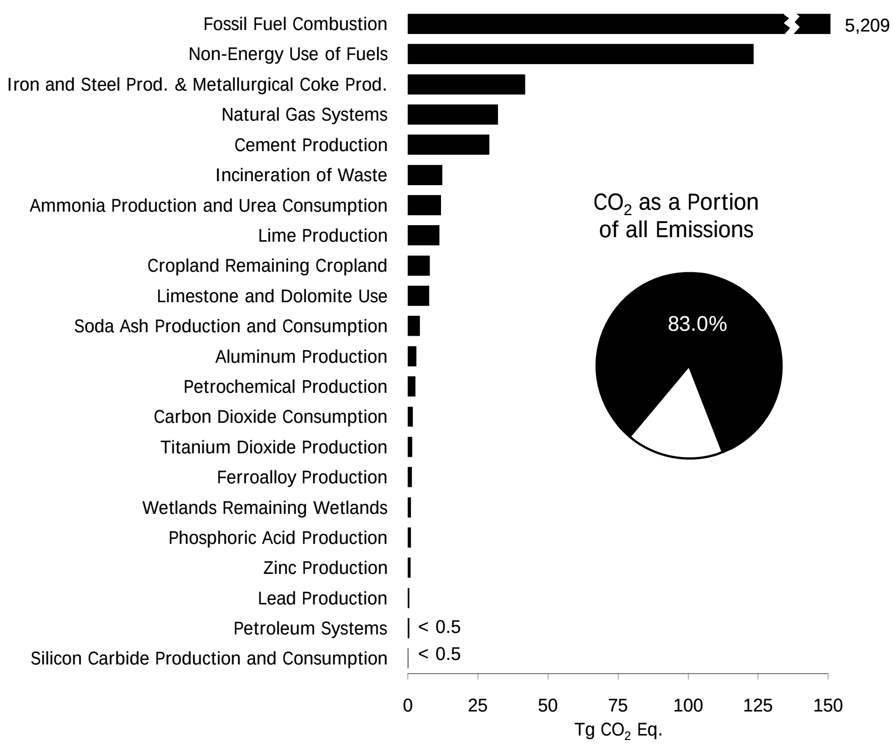


Figure ES-5: 2009 Sources of CO_2 Emissions

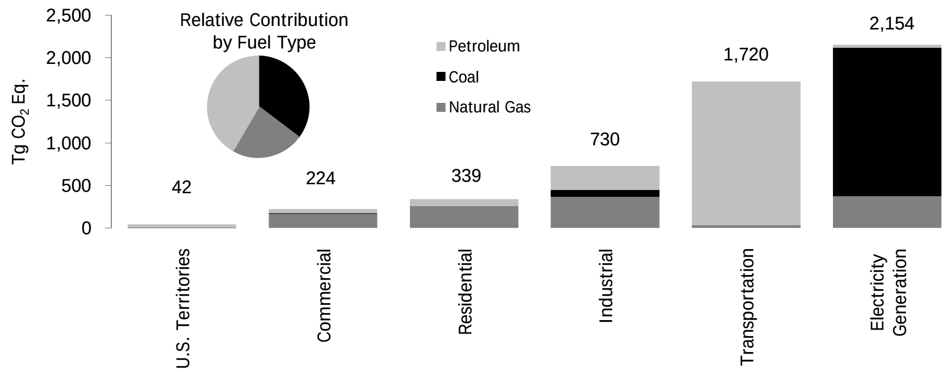


Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

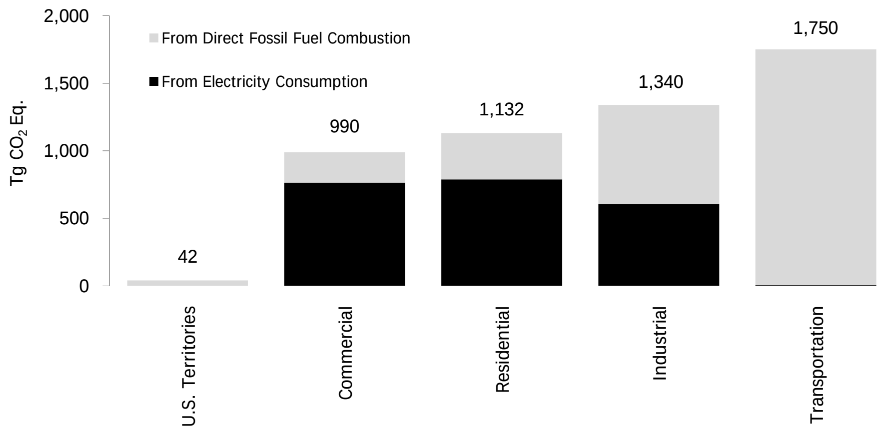


Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

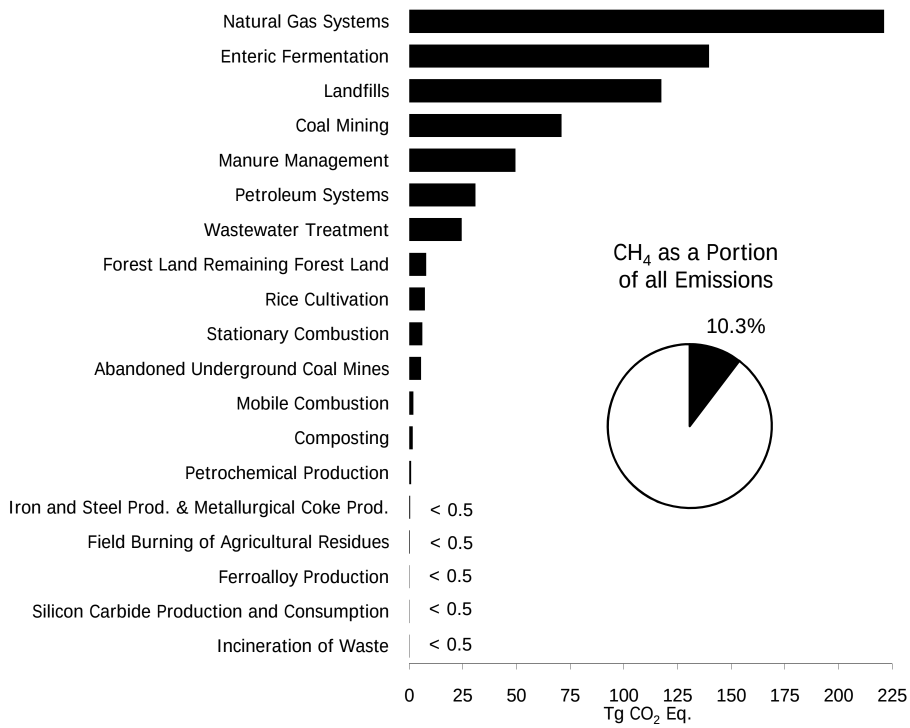


Figure ES-8: 2009 Sources of CH_4 Emissions

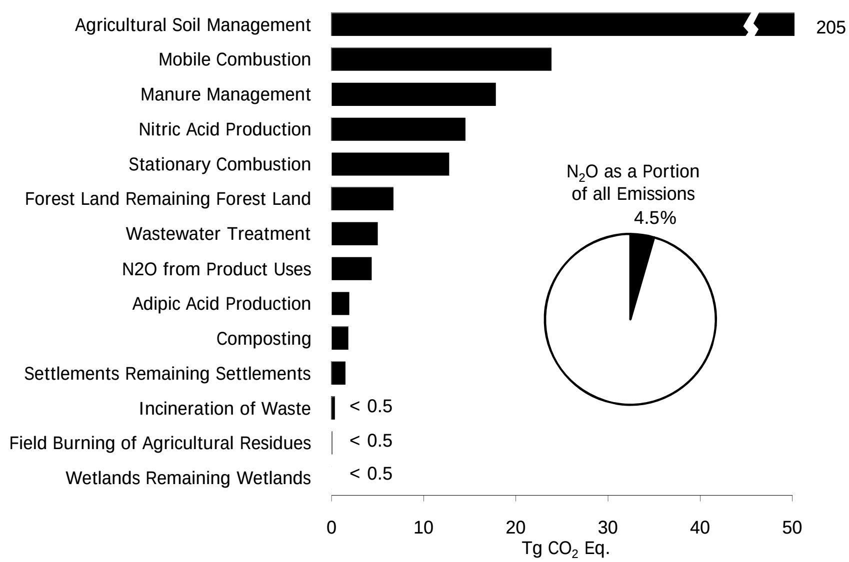


Figure ES-9: 2009 Sources of N_2O Emissions

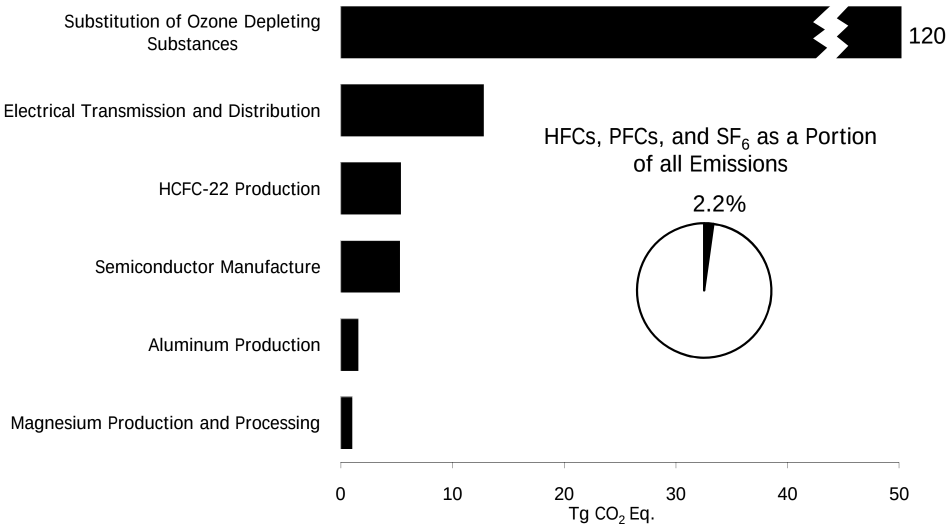
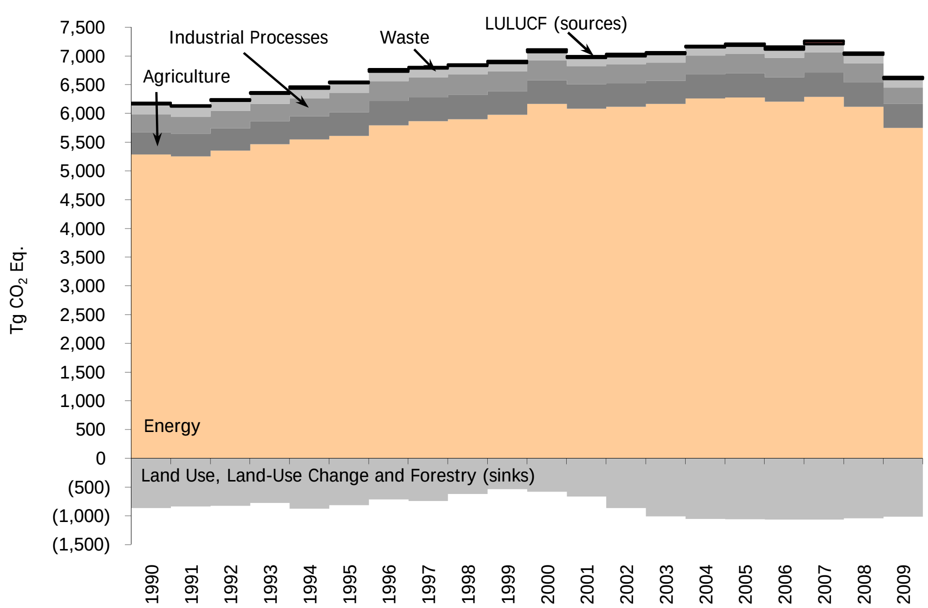


Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

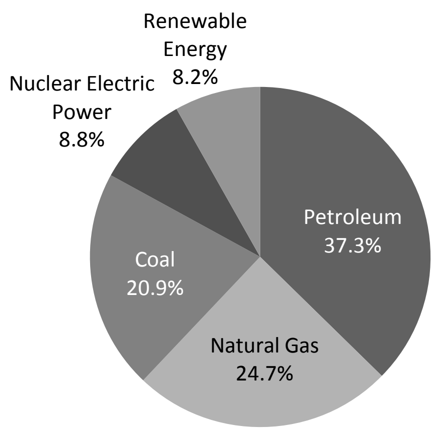


Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

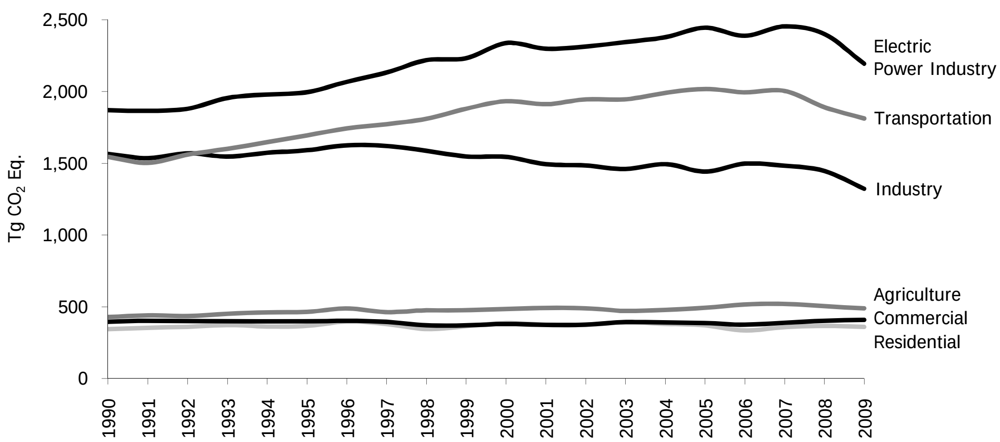


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

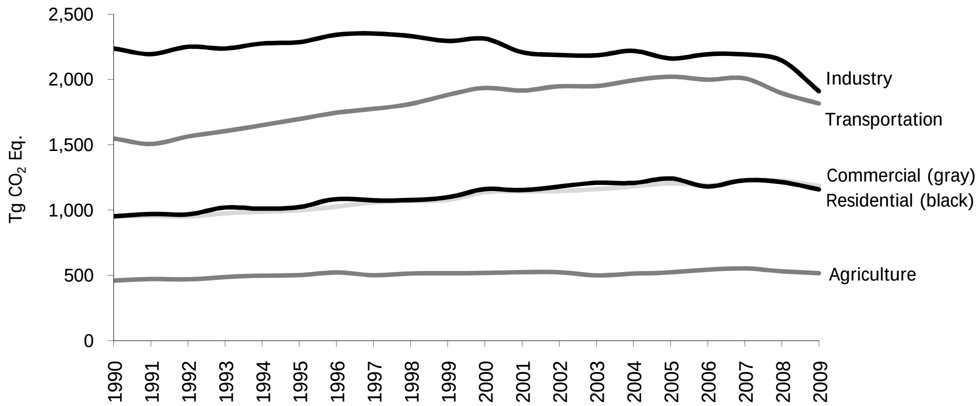


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors
Note: Does not include U.S. Territories.

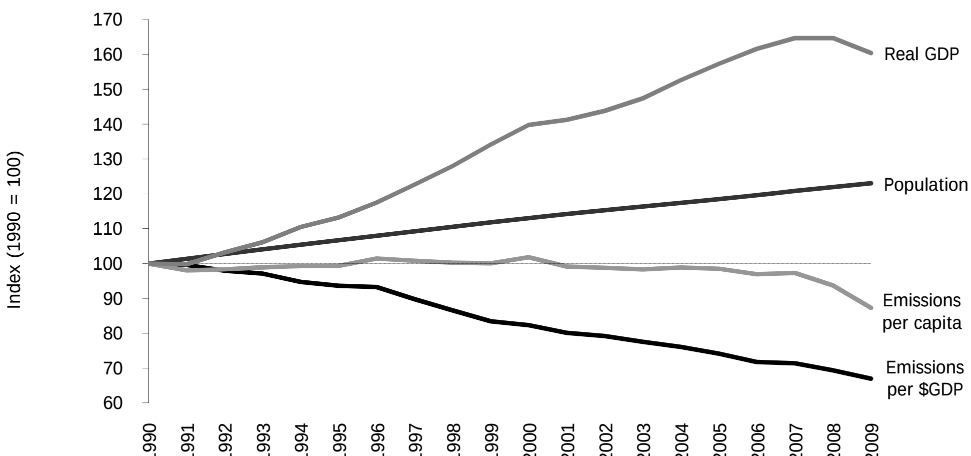


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

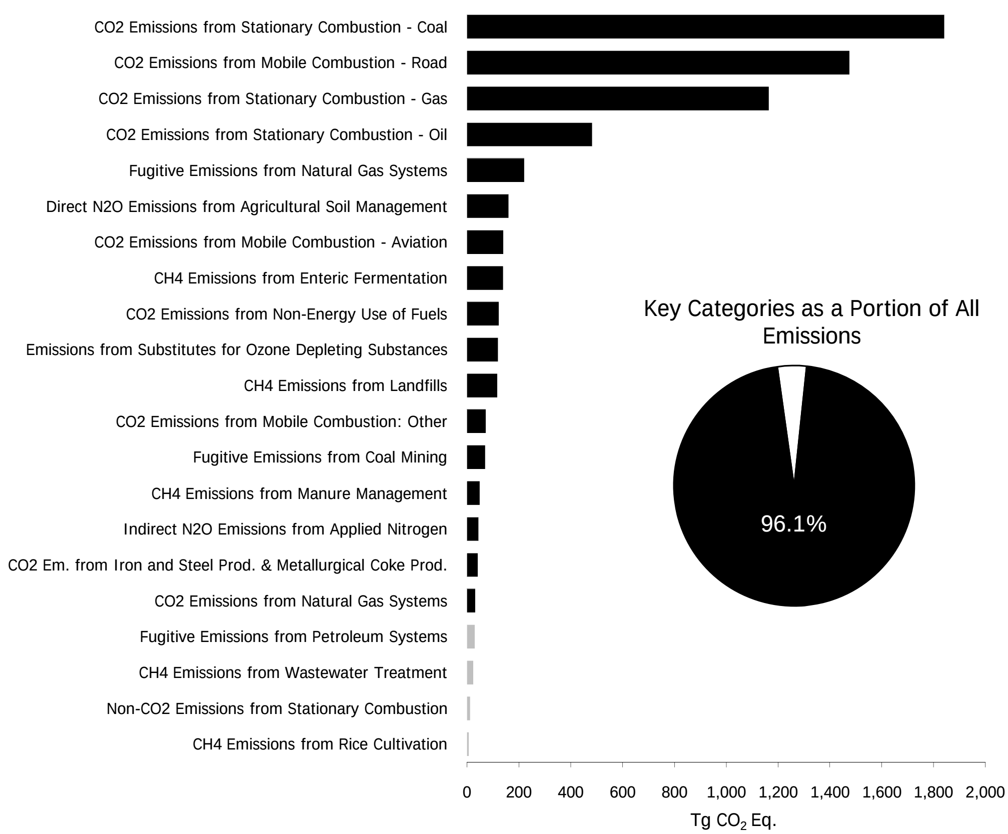


Figure ES-16: 2009 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86.7 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis[52] in 2009. This included 98, 49, and 13 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (5.6 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 30,398 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[53] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, and mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States.

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,751.1 Tg CO_2 Eq. in 2009, an increase of 9 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990		2000		2005	2006	2007	2008	2009
CO_2	**4,903.2**		**5,781.3**		**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4		5,594.8		5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8		2,296.9		2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9		1,809.5		1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5		851.1		823.1	848.2	842.0	802.9	730.4
Residential	338.3		370.7		357.9	321.5	342.4	348.2	339.2
Commercial	219.0		230.8		223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9		35.9		50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6		144.9		143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6		29.9		29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0		11.1		12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6		0.5		0.5	0.5	0.5	0.5	0.5
*Biomass - Wood**	*215.2*		*218.1*		*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
*International Bunker Fuels**	*111.8*		*98.5*		*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
*Biomass – Ethanol**	*4.2*		*9.4*		*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**		**318.6**		**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8		209.3		190.4	217.7	205.2	211.8	221.2

[52] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[53] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010).

Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.
* 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: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903,171**	**5,781,303**	**5,939,434**	**5,842,464**	**5,938,203**	**5,752,327**	**5,377,271**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Petroleum Systems	555	534	490	488	474	453	463
*Biomass -Wood**	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
*International Bunker Fuels**	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
*Biomass - Ethanol**	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**15,590**	**15,171**	**13,872**	**15,202**	**14,634**	**15,408**	**16,037**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**185**	**220**	**168**	**156**	**146**	**131**	**120**
Mobile Combustion	142	172	119	108	98	84	77
Stationary Combustion	41	47	47	47	47	46	41
Incineration of Waste	2	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	*3*	*4*	*4*	*4*	*4*

+ Does not exceed 0.05 Tg CO_2 Eq.
* 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.

3.1. Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 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 CO_2 from fossil fuel combustion also differ from the estimation of CH_4 and N_2O 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 CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Tg CO_2 Eq.)

Gas	1990		2000		2005	2006	2007	2008	2009
CO_2	4,738.4		5,594.8		5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
CH_4	12.1		10.0		9.1	8.5	8.7	8.5	8.1
N_2O	56.8		67.7		51.7	48.1	44.9	40.4	36.7
Total	**4,807.3**		**5,627.6**		**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding.

Table 3-4: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Gg)

Gas	1990		2000		2005	2006	2007	2008	2009
CO_2	4,738,422		5,594,848		5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
CH_4	577		476		431	405	413	407	386
N_2O	183		219		167	155	145	130	118

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2009, CO_2 emissions from fossil fuel combustion decreased by 6.4 percent relative to the previous year. This decrease represents the largest annual decrease in CO_2 emissions from fossil fuel combustion for the twenty-year period.[54] The decrease in CO_2 emissions from fossil fuel combustion was a result of multiple factors including: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price natural gas decreased significantly; and (3) an increase in non-fossil fuel consumption by approximately 2 percent. In 2009, CO_2 emissions from fossil fuel combustion were 5,209.0 Tg CO_2 Eq., or almost 10 percent above emissions in 1990 (see Table 3-5).[55]

Table 3-5: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990		2000		2005	2006	2007	2008	2009
Coal	**1,718.4**		**2,065.5**		**2,112.3**	**2,076.5**	**2,106.0**	**2,072.5**	**1,841.0**
Residential	3.0		1.1		0.8	0.6	0.7	0.7	0.6
Commercial	12.0		8.8		9.3	6.2	6.7	6.5	5.8
Industrial	155.3		127.3		115.3	112.6	107.0	102.6	83.4
Transportation	NE		NE		NE	NE	NE	NE	NE
Electricity Generation	1,547.6		1,927.4		1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
U.S. Territories	0.6		0.9		3.0	3.4	4.3	3.3	3.5
Natural Gas	**1,000.6**		**1,217.4**		**1,159.0**	**1,141.3**	**1,218.0**	**1,226.0**	**1,200.9**

[54] This decrease also represents the largest absolute and percentage decrease since the beginning of EIA's record of annual energy consumption data, beginning in 1949 (EIA 2010a).

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

Residential	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Commercial	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Industrial	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Transportation	36.0	35.6	33.1	33.1	35.3	36.8	36.3
Electricity Generation	175.3	280.8	318.8	338.0	371.3	361.9	373.1
U.S. Territories	NO	0.7	1.3	1.4	1.4	1.6	1.5
Petroleum	**2,019.0**	**2,311.6**	**2,481.5**	**2,434.9**	**2,432.4**	**2,267.1**	**2,166.7**
Residential	97.4	98.8	94.9	83.6	84.6	83.1	81.4
Commercial	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Industrial	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Transportation	1,449.9	1,773.9	1,863.5	1,845.0	1,858.7	1,753.1	1,683.4
Electricity Generation	97.5	88.4	99.2	54.4	53.9	39.2	32.9
U.S. Territories	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Geothermal*	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**

NE (Not estimated)
NO (Not occurring)
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Trends in CO_2 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).

CO_2 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.[56] 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 CO_2 Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2005 to 2006		2006 to 2007		2007 to 2008		2008 to 2009		Total 2009
Electricity Generation	Coal	-30.1	-1.5%	33.6	1.7%	-27.9	-1.4%	-211.7	-10.8%	1,747.6
Electricity Generation	Natural Gas	19.2	6.0%	33.3	9.9%	-9.3	-2.5%	11.1	3.1%	373.1
Electricity Generation	Petroleum	-44.8	-45.2%	-0.5	-0.9%	-14.7	-27.2%	-6.3	-16.0%	32.9
Transportation [a]	Petroleum	-18.5	-1.0%	13.7	0.7%	-105.6	-5.7%	-69.7	-4.0%	1,683.4
Residential	Natural Gas	-24.9	-9.5%	19.7	8.3%	7.4	2.9%	-7.3	-2.8%	257.2
Commercial	Natural Gas	-9.1	-5.6%	10.2	6.6%	6.2	3.8%	-2.3	-1.3%	167.9
Industrial	Coal	-2.8	-2.4%	-5.6	-5.0%	-4.4	-4.1%	-19.2	-18.7%	83.4
Industrial	Natural Gas	-3.1	-0.8%	11.3	3.0%	2.0	0.5%	-26.0	-6.6%	365.0
All Sectors [b]	**All Fuels [b]**	**-100.1**	**-1.7%**	**103.6**	**1.8%**	**-190.8**	**-3.3%**	**-356.9**	**-6.4%**	**5,209.0**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

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

In the United States, 83 percent of the energy consumed in 2009 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 (9 percent) and by a variety of renewable energy sources[57] (8 percent), primarily hydroelectric power and biofuels (EIA 2010). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 42 percent of total fossil fuel based energy consumption in 2009. Natural gas and coal followed in order of importance, accounting for approximately 32 and 27 percent of total 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 2010).

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

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

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

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 CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[58] These other C containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2009, weather conditions remained constant in the winter and slightly cooler in the summer compared to 2008, as heating degree days decreased slightly and cooling degree days decreased by 3.8 percent. Winter conditions were relatively constant in 2009 compared to 2008, and the winter was slightly warmer than normal, with heating degree days in the United States 0.7 percent below normal (see Figure 3-6). Summer conditions were slightly cooler in 2009 compared to 2008, and summer temperatures were slightly cooler than normal, with cooling degree days 1 percent below normal (see Figure 3-7) (EIA 2010).[59]

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2009)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2009)

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

[58] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

[59] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect 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).

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[60]) of existing plants in 2009 remained high at just over 90 percent. Electricity output by hydroelectric power plants increased in 2009 by approximately 6.8 percent. Electricity generated by nuclear plants in 2009 provided nearly 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2010). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2009)

[END BOX]

Fossil Fuel Combustion Emissions by Sector

In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector.

Table 3-7: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,829.5**	**2,307.5**	**2,413.2**	**2,357.2**	**2,423.8**	**2,371.7**	**2,163.7**
CO_2	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
CH_4	0.6	0.7	0.7	0.7	0.7	0.7	0.7
N_2O	8.1	10.0	10.3	10.1	10.3	10.1	9.0
Transportation	**1,534.6**	**1,866.0**	**1,936.0**	**1,914.1**	**1,926.5**	**1,818.1**	**1,745.5**
CO_2	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
CH_4	4.7	3.4	2.5	2.3	2.2	2.0	2.0
N_2O	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Industrial	**851.2**	**855.9**	**827.5**	**852.8**	**846.5**	**807.0**	**734.1**
CO_2	846.5	851.1	823.1	848.2	842.0	802.9	730.4
CH_4	1.5	1.6	1.4	1.5	1.4	1.3	1.2
N_2O	3.2	3.2	3.0	3.1	3.0	2.8	2.5
Residential	**343.8**	**375.0**	**362.2**	**325.4**	**346.6**	**352.6**	**343.4**
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4
N_2O	1.1	0.9	0.9	0.8	0.9	0.9	0.9
Commercial	**220.2**	**232.1**	**224.8**	**209.7**	**220.6**	**225.4**	**225.2**
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0
CH_4	0.9	0.9	0.9	0.8	0.9	0.9	0.9
N_2O	0.4	0.4	0.4	0.3	0.3	0.3	0.3
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

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

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the

[60]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 (2010b).

indirect greenhouse gases NO_x, CO, and NMVOCs.[61] CH_4 and N_2O 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. N_2O 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. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O 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. N_2O 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. CO 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. CH_4 and NMVOC emissions from motor vehicles are a function of the CH_4 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 CH_4 and N_2O from transportation.[62] Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method of distributing emissions assumes that 564 combustion sources focus on the alternative method as presented in Table 3-8.

Table 3-8: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990		2000		2005	2006	2007	2008	2009
Transportation	**1,537.6**		**1,869.5**		**1,940.8**	**1,918.6**	**1,931.5**	**1,822.8**	**1,750.0**
CO_2	1,489.0		1,813.0		1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
CH_4	4.7		3.4		2.5	2.4	2.2	2.0	2.0
N_2O	44.0		53.2		37.0	33.6	30.3	26.2	23.9
Industrial	**1,541.2**		**1,649.3**		**1,567.9**	**1,568.1**	**1,579.7**	**1,525.1**	**1,340.1**
CO_2	1,533.2		1,640.8		1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
CH_4	1.8		1.8		1.7	1.7	1.6	1.6	1.4
N_2O	6.3		6.7		6.2	6.2	6.1	5.8	5.0
Residential	**939.7**		**1,140.9**		**1,222.9**	**1,160.1**	**1,206.7**	**1,190.4**	**1,131.6**
CO_2	931.4		1,133.1		1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
CH_4	4.6		3.6		3.7	3.3	3.6	3.7	3.6
N_2O	3.7		4.2		4.6	4.4	4.5	4.5	4.2
Commercial	**760.8**		**976.8**		**1,032.2**	**1,012.4**	**1,046.0**	**1,036.5**	**990.3**
CO_2	757.0		972.1		1,027.2	1,007.6	1,041.1	1,031.6	985.7
CH_4	1.0		1.1		1.1	1.1	1.1	1.2	1.1
N_2O	2.8		3.6		3.8	3.8	3.8	3.8	3.5
U.S. Territories*	**28.0**		**36.0**		**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**		**5,672.6**		**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

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

[61] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

[62] Separate calculations were performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

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 CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO_2 from fossil fuel combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. CH_4 and N_2O 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. N_2O 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. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO_2 Emissions from Stationary Fossil Fuel Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990		2000		2005	2006	2007	2008	2009
Electricity Generation	**1,820.8**		**2,296.9**		**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**
Coal	1,547.6		1,927.4		1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
Natural Gas	175.3		280.8		318.8	338.0	371.3	361.9	373.1
Fuel Oil	97.5		88.4		99.2	54.4	53.9	39.2	32.9
Geothermal	0.4		0.4		0.4	0.4	0.4	0.4	0.4
Industrial	**846.5**		**851.1**		**823.1**	**848.2**	**842.0**	**802.9**	**730.4**
Coal	155.3		127.3		115.3	112.6	107.0	102.6	83.4
Natural Gas	409.1		457.2		380.8	377.7	389.0	391.0	365.0
Fuel Oil	282.1		266.6		326.9	357.9	346.0	309.3	282.0
Commercial	**219.0**		**230.8**		**223.5**	**208.6**	**219.4**	**224.2**	**224.0**
Coal	12.0		8.8		9.3	6.2	6.7	6.5	5.8
Natural Gas	142.1		172.5		162.9	153.8	164.0	170.2	167.9
Fuel Oil	64.9		49.6		51.3	48.5	48.7	47.4	50.3
Residential	**338.3**		**370.7**		**357.9**	**321.5**	**342.4**	**348.2**	**339.2**
Coal	3.0		1.1		0.8	0.6	0.7	0.7	0.6
Natural Gas	238.0		270.7		262.2	237.3	257.0	264.4	257.2
Fuel Oil	97.4		98.8		94.9	83.6	84.6	83.1	81.4
U.S. Territories	**27.9**		**35.9**		**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Coal	0.6		0.9		3.0	3.4	4.3	3.3	3.5
Natural Gas	NO		0.7		1.3	1.4	1.4	1.6	1.5
Fuel Oil	27.2		34.2		45.7	45.5	40.4	35.0	36.7
Total	**3,252.5**		**3,785.3**		**3,856.6**	**3,775.0**	**3,862.8**	**3,776.0**	**3,489.3**

* U.S. Territories are not apportioned by sector, and emissions are from all fuel combustion sources (stationary and mobile) are presented in this table.

Table 3-10: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990		2000		2005	2006	2007	2008	2009
Electricity Generation	**0.6**		**0.7**		**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3		0.4		0.4	0.4	0.4	0.4	0.4
Fuel Oil	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
Industrial	**1.5**		**1.6**		**1.4**	**1.5**	**1.4**	**1.3**	**1.2**
Coal	0.3		0.3		0.3	0.3	0.2	0.2	0.2
Fuel Oil	0.2		0.1		0.2	0.2	0.2	0.2	0.1
Natural Gas	0.2		0.2		0.1	0.1	0.1	0.1	0.1
Wood	0.9		1.0		0.9	0.9	0.8	0.8	0.7
Commercial	**0.9**		**0.9**		**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+		+		+	+	+	+	+
Fuel Oil	0.2		0.1		0.2	0.1	0.1	0.1	0.1
Natural Gas	0.3		0.3		0.3	0.3	0.3	0.3	0.3
Wood	0.4		0.4		0.4	0.4	0.4	0.4	0.4
Residential	**4.4**		**3.4**		**3.4**	**3.1**	**3.4**	**3.5**	**3.4**
Coal	0.2		0.1		0.1	+	+	+	+
Fuel Oil	0.3		0.3		0.3	0.3	0.3	0.3	0.3
Natural Gas	0.4		0.5		0.5	0.4	0.5	0.5	0.5
Wood	3.5		2.5		2.6	2.3	2.6	2.7	2.6
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
Natural Gas	+		+		+	+	+	+	+
Wood	+		+		+	+	+	+	+
Total	**7.4**		**6.6**		**6.6**	**6.2**	**6.5**	**6.5**	**6.2**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 3-11: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990		2000		2005	2006	2007	2008	2009
Electricity Generation	**8.1**		**10.0**		**10.3**	**10.1**	**10.2**	**10.1**	**9.0**
Coal	7.6		9.4		9.7	9.5	9.7	9.6	8.5
Fuel Oil	0.2		0.2		0.2	0.1	0.1	0.1	0.1
Natural Gas	0.1		0.2		0.2	0.2	0.2	0.2	0.2
Wood	0.2		0.2		0.2	0.2	0.2	0.2	0.2
Industrial	**3.2**		**3.2**		**3.0**	**3.1**	**3.0**	**2.8**	**2.5**
Coal	0.8		0.6		0.6	0.6	0.5	0.5	0.4
Fuel Oil	0.5		0.4		0.5	0.6	0.6	0.5	0.4
Natural Gas	0.2		0.3		0.2	0.2	0.2	0.2	0.2
Wood	1.7		1.9		1.7	1.7	1.7	1.6	1.4
Commercial	**0.4**		**0.4**		**0.4**	**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	**1.1**		**0.9**		**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+		+		+	+	+	+	+
Fuel Oil	0.3		0.3		0.3	0.2	0.2	0.2	0.2
Natural Gas	0.1		0.2		0.1	0.1	0.1	0.1	0.1
Wood	0.7		0.5		0.5	0.5	0.5	0.5	0.5
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	+		+		+	+	+	+	+
Wood	+		+		+	+	+	+	+
Total	**12.8**		**14.6**		**14.7**	**14.4**	**14.6**	**14.2**	**12.8**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. CH_4 and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.4 percent, respectively.[63] Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2009. CH_4 and N_2O from electricity generation represented 8 and 25 percent of emissions from CH_4 and N_2O emissions from fossil fuel combustion in 2009, 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).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, 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,[64] while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

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 2009 decreased approximately 1.2 percent and 1.0 percent, respectively. The trend in the commercial and residential sectors can largely be attributed to the decreased carbon intensity in the fuels used to generate electricity for these sectors. In addition, electricity consumption in both sectors decreased as a result of the less energy-intensive weather conditions compared to 2008. In 2009, the amount of electricity generated (in kWh) decreased by 4 percent from the previous year. This decline was due to the economic downturn, a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly, and an increase in non-fossil fuel sources used to generate electricity. As a result, CO_2 emissions from the electric power sector decreased by 8.8 percent as the consumption of coal and petroleum for electricity generation decreased by 10.8 percent and 16.6 percent, respectively, in 2009 and the consumption of natural gas for electricity generation, increased by 3.1 percent. The decrease in C intensity of the electricity supply (see Table 3-15) was the result of a decrease in the carbon intensity of fossil fuels consumed to generate electricity and an increase in renewable generation of 5 percent spurred by a 28 percent increase in wind-generated electricity.

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[63] Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-7and Table 3-8, the percentages for CH_4 and N_2O exclude U.S. territory estimates.

[64] 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).

Industrial Sector

The industrial sector accounted for 14 percent of CO_2 emissions from fossil fuel combustion, 15 percent of CH_4 emissions from fossil fuel combustion, and 7 percent of N_2O emissions from fossil fuel combustion. CO_2, CH_4, and N_2O 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 2010 and EIA 2009c).

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.[65] 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 2008 to 2009, total industrial production and manufacturing output decreased by 9.3 and 10.9 percent, respectively (FRB 2010). Over this period, output decreased across all production indices for Food, Petroleum Refineries, Chemicals, Paper, Primary Metals, and Nonmetallic Mineral Products (see Figure 3-10).

Figure 3-10: Industrial Production Indices (Index 2002=100)

Despite the growth in industrial output (41 percent) and the overall U.S. economy (60 percent) from 1990 to 2009, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 13.7 percent over that time. 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 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,340.1 Tg CO_2 Eq., or approximately 12.1 percent below 2008 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 7 and 4 percent of CO_2 emissions from fossil fuel combustion, 42 and 11 percent of CH_4 emissions from fossil fuel combustion, and 2 and 1 percent of N_2O 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 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,131.6 Tg CO_2 Eq. and 990.3Tg CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from the residential and commercial sectors decreased by 4.9 and 4.5 percent from 2008 to 2009, 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).

Emissions from natural gas consumption represent about 76 and 75 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. In 2009, natural gas CO_2 emissions from the residential and commercial sectors decreased by 2.8 percent and 1.3 percent, respectively. The decrease in natural gas emissions in both sectors is a result of less energy-intensive weather conditions in the United States compared to

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[65] 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.

2008.

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 the Methodology section for CO_2 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, CO_2, CH_4, and N_2O 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

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.

The transportation end-use sector accounted for 1,745.5 Tg CO_2 Eq. in 2009, which represented 33 percent of CO_2 emissions, 24 percent of CH_4 emissions, and 65 percent of N_2O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 123.1 Tg CO_2 in 2009; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 64 percent of CO_2 emissions, medium- and heavy-duty trucks 20 percent, commercial aircraft 6 percent, and other sources 9 percent. Light-duty truck CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation, CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO_2 emissions by mode and fuel type.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

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 CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (235.1 Tg) between 1990 and 2009, an annualized increase of 0.8 percent. The 4 percent decline in emissions between 2008 and 2009 followed the previous year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil.[66] Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 in the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,111.7 Tg in 2009, an increase of 17 percent (161.3 Tg) from 1990. CO_2 emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 6 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 52 percent and declined to 40 percent in 2009.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2008

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2008

Light-duty truck[67] CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation[68], CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

Table 3-12: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990		2000		2005	2006	2007	2008	2009
Gasoline	**983.7**		**1,135.0**		**1,187.8**	**1,178.2**	**1,181.2**	**1,130.3**	**1,125.7**
Passenger Cars	621.4		640.6		658.0	635.0	628.7	594.0	593.3
Light-Duty Trucks	309.1		446.4		478.7	491.5	500.1	486.5	485.9
Medium- and Heavy-Duty Trucks[b]	38.7		36.0		34.9	35.5	36.1	33.7	30.6
Buses	0.3		0.4		0.4	0.4	0.4	0.4	0.3
Motorcycles	1.7		1.8		1.6	1.9	2.1	2.1	2.1
Recreational Boats	12.4		9.8		14.1	14.0	13.9	13.5	13.4
Distillate Fuel Oil (Diesel)	**262.9**		**402.5**		**451.8**	**470.3**	**476.3**	**443.5**	**402.5**
Passenger Cars	7.9		3.7		4.2	4.1	4.1	3.9	3.9
Light-Duty Trucks	11.5		20.1		25.8	26.8	27.3	26.9	26.7
Medium- and Heavy-Duty	190.5		309.6		360.6	370.1	376.1	356.0	321.8

[66] Biofuel estimates are presented for informational purposes only in the Energy chapter, 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 7). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards" web page: http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm

[67] Includes "light-duty trucks" fueled by gasoline, diesel and LPG.

[68] 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.

Trucks[b]							
Buses	8.0	10.2	10.6	10.8	10.8	10.3	9.3
Rail	35.5	42.1	45.6	47.8	46.6	43.2	36.2
Recreational Boats	2.0	2.7	3.1	3.2	3.3	0.9	3.5
Ships and Other Boats	7.5	14.1	8.1	7.5	8.2	2.2	1.2
International Bunker Fuels [c]	*11.7*	*6.3*	*9.4*	*8.8*	*8.2*	*9.0*	*8.3*
Jet Fuel	**176.2**	**199.8**	**194.2**	**169.5**	**168.7**	**155.1**	**138.8**
Commercial Aircraft	135.4	169.2	161.2	137.1	138.1	122.2	111.4
Military Aircraft	34.4	21.1	18.1	16.4	16.1	16.3	14.1
General Aviation Aircraft	6.4	9.5	14.9	16.0	14.5	16.6	13.3
International Bunker Fuels [c]	*46.4*	*58.8*	*56.7*	*74.6*	*73.8*	*75.5*	*69.4*
Aviation Gasoline	**3.1**	**2.5**	**2.4**	**2.3**	**2.2**	**2.0**	**1.8**
General Aviation Aircraft	3.1	2.5	2.4	2.3	2.2	2.0	1.8
Residual Fuel Oil	**22.6**	**33.3**	**19.3**	**23.0**	**29.0**	**19.9**	**12.0**
Ships and Other Boats[d]	22.6	33.3	19.3	23.0	29.0	19.9	12.0
International Bunker Fuels [c]	*53.7*	*33.3*	*43.6*	*45.0*	*45.6*	*49.2*	*45.4*
Natural Gas	**36.0**	**35.6**	**33.1**	**33.1**	**35.3**	**36.8**	**36.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.4	0.8	0.8	1.0	1.1	1.1
Pipeline	36.0	35.2	32.2	32.3	34.3	35.7	35.2
LPG	**1.4**	**0.7**	**1.7**	**1.7**	**1.4**	**2.4**	**2.5**
Light-Duty Trucks	0.6	0.5	1.3	1.2	1.0	1.8	1.8
Medium- and Heavy-Duty Trucks[b]	0.8	0.3	0.4	0.5	0.4	0.7	0.7
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**3.4**	**4.7**	**4.5**	**5.0**	**4.7**	**4.4**
Rail	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Total	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Total (Including Bunkers) [c]	**1,600.8**	**1,911.4**	**2,011.1**	**2,011.0**	**2,026.6**	**1,928.3**	**1,847.2**

[a] 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.
[b] Includes medium- and heavy-duty trucks over 8,500 lbs.
[c] 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.
Note: Totals may not sum due to independent rounding.
Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.
+ Less than 0.05 Tg CO_2 Eq.
- Unreported or zero

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; 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.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.[69]

[69] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2009.

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the second largest source of U.S. N_2O emissions (9 percent). From 1990 to 2009, mobile source CH_4 emissions declined by 58 percent, to 2.0 Tg CO_2 Eq. (93 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 46 percent, to 23.9 Tg CO_2 Eq. (77 Gg). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 50 percent decrease in mobile source N_2O emissions from 1998 to 2009 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

Table 3-13: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**4.2**	**2.8**	**1.9**	**1.7**	**1.6**	**1.4**	**1.3**
Passenger Cars	2.6	1.6	1.1	1.0	0.9	0.8	0.7
Light-Duty Trucks	1.4	1.1	0.7	0.6	0.6	0.6	0.6
Medium- and Heavy-Duty Trucks and Buses	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road	**0.4**	**0.5**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**
Ships and Boats	+	+	+	+	+	+	+
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Agricultural Equipment[b]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[c]	+	0.1	0.1	0.1	0.1	0.1	0.1
Other[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**3.4**	**2.5**	**2.3**	**2.2**	**2.0**	**2.0**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "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.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

Table 3-14: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**40.1**	**48.4**	**32.1**	**29.0**	**25.5**	**21.8**	**19.9**
Passenger Cars	25.4	25.2	17.7	15.7	13.7	11.7	10.0
Light-Duty Trucks	14.1	22.4	13.6	12.5	11.1	9.5	9.3
Medium- and Heavy-Duty Trucks and Buses	0.6	0.9	0.8	0.7	0.7	0.6	0.5
Motorcycles	+	+	+	+	+	+	+

Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel On-Road	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.6**	**4.3**	**4.3**	**4.2**	**4.3**	**3.8**	**3.6**
Ships and Boats	0.6	0.9	0.6	0.7	0.8	0.5	0.4
Rail	0.3	0.3	0.4	0.4	0.4	0.3	0.3
Aircraft	1.7	1.9	1.9	1.6	1.6	1.5	1.3
Agricultural Equipment[b]	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment[c]	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Other[d]	0.4	0.5	0.6	0.6	0.6	0.6	0.6
Total	**43.9**	**53.2**	**36.9**	**33.6**	**30.3**	**26.1**	**23.9**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "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.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

CO_2 from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO_2 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). 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 Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2011). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).[70]

   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 4 years). These consumption data sets help inform the annual surveys to arrive at the

[70] 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 emissions of 42 Tg CO_2 Eq. in 2009.

national total and sectoral breakdowns for that total. [71]

It is also important to 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).[72]

2. *Subtract uses accounted for in the Industrial Processes 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 chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2010), Coffeyville (2010), U.S. Census Bureau (2010), EIA (2010c), USGS (1991 through 2010), USGS (1994 through 2010), USGS (1995, 1998, 2000 through 2002, 2007, and 2009), USGS (1991 through 2009a), and USGS (1991 through 2009b).[73]

3. *Adjust for conversion of fuels and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[74] 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.[75] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2011) and data for synthetic natural gas were collected from EIA (2009b), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), and EIA (2007b).

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 the Federal Highway Administration's (FHWA) VMT 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 upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2010), Benson (2002 through 2004), DOE (1993 through 2010), EIA (2009a), EIA (1991 through 2010), EPA (2009), and FHWA (1996 through 2010).[76]

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[71] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[72] 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.

[73] 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 chapter.

[74] Energy statistics from EIA(2010c) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

[75] These adjustments are explained in greater detail in Annex 2.1.

[76] FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.

Fuel use by vehicle class (also in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel

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 (2011).
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).[77] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006 and 2009); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2010) for 1990 through 2001, 2007 and 2008, 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 later 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 CO_2. 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 mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.
8. *Estimate CO_2 Emissions.* Total CO_2 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.
   - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2010); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2010). Fuel use by vehicle class (found in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009.
   - For non-road vehicles, activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), BEA (1991 through 2009), Benson (2002 through 2004), DOE (1993 through 2010),

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was estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[77] See International Bunker Fuels section in this chapter for a more detailed discussion.

DESC (2011), DOC (1991 through 2010), DOT (1991 through 2010), EIA (2009a), EIA (2009d), EIA (2007a), EIA (2002), EIA (1991 through 2011), EPA (2010b), FAA (2008), and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2011). [78] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2010) and USAF (1998). [79]

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 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 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[80] 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 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 Tg CO_2 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 (Tg CO_2 Eq./QBtu)

Sector	1990		2000		2005	2006	2007	2008	2009
Residential [a]	57.4		56.6		56.6	56.5	56.3	56.1	56.0
Commercial [a]	59.2		57.2		57.5	57.2	57.1	56.8	56.9
Industrial [a]	64.3		62.8		64.3	64.5	64.0	63.6	63.2
Transportation [a]	71.1		71.3		71.4	71.6	71.9	71.6	71.5

[78] Data for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model. That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year. Data for inventory years 2006-2009 were developed using AEDT. The AEDT model dynamically models aircraft performance in space and time to produce fuel burn, emissions and noise. Full flight gate-to-gate analyses are possible for study sizes ranging from a single flight at an airport to scenarios at the regional, national, and global levels. AEDT is currently used by the U.S. government to consider the interdependencies between aircraft-related fuel burn, noise and emissions.

[79] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

[80] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

Electricity Generation [b]	87.3		86.2		85.8	85.4	84.7	84.9	83.7
U.S. Territories [c]	73.0		72.5		73.4	73.5	73.8	73.3	73.1
All Sectors [c]	**73.0**		**73.0**		**73.5**	**73.5**	**73.3**	**73.1**	**72.4**

[a] Does not include electricity or renewable energy consumption.
[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-year period of 1990 through 2009, however, 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 2009 was approximately 9 percent below levels in 1990 (see Figure 3-14). 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 CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2010).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

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

[END BOX]

Uncertainty and Time Series Consistency

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 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 CO_2 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 CO_2 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 CO_2 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 for 2009. The amount of CO_2 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 CO_2 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 CO_2 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 Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 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 CO_2 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.[81] 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.[82]

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).[83] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2009 were estimated to be between 5,149.0 and 5,522.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 1 percent below to 6 percent above the 2009 emission estimate of 5,209.0.0 Tg CO_2 Eq.

Table 3-16: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal [b]	**1,841.0**	**1,779.3**	**2,015.6**	**-3%**	**+9%**
Residential	0.6	0.6	0.7	-6%	+15%
Commercial	5.8	5.5	6.7	-5%	+15%
Industrial	83.4	80.5	97.5	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,747.6	1,680.4	1,915.8	-4%	+10%
U.S. Territories	3.5	3.1	4.2	-12%	+19%

[81] 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.

[82] 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.

[83] 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.

Natural Gas [b]	**1,200.9**	**1,209.4**	**1,276.6**	**+1%**	**+6%**
Residential	257.2	250.0	275.2	-3%	+7%
Commercial	167.9	163.2	179.7	-3%	+7%
Industrial	365.0	374.9	412.7	+3%	+13%
Transportation	36.3	35.2	38.8	-3%	+7%
Electricity Generation	373.1	362.3	392.0	-3%	+5%
U.S. Territories	1.5	1.3	1.7	-12%	+17%
Petroleum [b]	**2,166.7**	**2,067.2**	**2,323.5**	**-5%**	**+7%**
Residential	81.4	76.9	85.7	-6%	+5%
Commercial	50.3	47.9	52.4	-5%	+4%
Industrial	282.0	231.2	330.4	-18%	+17%
Transportation	1,683.4	1,598.6	1,826.8	-5%	+9%
Electric Utilities	32.9	31.5	35.4	-4%	+7%
U.S. Territories	36.7	33.8	40.9	-8%	+11%
Total (excluding Geothermal) [b]	**5,208.6**	**5,148.76**	**5,522.0**	**-1%**	**+6%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,209.0**	**5,149.0**	**5,522.4**	**-1%**	**+6%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo 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 CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. 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 CO_2 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 CO_2 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 2011) updated energy consumption statistics across the time series. These revisions primarily impacted the emission estimates for 2007 and 2008. In addition, the coal emissions for U.S. Territories decreased from 2001 to 2008 due to the closure of a coal power plant in the U.S. Virgin Islands. Overall, these changes resulted in an average annual increase of 0.5 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2008.

Planned Improvements

To reduce uncertainty of CO_2 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 CO_2 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.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to

EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Stationary Combustion

Methodology

CH_4 and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2010). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).[84] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[85] Construction and agricultural fuel use was obtained from EPA (2010a). 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.

Emission factors for the four 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.

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

CH_4 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 CH_4 and N_2O 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 Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 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 CO_2 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 N_2O emission factors, based on the SAIC/EIA (2001) report.[86] For these variables, the uncertainty

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[84] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[85] 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.

[86] 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.

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[87] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2009 (including biomass) were estimated to be between 4.1 and 14.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 127 percent above the 2009 emission estimate of 6.2 Tg CO_2 Eq.[88] Stationary combustion N_2O emissions in 2009 (*including* biomass) were estimated to be between 9.8 and 36.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 187 percent above the 2009 emissions estimate of 12.8 Tg CO_2 Eq.

Table 3-17: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Stationary Combustion	CH_4	6.2	4.1	14.0	-34%	+127%
Stationary Combustion	N_2O	12.8	9.8	36.7	-23%	+187%

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

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O 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 2009. 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 CH_4, N_2O, 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

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to a couple of changes, mainly impacting 2007 and 2008 estimates. Slight changes to emission estimates for sectors are due to revised data from EIA (2010). Wood consumption data in EIA (2011) were revised for the residential, commercial, and industrial sectors for 2007 and 2008 as well as for the electric power sector for 2006 through 2008. The combination of the methodological and historical data changes resulted in an average annual increase of 0.01 Tg CO_2 Eq. (0.2 percent) in CH_4 emissions from stationary combustion and an average annual decrease of 0.08 Tg CO_2 Eq. (0.5 percent) in N_2O emissions from stationary combustion for the period 1990 through 2008.

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[87] 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.

[88] 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.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O 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.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O 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 CH_4 and N_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH_4 and N_2O 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)[89] are based on VMT and emission factors by vehicle and fuel type.

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 CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[90]

Emission factors for AFVs were 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

[89] 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.

[90] Additional information regarding the model can be found online at http://www.epa.gov/OMS/m6.htm.

AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2010 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2010).[91] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2010) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2010). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2010a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

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 (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

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 N_2O and CH_4 per kilogram of fuel consumed).[92] Activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DOE (1993 through 2010), DESC (2011), DOT (1991 through 2010), EIA (2008a, 2007a, 2007b, 2002), EIA (2007 through 2010), EIA (1991 through 2011), EPA (2009), Esser (2003 through 2004), FAA (2011, 2010, and 2006), Gaffney (2007), and (2006 through 2010). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2009 estimates of CH_4 and N_2O 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) vehicle miles traveled (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. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Mobile combustion CH_4 emissions from all mobile sources in 2009 were estimated to be between 1.8 and 2.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 15 percent above the corresponding 2009 emission estimate of 2.0 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2009 were estimated to be between 20.5 and 27.9 Tg CO_2 Eq., indicating a range of 14 percent below to 17 percent above the corresponding 2009 emission estimate of 23.9 Tg CO_2 Eq.

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[91] Fuel use by vehicle class (VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline were estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[92] 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: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	2.0	1.8	2.2	-9%	+15%
Mobile Sources	N_2O	23.9	20.5	27.9	-14%	+17%

[a] Range of emission estimates predicted by Monte Carlo 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 Tier 2 approach to 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 CH_4 and N_2O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. 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 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

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. Each year, a number of adjustments are made to the methodologies used in calculating emissions in the current Inventory relative to previous Inventory reports. One of the revisions that were made this year was incorporating motor vehicle age distribution from EPA's MOtor Vehicle Emission Simulator (MOVES) model. MOVES is EPA's tool for estimating emissions from highway vehicles, based on analysis of millions of emission test results and considerable advances in EPA's understanding of vehicle emissions. Population data from the MOVES model was used to estimate the age distribution of motor vehicles in the United States.

Planned Improvements

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

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO_2 emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N_2O and CH_4 emissions factors for non-road equipment.
3. Examine the feasibility of estimating aircraft N_2O and CH_4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N_2O and CH_4

emissions are more dependent on aircraft takeoffs and landings than on total aircraft fuel consumption; however, aircraft emissions are currently estimated from fuel consumption data. FAA's SAGE and AEDT databases contain detailed data on takeoffs and landings for each calendar year starting in 2000, and could potentially be used to conduct a Tier II analysis of aircraft emissions. This methodology will require a detailed analysis of the number of takeoffs and landings by aircraft type on domestic trips, the development of procedures to develop comparable estimates for years prior to 2000, and the dynamic interaction of ambient air with aircraft exhausts is developed. The feasibility of this approach will be explored.

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 will be investigated. 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. As MOVES goes through additional testing and refinement, 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).

CO_2 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 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 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 CO_2 emissions accounted for in the Industrial Processes 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 make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2009 from the non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2009, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,451.0 TBtu, an increase of 0.2 percent since 1990 (see Table 3-20). About 49.9 Tg of the C (182.8 Tg CO_2 Eq.) in these fuels was stored, while the remaining 33.6 Tg C (123.4 Tg CO_2 Eq.) was emitted.

Table 3-19: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	1990		2000		2005	2006	2007	2008	2009
Potential Emissions	310.8		383.6		381.6	381.7	370.1	344.9	306.1
C Stored	192.2		238.6		238.3	236.1	232.8	204.0	182.8
Emissions as a % of Potential	38%		38%		38%	38%	37%	41%	40%
Emissions	**118.6**		**144.9**		**143.4**	**145.6**	**137.2**	**141.0**	**123.4**

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 (2011) (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 chapter.[93] 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 this 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/UNEP/OECD/IEA (1997), 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		2000		2005	2006	2007	2008	2009
Industry	**4,181.1**		**5,214.4**		**5,174.4**	**5,163.2**	**5,060.7**	**4,671.9**	**4,267.7**
Industrial Coking Coal	+		53.0		79.8	62.3	1.7	28.4	6.1
Industrial Other Coal	8.2		12.4		11.9	12.4	12.4	12.4	12.4
Natural Gas to Chemical Plants	277.3		420.3		397.0	407.7	412.5	395.2	366.0
Asphalt & Road Oil	1,170.2		1,275.7		1,323.2	1,261.2	1,197.0	1,012.0	873.1
LPG	1,119.2		1,607.0		1,444.0	1,488.6	1,483.0	1,409.6	1,446.2
Lubricants	186.3		189.9		160.2	156.1	161.2	149.6	134.5
Pentanes Plus	77.5		229.3		146.3	105.5	132.7	114.9	93.4
Naphtha (<401 ° F)	325.9		593.7		679.6	618.1	542.6	467.3	450.7
Other Oil (>401 ° F)	661.4		527.0		514.8	573.4	669.2	599.2	392.5
Still Gas	21.3		12.6		67.7	57.2	44.2	47.3	133.9
Petroleum Coke	54.8		35.3		128.8	172.2	155.9	174.4	133.0
Special Naphtha	100.8		94.4		60.9	68.9	75.5	83.2	44.2
Distillate Fuel Oil	7.0		11.7		16.0	17.5	17.5	17.5	17.5
Waxes	33.3		33.1		31.4	26.1	21.9	19.1	12.2
Miscellaneous Products	137.8		119.2		112.8	136.0	133.5	142.0	151.8
Transportation	**176.0**		**179.4**		**151.3**	**147.4**	**152.2**	**141.3**	**127.1**
Lubricants	176.0		179.4		151.3	147.4	152.2	141.3	127.1
U.S. Territories	**86.7**		**152.2**		**121.9**	**133.4**	**108.4**	**126.7**	**56.3**
Lubricants	0.7		3.1		4.6	6.2	5.9	2.7	1.0

93 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.

Other Petroleum (Misc. Prod.)	86.0		149.1		117.3	127.2	102.5	124.1	55.2
Total	**4,443.8**		**5,546.0**		**5,447.6**	**5,444.0**	**5,321.3**	**4,940.0**	**4,451.0**

+ Does not exceed 0.05 TBtu
Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.
Note: Totals may not sum due to independent rounding.

Table 3-21: 2009 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2 Eq.)
Industry	**4,267.7**	**-**	**79.8**	**-**	**49.5**	**30.3**	**111.1**
Industrial Coking Coal	6.1	31.00	0.2	0.10	0.0	0.2	0.6
Industrial Other Coal	12.4	25.82	0.3	0.58	0.2	0.1	0.5
Natural Gas to Chemical Plants	366.0	14.47	5.3	0.58	3.1	2.2	8.1
Asphalt & Road Oil	873.1	20.55	17.9	1.00	17.9	0.1	0.3
LPG	1,446.2	17.06	24.7	0.58	14.3	10.3	37.9
Lubricants	134.5	20.20	2.7	0.09	0.2	2.5	9.0
Pentanes Plus	93.4	19.10	1.8	0.58	1.0	0.7	2.7
Naphtha (<401° F)	450.7	18.55	8.4	0.58	4.9	3.5	12.9
Other Oil (>401° F)	392.5	20.17	7.9	0.58	4.6	3.3	12.2
Still Gas	133.9	17.51	2.3	0.58	1.4	1.0	3.6
Petroleum Coke	133.0	27.85	3.7	0.30	1.1	2.6	9.5
Special Naphtha	44.2	19.74	0.9	0.58	0.5	0.4	1.3
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	12.2	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	151.8	20.31	3.1	0.00	0.0	3.1	11.3
Transportation	**127.1**	**-**	**2.6**	**-**	**0.2**	**2.3**	**8.5**
Lubricants	127.1	20.20	2.6	0.09	0.2	2.3	8.5
U.S. Territories	**56.3**	**-**	**1.1**	**-**	**0.1**	**1.0**	**3.7**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	**4,451.0**	**-**	**83.5**	**-**	**49.9**	**33.6**	**123.4**

+ Does not exceed 0.05 Tg
- Not applicable.
[a] To 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 2010), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2007a), and pesticide sales and use estimates

(EPA 1998, 1999, 2002, 2004); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2009); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2011); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2009a,b); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2010); and the American Chemistry Council (ACC 2003-2010). 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 Tier 2 methodology (Monte Carlo 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 3-22 and Table 3-23), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, 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 Tier 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 2009 was estimated to be between 97.6 and 135.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 10 percent above the 2009 emission estimate of 123.4 Tg CO_2 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: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Feedstocks	CO_2	79.3	63.4	96.1	-20%	21%
Asphalt	CO_2	0.3	0.1	0.6	-58%	119%
Lubricants	CO_2	17.7	14.6	20.5	-17%	16%
Waxes	CO_2	0.4	0.3	0.7	-29%	74%
Other	CO_2	25.7	10.3	27.0	-60%	5%
Total	**CO_2**	123.4	97.6	135.3	-21%	10%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

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

Source	Gas	2009 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	58%	56%	60%	-3%	4%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO_2	9%	4%	17%	-57%	91%
Waxes	CO_2	58%	49%	71%	-15%	22%
Other	CO_2	17%	16%	66%	-3%	292%

[a] Range of emission estimates predicted by Monte Carlo 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 2009. 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 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 2009 as well as their trends across the time series.

Recalculations Discussion

In previous Inventories, the storage factor for asphalt was incorrectly assumed to be 100 percent. For the current Inventory, it has been updated to 99.6 percent to reflect some loss of VOCs (see Annex 2.3 for more detailed discussion).

Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 were released in the past year. MECS data are only released once every four years and contribute to approximately 28 percent (as a time-weighted average) of the C accounted for in feedstocks. MECS data are used to estimate the amount of C emitted from energy recovery. Updating the energy recovery emission estimates with this new data affected emissions from 2003 through 2009, resulting in annual average increases of 7 percent from 2003 through 2009. In addition, the entire energy recovery time series was recalculated to adjust for energy recovered from combustion of scrap tires. Carbon emissions from scrap tires were inadvertently included in the energy recovery estimates; however, they are already accounted for in the Incineration of Waste category.[94] MECS data were adjusted to remove C from scrap tires used as fuel in cement kilns, lime kilns, and electric arc furnaces. This adjustment resulted in decreases in emissions across the entire time series. Emissions decreased by 0.3, 2.1, 1.3, and 1.5 percent for MECS-reporting years 1991, 1994, 1998, and 2002, respectively. Updating the energy recovery emission estimates with the 2006 MECS data combined with adjusting for combustion of scrap tires increased the 2006 emission estimate by 9.5 percent. Overall, emissions from energy recovery averaged over the entire time series increased by 1.2 percent when compared to last year's inventory estimate because the increase resulting from updating the MECS data more than offsets the decrease from adjusting for scrap tire combustion across the time series.

Planned Improvements

There are several improvements planned for the future:

- 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). EPA plans to better understand these trends to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- More accurate accounting of C in petrochemical feedstocks. 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. EPA plans to research this discrepancy by assessing the trends on both sides of the C balance. An initial review of EIA (2011) data indicates that trends in LPG consumption for non-energy uses may largely contribute to this discrepancy.
- More accurate accounting of C in imports and exports. As part of its effort to address the C balance discrepancy, EPA will examine its import/export adjustment methodology to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for.
- EPA recently researched updating the average carbon content of solvents, 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 carbon in solvents. EPA plans to identify additional sources of solvents data in order to update the C content assumptions.

Finally, 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 and 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 conducting analyses of C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.

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

[94] From a regulatory-definition perspective combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is not considered "incineration;" however the use of the term "incineration" in this document also applies to the combustion of scrap tires and other materials for energy recovery.

and Matdes 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 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, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 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—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, tires (which contain 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 carbon mass balance for non-energy uses of fossil fuels.

Approximately 26 million metric tons of MSW was incinerated in the United States in 2009 (EPA 2011). CO_2 emissions from incineration of waste rose 54 percent since 1990, to an estimated 12.3 Tg CO_2 Eq. (12,300 Gg) in 2009, as the volume of 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 N_2O and CH_4 emissions (De Soete 1993; IPCC 2006). N_2O emissions from the incineration of waste were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2009, and have not changed significantly since 1990. CH_4 emissions from the incineration of waste were estimated to be less than 0.05 Tg CO_2 Eq. (less than 0.5 Gg CH_4) in 2009, and have not changed significantly since 1990.

Table 3-24: CO_2 and N_2O Emissions from the Incineration of Waste (Tg CO_2 Eq.)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.0**	**11.1**	**12.5**	**12.5**	**12.7**	**12.2**	**12.3**
Plastics	5.6	6.1	6.9	6.7	6.7	6.1	6.2
Synthetic Rubber in Tires	0.3	1.5	1.6	1.7	1.8	1.8	1.8
Carbon Black in Tires	0.4	1.8	2.0	2.1	2.3	2.3	2.3
Synthetic Rubber in MSW	0.9	0.7	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.0	1.2	1.2	1.2	1.2	1.2
N_2O	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
CH_4	+	+	+	+	+	+	+
Total	**8.5**	**11.5**	**12.9**	**12.9**	**13.1**	**12.5**	**12.7**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-25: CO_2 and N_2O Emissions from the Incineration of Waste (Gg)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**7,989**	**11,112**	**12,450**	**12,531**	**12,700**	**12,169**	**12,300**
Plastics	5,588	6,104	6,919	6,722	6,660	6,148	6,233
Synthetic Rubber in Tires	308	1,454	1,599	1,712	1,823	1,823	1,823
Carbon Black in Tires	385	1,818	1,958	2,113	2,268	2,268	2,268
Synthetic Rubber in MSW	872	689	781	775	791	770	782
Synthetic Fibers	838	1,046	1,194	1,208	1,159	1,161	1,195
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in 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, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 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, 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 1999 through 2003, 2005 through 2011) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2009 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Markets in the United States, 2007 Edition (RMA 2009a). For 2008 and 2009, synthetic rubber mass in tires is assumed to be equal to that in 2007 due to a lack of more recently available data.

Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: carbon content for 1990 through 1998 is based on the 1998 value; content for 1999 through 2001 is the average of 1998 and 2002 values; and 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 2009b).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO_2 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 N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N_2O and CH_4 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 on total waste incinerated was not available for 2009, so this value was assumed to equal the most recent value available (2008). Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

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

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0
2000	252,328,354	25,974,978	10.3
2005	259,559,787	25,973,520	10.0
2006	267,526,493	25,853,401	9.7
2007	268,279,240	24,788,539	9.2
2008	268,541,088	23,674,017	8.8
2009	268,541,088[a]	23,674,017 [a]	8.8[a]

[a] Assumed equal to 2008 value.
Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Tier 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 N_2O 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 Tier 2 quantitative uncertainty analysis are summarized inTable 3-27. Waste incineration CO_2 emissions in 2009 were estimated to be between 9.8 and 15.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2009 emission estimate of 12.3 Tg CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2009 were estimated to be between 0.2 and 1.5 Tg CO_2 Eq. This indicates a range of 51 percent below to 320 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	12.3	9.8	15.2	-21%	+24%
Incineration of Waste	N_2O	0.4	0.2	1.5	-51%	+320%

[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 2009. 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 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

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. Formerly, the percentage of overall rubber waste that is synthetic (i.e., fossil-derived rather than biogenic) varied across the product categories, ranging from 25 percent for clothing and footwear to 100 percent synthetic rubber for durable goods and containers and packaging. For the current Inventory, this variable was updated to be 70 percent synthetic rubber for all four waste categories based on an industry average (RMA, 2011). This change resulted in an average 1 percent decrease in CO_2 emissions throughout the time series. In addition, the percentage of waste incinerated was updated for 2008 based on data obtained from The State of Garbage in America report (van Haaren et al., 2010). Because the report is released every other year, the percentage incinerated in 2007 was also updated using linear interpolation from the 2006 and 2008 values. The change in the percentage incinerated, along with the change in the percentage synthetic rubber noted above, decreased the 2007 and 2008 estimates by 4 percent and 7 percent, respectively, relative to the previous report.

Planned Improvements

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

Additional data sources for calculating the N_2O and CH_4 emission factors for U.S. incineration of waste may be investigated.

3.4. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. In 2009, 135 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 23 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2009, 14 coal mines collected CH_4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 13 coal mines sold CH_4 to the natural gas pipeline and one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH_4 to fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2009 were estimated to be 71.0 Tg CO_2 Eq. (3,382 Gg), a decline of 16 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions have generally increased.

Table 3-28: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009
UG Mining	62.3		39.4		35.0	35.7	35.7	44.4	50.4
Liberated	67.9		54.4		50.2	54.3	51.0	60.5	67.0
Recovered & Used	(5.6)		(14.9)		(15.1)	(18.7)	(15.3)	(16.1)	(16.5)
Surface Mining	12.0		12.3		13.3	14.0	13.8	14.3	12.9
Post-Mining (UG)	7.7		6.7		6.4	6.3	6.1	6.1	5.6
Post-Mining (Surface)	2.0		2.0		2.2	2.3	2.2	2.3	2.1
Total	**84.1**		**60.4**		**56.9**	**58.2**	**57.9**	**67.1**	**71.0**

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

Table 3-29: CH_4 Emissions from Coal Mining (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
UG Mining	2,968		1,878		1,668	1,699	1,700	2,113	2,401
Liberated	3,234		2,588		2,389	2,588	2,427	2,881	3,189
Recovered & Used	(265.9)		(710.4)		(720.8)	(889.4)	(727.2)	(768.0)	(787.1)
Surface Mining	573.6		585.7		633.1	668.0	658.9	680.5	614.2
Post-Mining (UG)	368.3		318.1		305.9	298.5	289.6	292.0	266.7
Post-Mining (Surface)	93.2		95.2		102.9	108.5	107.1	110.6	99.8
Total	**4,003**		**2,877**		**2,710**	**2,774**	**2,756**	**3,196**	**3,382**

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

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[95] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2009, 13 active coal mines sold recovered CH_4 into the local gas pipeline networks and one coal mine used recovered CH_4 on site for heating. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery

[95] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2010), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average in situ CH_4 content of the coal. Revised data on in situ CH_4 content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average in situ CH_4 content of coals mined in the basin.

Table 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2000	338,168	635,581	973,749
2005	334,398	691,448	1,025,846
2006	325,697	728,447	1,054,144
2007	319,139	720,023	1,039,162
2008	323,932	737,832	1,061,764
2009	301,241	671,475	972,716

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also 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 currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise 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 Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2009 were estimated to be between 62.0 and 82.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.7 percent below to 16.1 percent above the 2009 emission estimate of 71.0 Tg CO_2 Eq.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	71.0	62.0	82.4	-12.7%	+16.1%

[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 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, there were some changes to pre-2009 emission estimates relative to the previous Inventory. For the current Inventory, the conversion factor for converting short tons to metric tons was updated to 0.90718474 to be consistent with the number of significant digits used in other source categories. In the past, 0.9072 had been used. The factor was updated for all years, thus coal production estimates in Table 3-31 have changed slightly.

Other changes include the recalculation of emissions avoided for two Jim Walter Resources (JWR) mines: Blue Creek #4 Mine and Blue Creek #7 Mine. This resulted in changes to emissions avoided numbers for 2007 and 2008.

In 1998, 2000, 2001, 2002, 2003, and 2004, the emissions avoided for the Blacksville No. 2 mine in West Virginia were assigned to Pennsylvania rather than West Virginia. These emissions avoided were correctly assigned to West Virginia in the current Inventory; however, total emissions were not affected.

The emissions avoided for the Emerald and Cumberland mines were adjusted going back to 2006 based on information provided by the project developer.

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

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 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 CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 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 CH_4 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.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2009, varying, in general, by less than 1 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 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 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. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2009, with only ten closures in 2009. By 2009, gross abandoned mine emissions decreased slightly to 8.5 Tg CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 38 mines, resulting in net emissions in 2009 of 5.5 Tg CO_2 Eq.

Table 3-32: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009
Abandoned Underground Mines	6.0		8.9		7.0	7.6	8.9	9.0	8.5
Recovered & Used	0.0		1.5		1.5	2.2	3.3	3.2	3.0
Total	**6.0**		**7.4**		**5.5**	**5.5**	**5.6**	**5.9**	**5.5**

Note: Totals may not sum due to independent rounding.

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
Abandoned Underground Mines	288		422		334	364	425	430	406
Recovered & Used	0		72		70	103	158	150	144
Total	**288**		**350**		**264**	**261**	**267**	**279**	**262**

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 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 CH_4 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 CH_4 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 CH_4 emissions over time for a given 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 CH_4 leaves the system, the reservoir pressure, Pr, declines as described by the isotherm. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). 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 rate at time t in mmcf/d
- q_i = Initial gas rate at time zero (t_o) in million cubic feet per day mmcfd)
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission 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 no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding 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 2003).

$$q = q_{ie}^{\ (-Dt)}$$

where,

- q = Gas flow rate at time t in mcf/d
- q_i = Initial gas flow rate at time zero (t_o) in mcfd

D = Decline rate, 1/yr
t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 − (initial emissions from sealed mine / 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 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 469 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 273 of the 469 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 CH_4 flow to the atmosphere). The remaining 42 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Table 3-34: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	25	25	48	98	127	224
Illinois	30	3	14	47	25	72
Northern Appl.	42	22	16	80	35	115
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**124**	**53**	**96**	**273**	**196**	**469**

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

During the 1970s, 78 percent of CH_4 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 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 CH_4 emission rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd 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. 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. CH_4 degasification amounts were added to the quantity of CH_4 ventilated for the total CH_4 liberation rate for 21 mines that closed between 1992 and 2009. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 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 2009, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 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) CH_4 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 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 Tier 2 quantitative uncertainty analysis are summarized in Table 3-35. Abandoned coal mines CH_4 emissions in 2009 were estimated to be between 4.0 and 7.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 32 percent above the 2009 emission estimate of 5.5 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 42 percent of the mines), with a ±57 percent uncertainty.

Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	5.5	4.0	7.3	-27%	+32%

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

Recalculations Discussion

Changes in pre-2009 emissions avoided relative to the previous Inventory are due to the additions of pre-1972 Grayson Hills Energy and DTE Corinth projects, which were added to the current inventory. There were also two abandoned mines added to the current Inventory, one abandoned in 2007 and one in 2008, which resulted in changes in the liberated emissions relative to the previous report.

3.6. 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 221.2 Tg CO_2 Eq. (10,535 Gg) of CH_4 in 2009, a 17 percent increase over 1990 emissions (see Table 3-36 and Table 3-37), and 32.2 Tg CO_2 Eq. (32,171 Gg) of non-combustion CO_2 in 2009, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

CH_4 and non-combustion CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, 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 CH_4 and non-combustion CO_2 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Emissions from pneumatic devices, well clean-ups, and gas well completions and re-completions with hydraulic fracturing account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from field production accounted for approximately 59 percent of CH_4 emissions and about 34 percent of non-combustion CO_2 emissions from natural gas systems in 2009.

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 CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 8 percent of CH_4 emissions and approximately 66 percent of non-combustion CO_2 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 20 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,208,000 miles of distribution mains in 2009, an increase from just over 944,000 miles in 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 percent of CH_4 emissions from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2009 were 13 percent lower than 1990 levels.

Table 3-36: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990		2000		2005	2006	2007	2008	2009
Field Production	89.2		113.5		105.4	134.0	118.2	122.9	130.3
Processing	18.0		17.7		14.3	14.5	15.1	15.7	17.5
Transmission and Storage	49.2		46.7		41.4	41.0	42.5	43.3	44.4
Distribution	33.4		31.4		29.3	28.3	29.4	29.9	29.0
Total	**189.8**		**209.3**		**190.4**	**217.7**	**205.2**	**211.8**	**221.2**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-37: CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990		2000		2005	2006	2007	2008	2009
Field Production	4,248		5,406		5,021	6,380	5,628	5,854	6,205
Processing	855		841		681	689	717	748	834
Transmission and Storage	2,344		2,224		1,973	1,950	2,025	2,062	2,115

Distribution	1,591		1,497		1,395	1,346	1,402	1,423	1,381
Total	**9,038**		**9,968**		**9,069**	**10,364**	**9,771**	**10,087**	**10,535**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-38: Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990		2000		2005	2006	2007	2008	2009
Field Production	9.7		6.4		8.0	9.4	9.7	11.3	10.9
Processing	27.8		23.3		21.7	21.2	21.2	21.4	21.2
Transmission and Storage	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Distribution	+		+		+	+	+	+	+
Total	**37.6**		**29.9**		**29.9**	**30.8**	**31.1**	**32.8**	**32.2**

Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 Tg CO_2 Eq.

Table 3-39: Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	1990		2000		2005	2006	2007	2008	2009
Field Production	9,704		6,425		8,050	9,438	9,746	11,336	10,877
Processing	27,763		23,343		21,746	21,214	21,199	21,385	21,189
Transmission and Storage	62		64		64	63	64	65	65
Distribution	46		44		41	40	41	42	41
Total	**37,574**		**29,877**		**29,902**	**30,755**	**31,050**	**32,828**	**32,171**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and non-combustion CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-combustion CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These 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.

Although the inventory primarily uses EPA/GRI emission factors, significant improvements were made to the emissions estimates for three sources this year: gas well cleanups, condensate storage tanks and centrifugal compressors. In addition, data for two sources not included in the EPA/GRI study – gas well completions and gas well workovers (re-completions) with hydraulic fracturing- was added this year. In the case of gas well cleanups, the methodology was revised to use a large sample of well and reservoir characteristics from the HPDI database (HPDI 2009) along with an engineering statics equation (EPA 2006a) to estimate the volume of natural gas necessary to expel a liquid column choking the well production. The same sample E&P Tank sample runs for condensate tank flashing emissions was used; however, the factor was improved by using a large sample distribution of condensate production by gravity from the HPDI database (HPDI 2009) to weigh the sample simulation flashing emissions rather than assuming a uniform distribution of condensate gravities. Additionally, TERC (TERC 2009) data representing two regions was used in the emission factors for those two regions to estimate the effects of separator dump valves malfunctioning and allowing natural gas to vent through the downstream storage tanks. The EPA/GRI emission factor for centrifugal compressors sampled emissions at the seal face of wet seal compressors. A World Gas Conference publication (WGC 2009) on the seal oil degassing vents was used to update this factor and to also account for the emergence of dry seal centrifugal compressors (EPA 2006b), which eliminates seal oil degassing vents and reduces overall emissions. Gas well completions and workovers with hydraulic fracturing were not common at the time the EPA/GRI survey was conducted. Since then, emissions data has become available through Natural Gas STAR experiences and presentations (EPA 2004, 2007) as these activities became more prevalent. The EPA/GRI study and previous Inventories did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring. The changes for gas well cleanups, condensate storage tanks, centrifugal compressors, and gas well completions and gas well workovers (re-completions) with hydraulic fracturing are described below in the Recalculations section. See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors and adjust CH_4 emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the methane composition for each NEMS oil and gas supply module region. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this 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 @RISK model utilizes 1992 (base year) emissions to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2009.

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 2009. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH_4 emissions in 2009 were estimated to be between 179.1 and 287.6 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2009 were estimated to be between 26.1 and 41.9 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[c]	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]

Natural Gas Systems	CH_4	221.2	179.1	287.6	-19%	+30%
Natural Gas Systems[b]	CO_2	32.2	26.1	41.9	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.
[c] 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

A number of potential data sources were investigated to improve selected emission factors in the natural gas industry. First, the HPDI database for well production and well properties was investigated for potential engineering parameters to be used in engineering equations to develop a new emission factor for well cleanups (HPDI 2009). The database was queried to obtain average well depth, shut-in pressure, well counts, and well production from each basin. These parameters were used along with industry experiences to develop an engineering estimate of emissions from each well in each basin of the sample data. The analysis led to a new emission factor for the gas well cleanup source.

Additionally, industry experiences with hydraulic fracturing of tight formations for the completion or workover of natural gas wells were reviewed to account for this source of emissions. Several Partners of the Natural Gas STAR Program have reported recovering substantial volumes of natural gas that would have otherwise been vented following completions or re-completions (workovers) involving hydraulic fracturing. This completion method, which is a large emission source, was not characterized by the base EPA/GRI 1996 study and has not been accounted for in the national Inventory until this year.

A World Gas Conference paper (WGC 2009) gathered 48 sample measurements of centrifugal compressor wet seal oil degassing emissions and published the results. The base year EPA/GRI 1996 study did not measure emissions from the seal oil degassing vent. Instead seal face emissions were quantified and as such this emission source has gone uncharacterized in the national Inventory until this year.

In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. These data were included where available for the Inventory. More data will be necessary to potentially separate this source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

A number of other data sources for fugitive emission factors from the processing and transmission and storage segments were reviewed. Several studies have been published since the EPA/GRI 1996 base year study that sample emissions from the same common equipment components. The raw emissions data from these surveys can potentially be combined with the raw data from the base year study to develop stronger emission factors. In addition to common component leaks, several of these studies propose emission factors for pneumatic devices or other sources. These studies require further review and thus the data are not included in the Inventory at this time.

Recalculations Discussion

Methodologies for gas well cleanups and condensate storage tanks were revised for the current Inventory, and new sources of data for centrifugal compressors with wet seals, gas well completions with hydraulic fracturing, and gas well workovers with hydraulic fracturing were used.

The largest increase in emissions relative to the previous Inventory was due to the revised emission factor for gas well cleanups (also referred to in industry as gas well liquids unloading). HPDI well production and well property sample data on well depth, shut-in pressure, and production rates were used in an engineering equation to re-estimate the average unloading emissions by NEMS oil and gas module region for this source (HPDI 2009). This methodological change increased emissions by more than 22 times while decreasing the substantial uncertainty that was associated with the previous emission factor from the EPA/GRI 1996 study. The activity data remained the same as the previous methodology. Emissions from non-Gas STAR Partners were not considered, nor was an independent estimate of the scope of those emissions accounted for. Reductions beyond those reported from Natural

Gas STAR Partners will be considered for inclusion in the next Inventory of sufficient data are available.

The next largest increase in emissions was due to the inclusion of gas well completions and workovers involving hydraulic fracture (i.e. unconventional completions and workovers). The EPA/GRI 1996 study did not account for this emerging technology and the source was previously unaccounted for in the Inventory. The Inventory did account for completion flaring, however, this only includes emissions from completions without hydraulic fracturing (i.e. conventional completions), which the EPA/GRI 1996 study assumes are mostly flared. Unlike completions and workovers without hydraulic fracturing (i.e. conventional workovers), the high pressure venting of gas in order to expel the large volumes of liquid used to fracture the well formation, results in a large emission of natural gas. The Inventory tracks activity data for wells completed with hydraulic fracturing in each region. The gas well completions with hydraulic fracturing was approximated using total number of producing gas wells completed with hydraulic fracturing and the total number of shut-in gas wells completed with hydraulic fracturing from each year. This approximation is made by taking the difference between the number of unconventional wells reported by EIA for the current year and the previous year. Since drilling and hydraulic fracturing in unconventional (e.g. shale, tight, and coal bed methane) formations is a relatively new technology, it is assumed that zero gas wells completed with hydraulic fracturing are shut-in each year. This activity data was used along with a newly developed emission factor to estimate emissions from these sources. It was assumed that approximately 50 percent of emissions from gas well completions and workovers with hydraulic fracturing would be flared due to states such as Wyoming that do not permit the venting of natural gas during well completions.

The same E&P Tank simulation data for hydrocarbon liquids above 45˚API flashing emission in tanks was used as in previous Inventories to estimate emissions from condensate tanks; however, these flashing emissions simulations were coupled with a large sample of condensate production gravities from the HPDI database to improve the factor to account for the average national distribution of condensate gravities. Previously, a simple average of simulation results for each liquid gravity was used. Additionally, the TERC (2009) study provided a small sample of data representing two regions in Texas where separator dump valve malfunctions were detected and measured. This data was applied only to the regions represented by the study to account for this emission source.

Finally, WGC (2009) sample data on centrifugal compressor seal oil degassing vent rates was used to divide the centrifugal compressors source in the processing and transmission and storage segments into two sources—centrifugal compressors equipped with wet seals and centrifugal compressors equipped with dry seals. The seal oil degassing vent (found with compressors using wet seals) was previously unaccounted for in the Inventory. This improved methodology accounted for an increase in emissions from these sources between 50 and 100 percent.

Finally, the previous Inventory activity data are updated with revised values each year. However, the impact of these changes was small compared to the changes described above.

The net effect of these changes was to increase total CH_4 emissions from natural gas systems between 47 and 120 percent each year between 1990 and 2008 relative to the previous report. The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of gas well completions and workovers with hydraulic fracturing.

Planned Improvements

Emission reductions reported to Natural Gas STAR are deducted from the total sector emissions each year in the natural gas systems inventory model to estimate emissions. These reported reductions often rely on Inventory emission factors to quantify the extent of reductions. These reductions are also a source of uncertainty that is not currently analyzed in the Inventory. Emissions reductions—in particular from gas well cleanups—may be underestimated, and we intend to investigate whether additional data are available, and if appropriate, revisions to more accurately account for emissions from natural gas systems will be incorporated into future inventories. Additionally, accounting for the uncertainty of these reductions to more accurately provide upper and lower bounds within the 95 percent confidence interval, will be investigated.

Separately, a larger study is currently underway to update selected compressor emission factors used in the national inventory. Most of the activity factors and emission factors in the natural gas inventory are from the EPA/GRI (1996) study. The current measurement-based study to develop updated emission factors for compressors is intended to better reflect current national circumstances. Results from these studies are expected in 2011, and will be incorporated into the Inventory, pending a peer review.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as it becomes available on this emissions source and emissions will be updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule, Subpart W) will be reviewed for potential improvements to the natural gas systems emissions estimates. The rule will collect actual activity data using improved quantification methods from those used in several of the studies which form the basis of this Inventory. Data collection for Subpart W began January 1, 2011 with emissions reporting beginning in 2012. These base year 2011 data will be reviewed for inclusion into a future Inventory to improve the accuracy and reduce the uncertainty of the emission estimates.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Combusted CO_2 emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH_4 and CO_2 emissions from petroleum systems in 2009 were 30.9 Tg CO_2 Eq. (1,473 Gg CH_4) and 0.5 Tg CO_2 (463 Gg), respectively. Since 1990, CH_4 emissions have declined by 13 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-41and Table 3-42). CO_2 emissions have also declined by 17 percent since 1990 due to similar reasons (see Table 3-43 and Table 3-44).

Production Field Operations. Production field operations account for about 98 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for over 90 percent of the emissions from the production sector, unburned CH_4 combustion emissions account for 6.4 percent, fugitive emissions are 3.4 percent, and process upset emissions are slightly under two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from oil tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining six percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level data on CH_4 emissions in production field operations, refer to Annex 3.5.

Vented CO_2 associated with natural gas emissions from field operations account for 99 percent of the total CO_2 emissions from this source category, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions from this source category, while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 61 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 20 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly less than two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented emissions account for about 86 percent of the emissions, while both fugitive and combustion emissions account for approximately seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Asphalt blowing from crude oil refining accounts for 36 percent of the total non-combustion CO_2 emissions in petroleum systems.

Table 3-41: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009
Production Field Operations	**34.7**		**30.8**		**28.7**	**28.7**	**29.3**	**29.6**	**30.3**
Pneumatic device venting	10.3		9.0		8.4	8.3	8.4	8.7	8.8
Tank venting	5.3		4.5		3.9	3.9	4.0	4.0	4.5
Combustion & process upsets	1.9		1.6		1.5	1.5	1.5	1.6	2.0
Misc. venting & fugitives	16.8		15.3		14.5	14.6	15.0	14.8	14.6
Wellhead fugitives	0.6		0.5		0.4	0.4	0.4	0.5	0.5
Crude Oil Transportation	**0.1**		**0.1**		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**		**0.6**		**0.6**	**0.6**	**0.6**	**0.5**	**0.5**
Total	**35.4**		**31.5**		**29.4**	**29.4**	**30.0**	**30.2**	**30.9**

Note: Totals may not sum due to independent rounding.

Table 3-42: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
Production Field Operations	**1,653**		**1,468**		**1,366**	**1,365**	**1,396**	**1,409**	**1,444**
Pneumatic device venting	489		428		397	396	398	416	419
Tank venting	250		214		187	188	192	189	212
Combustion & process upsets	88		76		71	71	72	75	94
Misc. venting & fugitives	799		727		691	693	714	707	696
Wellhead fugitives	26		22		19	17	20	23	23
Crude Oil Transportation	**7**		**5**		**5**	**5**	**5**	**5**	**5**
Refining	**25**		**28**		**28**	**28**	**27**	**25**	**24**
Total	**1,685**		**1,501**		**1,398**	**1,398**	**1,427**	**1,439**	**1,473**

Note: Totals may not sum due to independent rounding.

Table 3-43: CO_2 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009
Production Field Operations	**0.4**		**0.3**		**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Pneumatic device venting	+		+		+	+	+	+	+
Tank venting	0.3		0.3		0.2	0.2	0.3	0.2	0.3
Misc. venting & fugitives	+		+		+	+	+	+	+
Wellhead fugitives	+		+		+	+	+	+	+
Crude Refining	**0.2**		**0.2**		**0.2**	**0.2**	**0.2**	**0.2**	**0.1**
Total	**0.6**		**0.5**		**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-44: CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
Production Field Operations	**376**		**323**		**285**	**285**	**292**	**288**	**319**
Pneumatic device venting	27		24		22	22	22	23	23
Tank venting	328		281		246	246	252	247	278
Misc. venting & fugitives	18		17		16	16	16	16	16
Wellhead fugitives	1		1		1	1	1	1	1
Crude Refining	**180**		**211**		**205**	**203**	**182**	**165**	**144**
Total	**555**		**534**		**490**	**488**	**474**	**453**	**463**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity factors for the years 1990 through 2009 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, BOEMRE 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2009. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2010a-c). 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 2009).

For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2009 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2010, 1995 through 2010, 1995 through 2010a-b), 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 reports (BOEMRE 2005, 2010a-c), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2010a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2008), and the United States Army Corps of Engineers (1995-2008).

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO_2 are estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed 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.

The detailed, bottom-up Inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Petroleum systems CH_4 emissions in 2009 were estimated to be between 23.5 and 76.9 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.4 and 1.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2009 emission estimates of 30.9 and 0.5 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Petroleum Systems	CH_4	30.9	23.5	76.9	-24%	149%
Petroleum Systems	CO_2	0.5	0.4	1.2	-24%	149%

[a] Range of 2009 relative uncertainty predicted by Monte Carlo 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.
Note: Totals may not sum due to independent rounding

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

As part of QA/QC and verification activities done for the Inventory, potential improvements were identified, which include a new emissions source associated with fixed roof storage tank emissions in the production segment. In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. This data was included where available for the Inventory (see Recalculation discussion below). More data will be necessary to potentially add this as a separate source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

Recalculations Discussion

Most revisions for the current Inventory relative to the previous report were due to updating previous years' data with revised data from existing data sources. Well completion venting, well drilling, and offshore platform activity factors were updated from existing data sources from 1990 onward.

Additionally, the emission factor for venting from fixed roof storage tanks in the crude oil production segment was revised. Using the same E&P Tank sample data runs on crude oil gravities ranging up to 45˚API, a new national level flashing emissions factor was developed by using a large sample of production data, sorted by gravity, available from the HPDI database.

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas (TERC 2009). This data was plotted and compared to the flashing emissions simulated via E&P Tank simulation. EPA observed that additional emissions beyond the flashing were present in approximately 50 percent of the tanks. These emissions may be attributed to separator dump valves malfunctioning or other methods of associated gas entering the tank and venting from the roof. Because the dataset was limited to represent production from only 14 counties that represent 0.5 percent of U.S. production, the national emission factor was scaled up such that only production from these counties is affected by the occurrence of associated gas venting through the storage tank.

Planned Improvements

As noted above, nearly all emission factors used in the development of the petroleum systems estimates were taken from EPA (1995, 1996, 1999), with the remaining emission factors taken from EPA default values (EPA 2005) and a consensus of industry peer review panels. These emission factors will be reviewed as part of future Inventory work. Results of this review and analysis will be incorporated into future inventories, as appropriate.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as they become available on this emissions source and emissions updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program will be reviewed for potential improvements to petroleum systems emissions sources. The rule will collect actual activity data and improved quantification methods from those used in several of the studies which form the basis of this Inventory. This data will be incorporated as appropriate into the current Inventory to improve the accuracy and uncertainty of the emissions estimates. In particular, EPA will investigate whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems inventory (e.g., CO_2 process emissions from hydrogen production).

In 2010, all U.S. petroleum refineries were required to collect information on their greenhouse gas emissions. This data will be reported to EPA through its Greenhouse Gas Reporting Program in 2011. Data collected under this program will be evaluated for use in future inventories to improve the calculation of national emissions from petroleum systems.

[BEGIN BOX]

Box 3-3. 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 CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 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 CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 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 (IPCC, 2006) included, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. 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 CO_2 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 CO_2 emissions estimates for geologic storage.

Beginning in 2010, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground will be required to calculate and report greenhouse gas data annually to EPA through its Greenhouse

Gas Reporting Program. The Greenhouse Gas Reporting Rule requires greenhouse gas reporting from facilities that inject CO_2 underground for geologic sequestration, and requires greenhouse gas reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Beginning in 2010, facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program, which will be reported to EPA in early 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain, EPA intends to evaluate that information closely and consider opportunities for improving our current inventory estimates.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 47.3 Tg CO_2 (47,340 Gg CO_2) (see Table 3-46 and Table 3-47). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted.

Table 3-46: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	1990		2000		2005	2006	2007	2008	2009
Acid Gas Removal Plants	4.8		2.3		5.8	6.2	6.4	6.6	7.0
Naturally Occurring CO_2	20.8		23.2		28.3	30.2	33.1	36.1	39.7
Ammonia Production Plants	+		0.7		0.7	0.7	0.7	0.6	0.6
Pipelines Transporting CO_2	+		+		+	+	+	+	+
Total	**25.6**		**26.1**		**34.7**	**37.1**	**40.1**	**43.3**	**47.3**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note; Totals may not sum due to independent rounding.

Table 3-47: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	1990		2000		2005	2006	2007	2008	2009
Acid Gas Removal Plants	4,832		2,264		5,798	6,224	6,088	6,630	7,035
Naturally Occurring CO_2	20,811		23,208		28,267	30,224	33,086	36,102	39,725
Ammonia Production Plants	+		676		676	676	676	580	580
Pipelines Transporting CO_2	8		8		7	7	7	8	8
Total	**25,643**		**26,149**		**34,742**	**37,124**	**40,141**	**43,311**	**47,340**

+ Does not exceed 0.5 Gg.
Note: Totals do not include emissions from pipelines transporting CO_2
Note; Totals may not sum due to independent rounding.

[END BOX]

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-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2009 are reported in Table 3-48.

Table 3-48: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	1990		2000		2005	2006	2007	2008	2009
NO_x	**21,106**		**18,477**		**15,319**	**14,473**	**13,829**	**13,012**	**10,887**
Mobile Combustion	10,862		10,199		9,012	8,488	7,965	7,441	6,206
Stationary Combustion	10,023		8,053		5,858	5,545	5,432	5,148	4,159
Oil and Gas Activities	139		111		321	319	318	318	393
Incineration of Waste	82		114		129	121	114	106	128
*International Bunker Fuels**	*2,020*		*1,344*		*1,703*	*1,793*	*1,791*	*1,917*	*1,651*
CO	**125,640**		**89,714**		**69,062**	**65,399**	**61,739**	**58,078**	**49,647**
Mobile Combustion	119,360		83,559		62,692	58,972	55,253	51,533	43,355
Stationary Combustion	5,000		4,340		4,649	4,695	4,744	4,792	4,543

Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Oil and Gas Activities	302	146	318	319	320	322	345
*International Bunker Fuels**	*130*	*128*	*132*	*161*	*160*	*165*	*149*
NMVOCs	**12,620**	**8,952**	**7,798**	**7,702**	**7,604**	**7,507**	**5,333**
Mobile Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Stationary Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
*International Bunker Fuels**	*61*	*45*	*54*	*59*	*59*	*62*	*57*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. 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 categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

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 2009. 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.[96] These decisions are reflected in the IPCC methodological guidance, including the 2006 IPCC Guidelines, 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).[97]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[98] Emissions from ground transport activities—by road vehicles and trains—even when crossing

[96] 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).

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

[98] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation

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.[99]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O 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. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2009 from the combustion of international bunker fuels from both aviation and marine activities were 124.4 Tg CO_2 Eq., or ten percent above emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 49 percent and decreased by 18 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-49: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111.8**	**98.5**	**109.7**	**128.4**	**127.6**	**133.7**	**123.1**
Aviation	46.4	58.8	56.7	74.6	73.8	75.5	69.4
Marine	65.4	39.7	53.0	53.8	53.9	58.2	53.7
CH_4	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.1**	**0.9**	**1.0**	**1.2**	**1.2**	**1.2**	**1.1**
Aviation	0.5	0.6	0.6	0.8	0.8	0.8	0.7
Marine	0.5	0.3	0.4	0.4	0.4	0.5	0.4
Total	**113.0**	**99.5**	**110.9**	**129.7**	**129.0**	**135.1**	**124.4**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-50: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111,828**	**98,482**	**109,750**	**128,384**	**127,618**	**133,704**	**123,127**
Aviation	46,399	58,785	56,736	74,552	73,762	75,508	69,404
Marine	65,429	39,697	53,014	53,832	53,856	58,196	53,723
CH_4	**8**	**6**	**7**	**8**	**8**	**8**	**7**
Aviation	2	2	2	2	2	2	2

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).

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

Marine	7		4		5	5	5	6	5
N_2O	**3**		**3**		**3**	**4**	**4**	**4**	**4**
Aviation	2		2		2	2	2	2	2
Marine	2		1		1	1	1	1	1

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

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C 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 3.7 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 (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. 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 aircraft fuel consumption for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model (FAA 2006). That tool has been subsequently replaced by the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for flights globally in a given year (FAA 2010). Data for inventory years 2006 through 2009 were developed using AEDT.

International aviation bunker fuel consumption from 1990 to 2009 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010). 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 by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2011). 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 3-51. See Annex 3.7 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 1991 through 2010) for 1990 through 2001, 2007, through 2009, 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 DESC (2011). The total amount of fuel provided to naval vessels was reduced by 13 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 3-52.

Table 3-51: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**

U.S. and Foreign Carriers	4,934	6,157	5,943	7,809	7,726	7,909	7,270
U.S. Military	862	480	462	400	410	386	368
Total	**5,796**	**6,638**	**6,405**	**8,209**	**8,137**	**8,295**	**7,638**

Note: Totals may not sum due to independent rounding.

Table 3-52: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2000	2005	2006	2007	2008	2009
Residual Fuel Oil	4,781	2,967	3,881	4,004	4,059	4,373	4,040
Distillate Diesel Fuel & Other	617	290	444	446	358	445	426
U.S. Military Naval Fuels	522	329	471	414	444	437	384
Total	**5,920**	**3,586**	**4,796**	**4,864**	**4,861**	**5,254**	**4,850**

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.[100] 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 CO_2 in the Revised 1996 IPCC Guidelines is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

[100] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

near-ground level emissions of gases other than CO_2.[101]

There is also concern as to the reliability of the existing DOC (1991 through 2010) 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 2008. 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 CO_2, CH_4, and N_2O 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.

Recalculations Discussion

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2008 relative to the previous Inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.13 Tg CO_2 Eq. (0.1 percent) in CO_2 emissions, an annual decrease of less than 0.01 Tg CO_2 Eq. (0.05 percent) in CH_4 emissions, and an annual decrease of less than 0.01 Tg CO_2 Eq. (0.1 percent) in N_2O emissions.

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 from corn and woody crops generates CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 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 7), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2009, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 183.8 Tg CO_2 Eq. (183,777 Gg) (see Table 3-53 and Table 3-54). As the largest consumer of woody biomass, the industrial sector was responsible for 62 percent of the CO_2 emissions from this source. Emissions from this sector decreased from 2008 to 2009 due to a corresponding decrease in wood consumption. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-53: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135.3	153.6	136.3	138.2	132.6	126.1	114.2
Residential	59.8	43.3	44.3	40.2	44.3	46.4	44.3

[101] 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.

Commercial	6.8	7.4	7.2	6.7	7.2	7.5	7.4
Electricity Generation	13.3	13.9	19.1	18.7	19.2	18.3	17.8
Total	**215.2**	**218.1**	**206.9**	**203.8**	**203.3**	**198.4**	**183.8**

Note: Totals may not sum due to independent rounding.

Table 3-54: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135,348	153,559	136,269	138,207	132,642	126,145	114,222
Residential	59,808	43,309	44,340	40,215	44,340	46,402	44,340
Commercial	6,779	7,370	7,182	6,675	7,159	7,526	7,406
Electricity Generation	13,252	13,851	19,074	18,748	19,175	18,288	17,809
Total	**215,186**	**218,088**	**206,865**	**203,846**	**203,316**	**198,361**	**183,777**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles.

In 2009, the United States consumed an estimated 894 trillion Btu of ethanol, and as a result, produced approximately 61.2 Tg CO_2 Eq. (61,231 Gg) (see Table 3-55 and Table 3-56) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-55: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	4.1	9.2	22.4	30.3	38.1	53.8	60.2
Industrial	0.1	0.1	0.5	0.7	0.7	0.8	0.9
Commercial	+	+	0.1	0.1	0.1	0.1	0.2
Total	**4.2**	**9.4**	**23.0**	**31.0**	**38.9**	**54.8**	**61.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-56: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation[a]	4,139	9,239	22,427	30,255	38,138	53,827	60,176
Industrial	56	87	469	662	674	798	892
Commercial	34	26	60	86	135	146	163
Total	**4,229**	**9,352**	**22,956**	**31,002**	**38,946**	**54,770**	**61,231**

[a] See Annex 3.2, Table A-88 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2010) (see Table 3-57), 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 CO_2 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 CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2010) (see Table 3-58).

Table 3-57: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	1,442	1,636	1,452	1,472	1,413	1,344	1,217

Residential	580		420		430	390	430	450	430
Commercial	66		71		70	65	69	73	72
Electricity Generation	129		134		185	182	186	177	173
Total	**2,216**		**2,262**		**2,136**	**2,109**	**2,098**	**2,044**	**1,891**

Table 3-58: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990		2000		2005	2006	2007	2008	2009
Transportation	60.5		135.0		327.6	442.0	557.1	786.3	879.0
Industrial	0.8		1.3		6.8	9.7	9.8	11.7	13.0
Commercial	0.5		0.4		0.9	1.3	2.0	2.1	2.4
Total	**61.8**		**136.6**		**335.3**	**452.9**	**568.9**	**800.1**	**894.5**

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 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values were revised for 2006 through 2008 based on updated information from EIA's Annual Energy Review (EIA 2010). This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of 0.8 Tg CO_2 Eq. (0.4 percent) from 1990 through 2008. The C content coefficient for ethanol was also revised to be consistent with the carbon content coefficients used for EPA's Mandatory Greenhouse Gas Reporting Rule. Slight adjustments were made to ethanol consumption based on updated information from EIA (2010), which slightly decreased estimates for ethanol consumed. As a result of these adjustments, average annual emissions from ethanol consumption increased by about 0.3 Tg CO_2 Eq. (1.9 percent) relative to the previous Inventory.

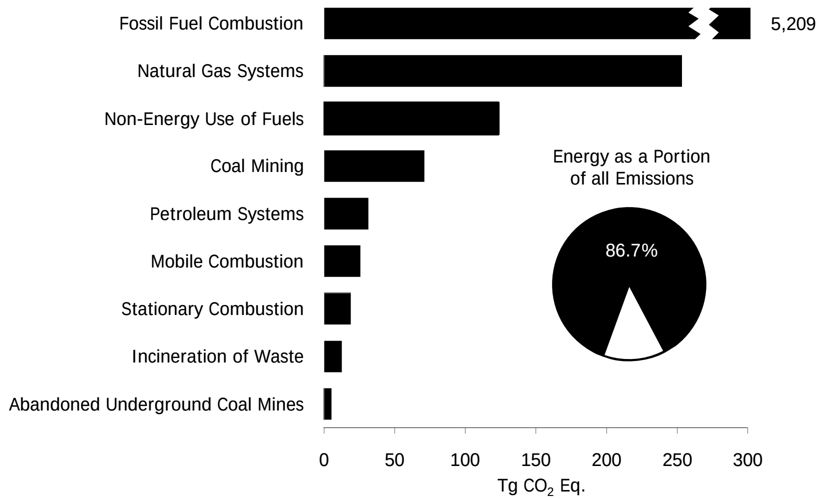


Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

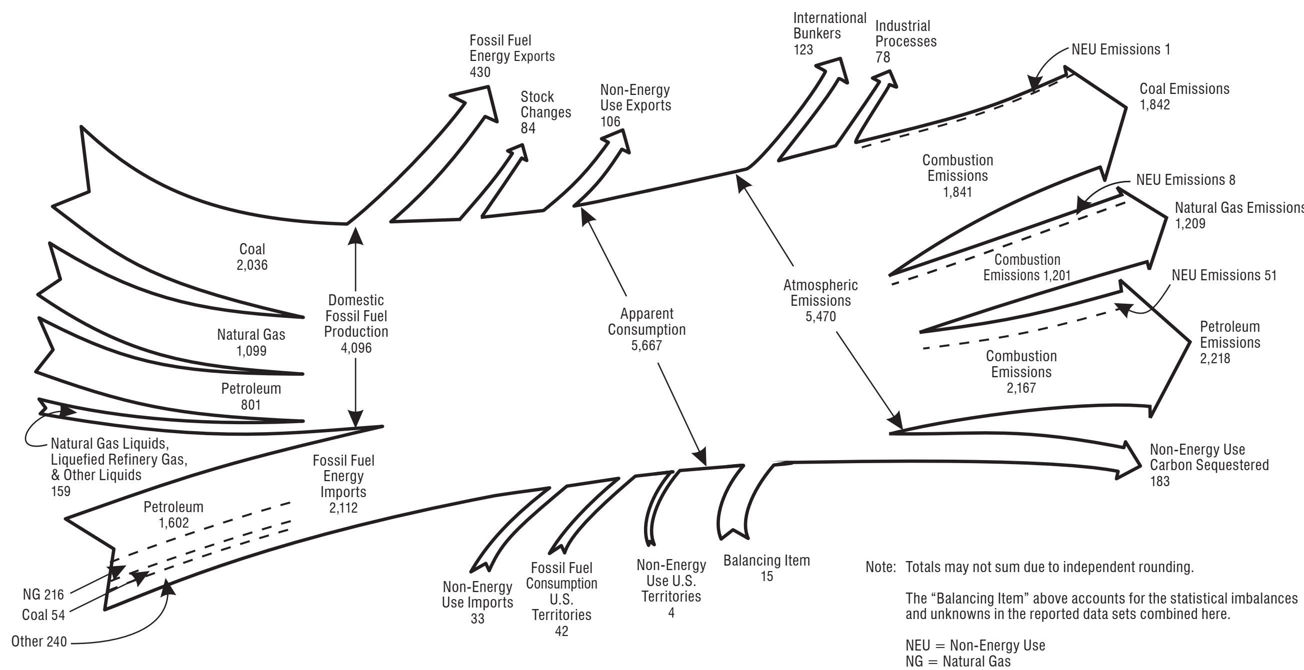


Figure 3-2 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

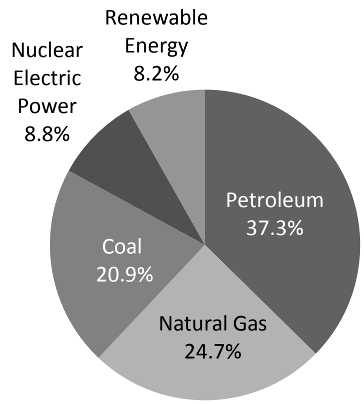


Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

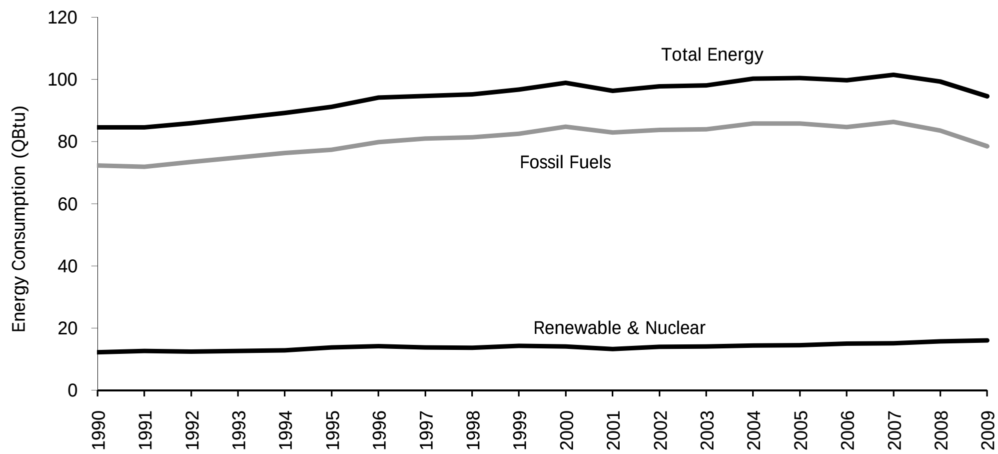


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)
Note: Expressed as gross calorific values.

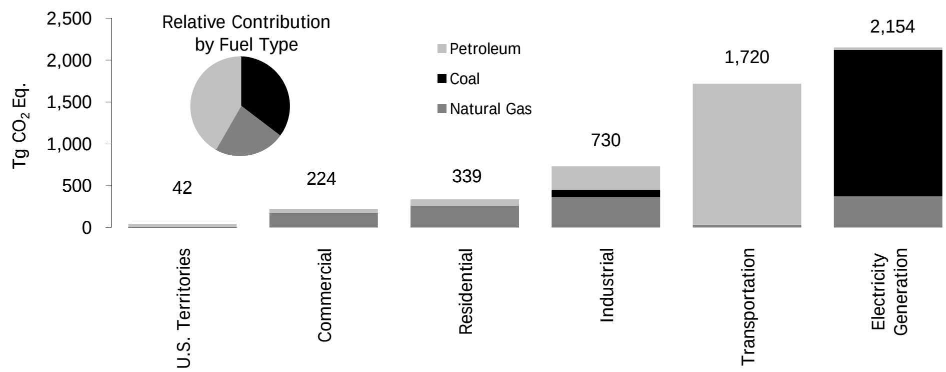


Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type
Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

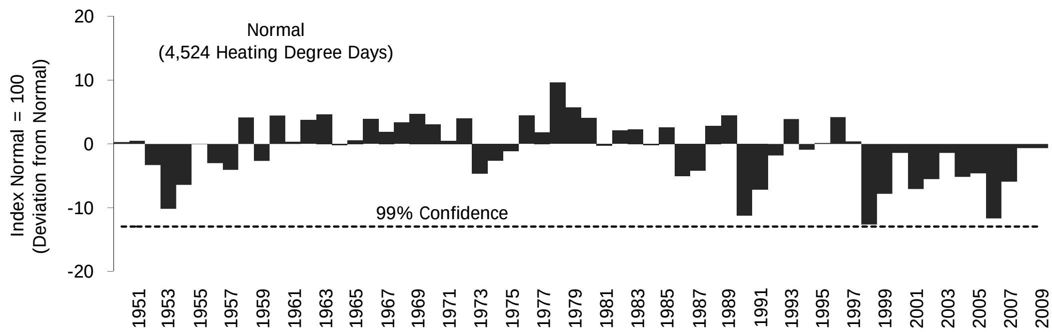


Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

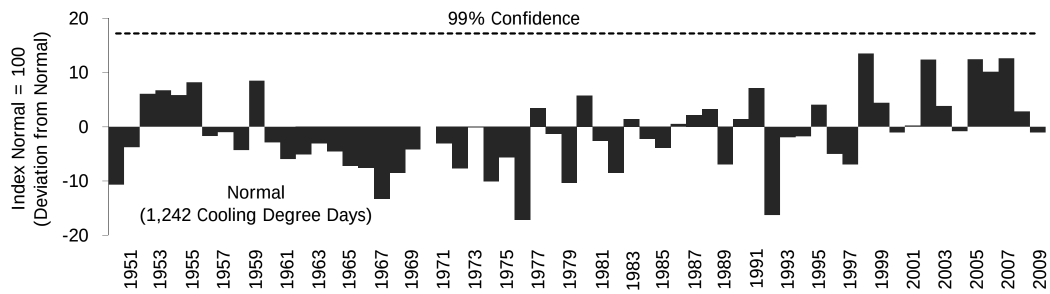


Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

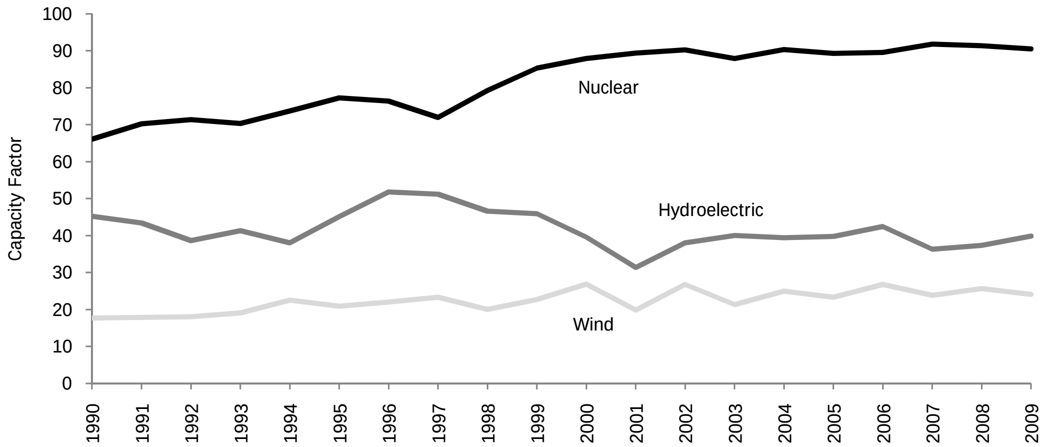


Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2009)

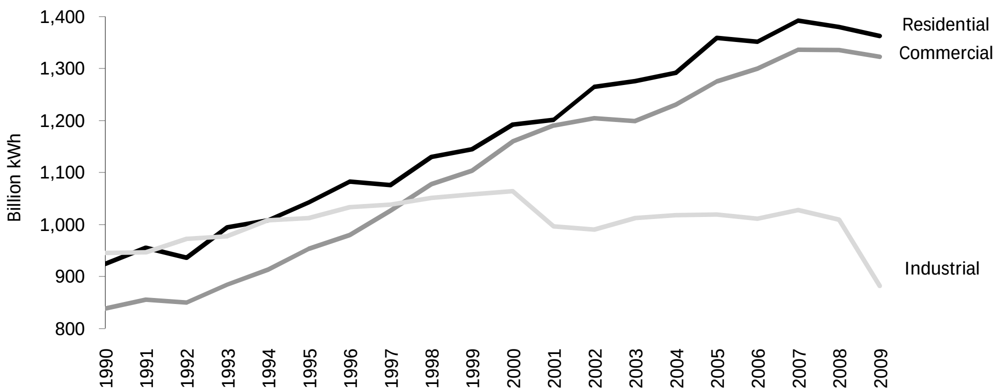


Figure 3-9: Electric Generation Retail Sales by End-Use Sector

Note: The transportation end-use sector consumes minor quanties of electricity.

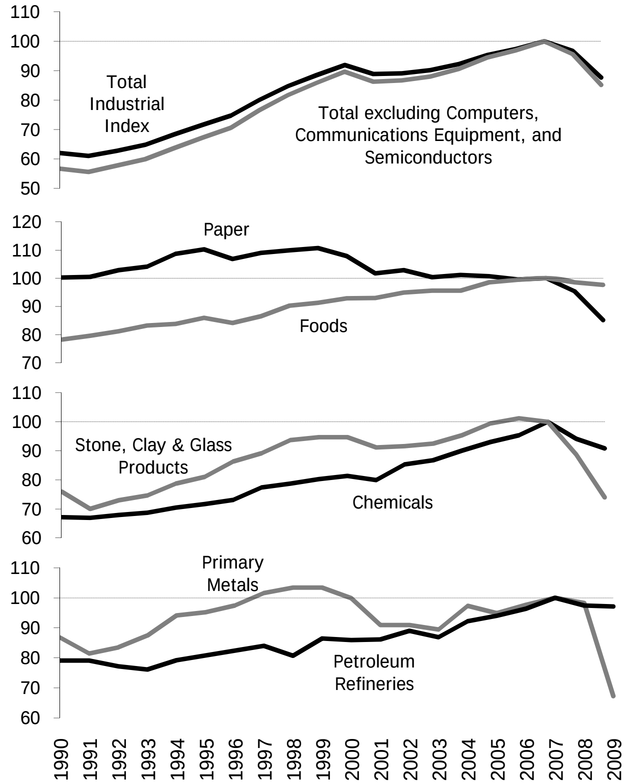


Figure 3-10: Industrial Production Indexes (Index 2007=100)

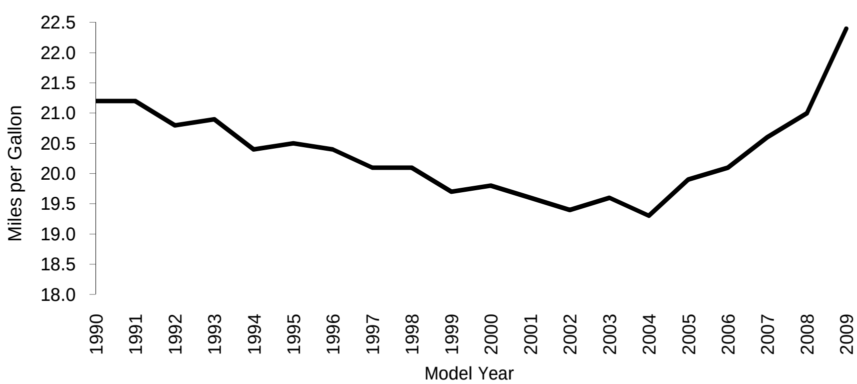


Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2009

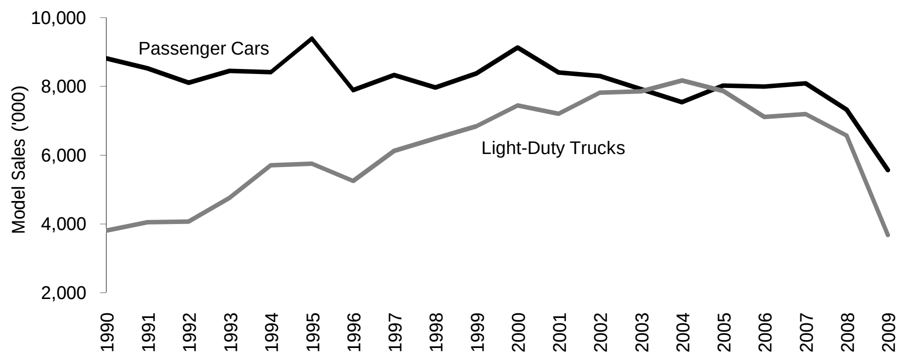


Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2009

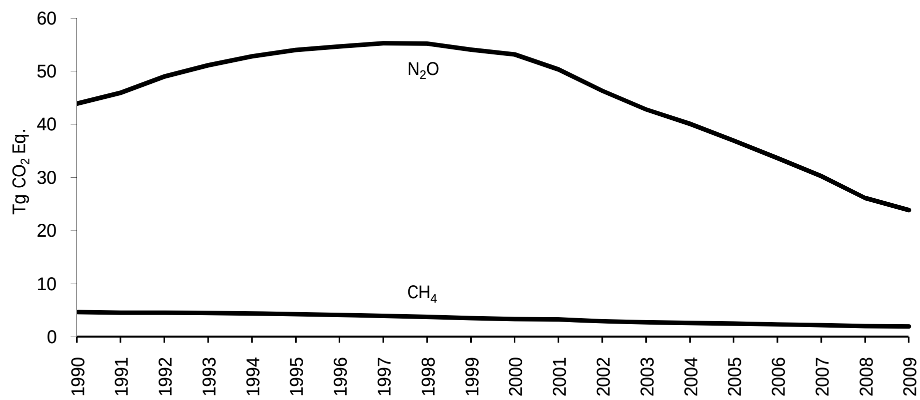


Figure 3-13: Mobile Source CH_4 and N_2O Emissions

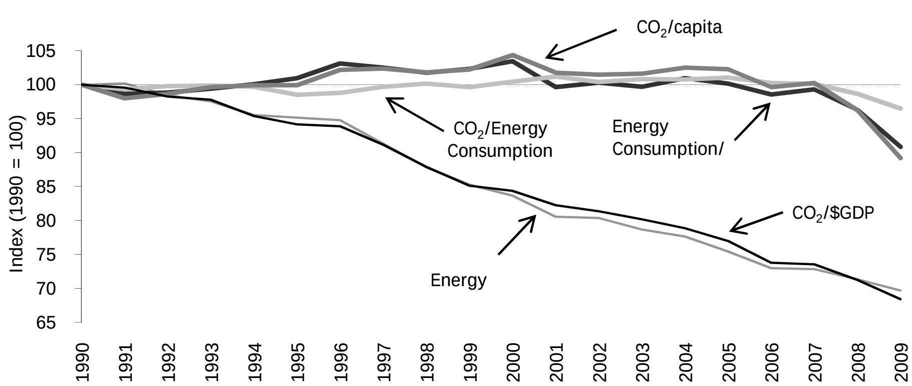


Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

Exhibit 4

U.S. EPA (2011), “Inventory of U.S. Greenhouse Gas Emissions and Sinks: Fast Facts”

Fast Facts Fast Facts Fast Facts

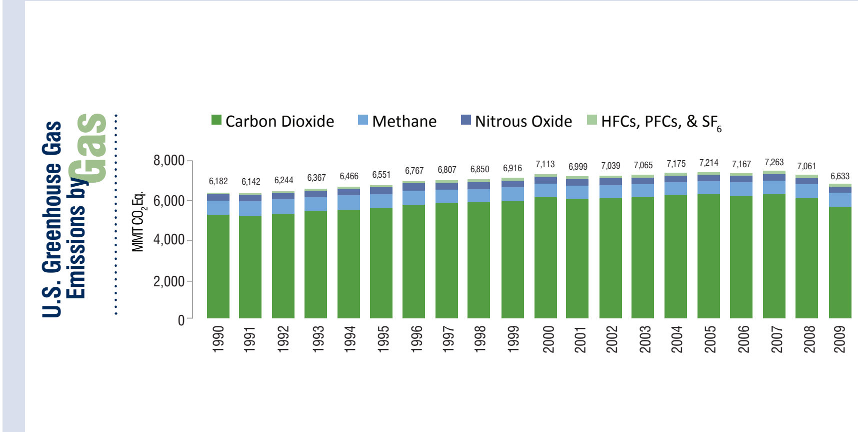
Inventory of U.S. Greenhouse Gas Emissions and Sinks

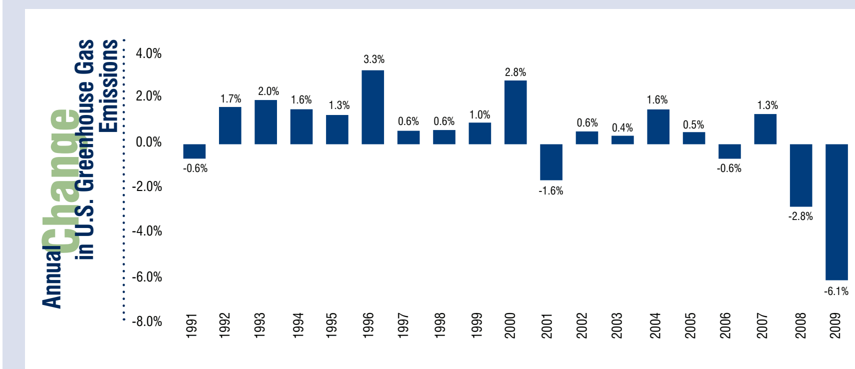
U.S. Greenhouse Gas Emissions and Sinks (MMT CO_2 Equivalents)

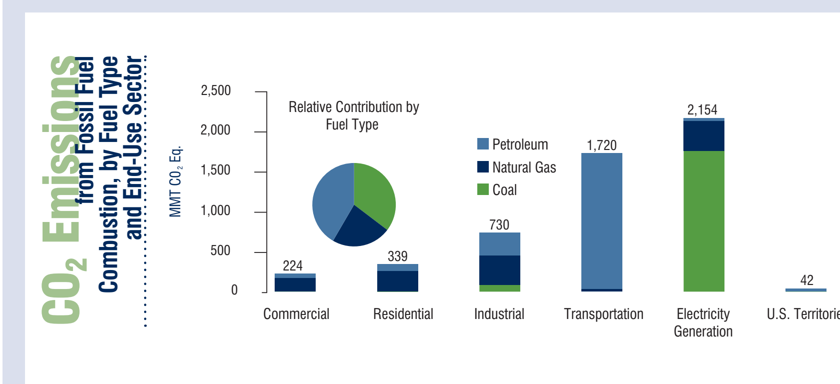
Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Change from 1990 to 2009: Absolute	Change from 1990 to 2009: Percent
CO_2	**5,099.7**	**5,055.0**	**5,158.2**	**5,270.8**	**5,354.3**	**5,422.8**	**5,602.5**	**5,681.2**	**5,713.9**	**5,796.6**	**5,975.0**	**5,873.3**	**5,912.6**	**5,966.0**	**6,076.7**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**	**405.5**	**8 %**
Fossil Fuel Combustion	4,738.4	4,698.2	4,799.1	4,909.8	4,977.4	5,031.5	5,215.9	5,284.0	5,316.2	5,391.1	5,594.8	5,521.9	5,557.6	5,621.1	5,708.0	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0	470.6	10 %
Non-Energy Use of Fuels	118.6	124.4	123.5	124.7	133.5	139.2	136.8	144.3	158.7	167.9	144.9	133.9	136.0	131.4	151.3	143.4	145.6	137.2	141.0	123.4	4.7	4 %
Iron and Steel Production & Metallurgical Coke Production	99.5	90.6	91.0	87.1	89.7	93.3	91.3	92.7	86.5	84.3	85.9	75.6	71.9	69.5	68.0	65.9	68.8	71.0	66.0	41.9	(57.7)	(58)%
Natural Gas Systems	37.6	37.8	37.5	40.9	41.0	42.5	40.0	39.6	29.6	30.7	29.9	29.4	30.2	29.0	28.7	29.9	30.8	31.1	32.8	32.2	(5.4)	(14)%
Cement Production	33.3	32.5	32.8	34.6	36.1	36.2	36.4	37.6	38.5	39.3	40.4	40.6	42.2	42.3	44.8	45.2	45.8	44.5	40.5	29.0	(4.3)	(13)%
Incineration of Waste	8.0	8.0	9.5	9.8	10.9	11.3	11.9	11.9	10.8	11.0	11.1	11.4	11.8	12.1	12.4	12.5	12.5	12.7	12.2	12.3	4.3	54 %
Ammonia Production and Urea Consumption	16.8	16.8	17.5	17.8	18.4	17.8	17.7	18.0	19.0	17.6	16.4	13.3	14.2	12.4	13.2	12.8	12.3	14.0	11.9	11.8	(5.0)	(30)%
Lime Production	11.5	11.4	11.8	12.1	12.6	13.3	14.1	14.3	14.6	14.3	14.1	13.6	13.1	13.8	14.5	14.4	15.1	14.6	14.3	11.2	(0.3)	(3)%
Cropland Remaining Cropland	7.1	7.3	6.9	6.4	6.8	7.0	7.0	7.0	7.7	7.5	7.5	7.8	8.5	8.3	7.6	7.9	7.9	8.2	8.7	7.8	0.7	11 %
Limestone and Dolomite Use	5.1	4.5	4.6	4.3	4.8	6.7	7.2	6.7	6.9	7.6	5.1	4.8	5.6	4.1	5.9	6.8	8.0	7.7	6.3	7.6	2.5	49 %
Soda Ash Production and Consumption	4.1	4.0	4.1	4.0	4.0	4.3	4.2	4.4	4.3	4.2	4.2	4.1	4.1	4.1	4.2	4.2	4.2	4.1	4.1	4.3	0.1	3 %
Aluminum Production	6.8	6.9	6.8	6.2	5.5	5.7	6.0	6.0	6.2	6.3	6.1	4.4	4.5	4.5	4.2	4.1	3.8	4.3	4.5	3.0	(3.8)	(56)%
Petrochemical Production	3.3	3.4	3.6	3.8	4.0	4.1	4.1	4.4	4.5	4.6	4.5	4.2	4.3	4.1	4.3	4.2	3.8	3.9	3.4	2.7	(0.6)	(17)%
Carbon Dioxide Consumption	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.8	1.0	1.3	1.2	1.3	1.7	1.9	1.8	1.8	0.3	24 %
Titanium Dioxide Production	1.2	1.2	1.4	1.4	1.5	1.5	1.5	1.7	1.7	1.7	1.8	1.7	1.8	1.8	2.1	1.8	1.8	1.9	1.8	1.5	0.3	29 %
Ferroalloy Production	2.2	1.9	2.0	1.9	2.0	2.0	2.1	2.2	2.2	2.2	1.9	1.5	1.3	1.3	1.4	1.4	1.5	1.6	1.6	1.5	(0.7)	(32)%
Wetlands Remaining Wetlands	1.0	1.0	0.9	1.0	0.9	1.0	0.9	1.0	1.1	1.2	1.2	1.1	1.0	1.0	1.1	1.1	0.9	1.0	1.0	1.1	0.1	5 %
Phosphoric Acid Production	1.5	1.4	1.5	1.3	1.5	1.5	1.6	1.5	1.6	1.5	1.4	1.3	1.3	1.4	1.4	1.4	1.2	1.2	1.2	1.0	(0.5)	(32)%
Zinc Production	0.7	0.9	0.9	1.0	1.0	0.9	1.0	1.0	0.9	0.9	1.0	0.8	0.8	1.2	1.1	1.1	1.1	1.1	1.2	1.0	0.3	45 %
Lead Production	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.5	+	2 %
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	(0.1)	(17)%
Silicon Carbide Production and Consumption	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	(0.2)	(61)%
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861.5)*	*(833.1)*	*(821.0)*	*(772.0)*	*(873.2)*	*(812.6)*	*(711.1)*	*(741.4)*	*(617.7)*	*(534.1)*	*(576.6)*	*(661.7)*	*(864.8)*	*(1,005.9)*	*(1,052.5)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*	*(153.5)*	*18 %*
Wood Biomass and Ethanol Consumption[b]	*219.4*	*220.2*	*230.6*	*225.8*	*232.3*	*236.9*	*241.3*	*235.6*	*218.2*	*221.5*	*227.4*	*203.3*	*204.6*	*209.8*	*225.2*	*229.8*	*234.8*	*242.3*	*253.1*	*245.0*	*25.6*	*12 %*
International Bunker Fuels[c]	*111.8*	*120.7*	*113.3*	*102.2*	*104.7*	*99.8*	*107.5*	*110.2*	*119.5*	*101.8*	*98.5*	*96.6*	*104.2*	*99.8*	*114.1*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*	*11.3*	*10 %*
CH_4	**674.9**	**676.4**	**680.8**	**671.6**	**685.4**	**678.0**	**684.3**	**662.6**	**656.7**	**650.2**	**659.9**	**655.9**	**658.0**	**649.7**	**636.7**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**	**11.4**	**2 %**
Natural Gas Systems	189.8	191.5	191.9	194.8	197.7	198.4	202.2	201.7	201.2	195.4	209.3	215.5	217.2	214.1	204.8	190.4	217.7	205.2	211.8	221.2	31.4	17 %
Enteric Fermentation	132.1	132.3	136.4	138.0	140.3	143.5	142.5	139.7	138.1	138.1	136.5	135.7	136.1	134.3	134.4	136.5	138.8	141.0	140.6	139.8	7.7	6 %
Landfills	147.4	148.4	149.0	148.4	146.7	139.4	136.0	127.0	119.7	114.7	111.7	108.2	108.5	113.7	109.7	112.5	111.7	111.3	115.9	117.5	(29.9)	(20)%
Coal Mining	84.1	81.1	79.0	67.7	68.1	67.1	66.8	66.4	66.8	62.9	60.4	60.4	56.8	56.8	58.1	56.9	58.2	57.9	67.1	71.0	(13.0)	(16)%
Manure Management	31.7	33.2	32.0	33.5	35.7	36.8	36.2	38.0	41.4	41.9	42.4	44.2	45.4	42.1	44.3	46.6	46.7	50.7	49.4	49.5	17.7	56 %
Petroleum Systems	35.4	35.6	34.7	33.8	33.7	33.4	33.3	33.2	32.9	31.9	31.5	31.5	31.1	30.4	29.9	29.4	29.4	30.0	30.2	30.9	(4.4)	(13)%
Wastewater Treatment	23.5	23.9	24.3	24.4	24.7	24.8	24.9	25.2	25.2	25.3	25.2	24.7	24.7	24.5	24.6	24.3	24.5	24.4	24.5	24.5	1.0	4 %
Forest Land Remaining Forest Land	3.2	2.8	4.2	2.6	7.7	4.3	12.2	2.4	3.2	11.3	14.3	8.3	12.6	8.0	4.6	9.8	21.6	20.0	11.9	7.8	4.6	144 %
Rice Cultivation	7.1	7.0	7.9	7.0	8.2	7.6	7.0	7.5	7.9	8.3	7.5	7.6	6.8	6.9	7.6	6.8	5.9	6.2	7.2	7.3	0.2	3 %
Stationary Combustion	7.4	7.6	7.8	7.3	7.2	7.1	7.4	6.7	6.2	6.3	6.6	6.2	6.2	6.4	6.5	6.6	6.2	6.5	6.5	6.2	(1.3)	(17)%
Abandoned Underground Coal Mines	6.0	6.2	6.7	6.9	8.1	8.2	8.5	7.6	6.9	7.0	7.4	6.7	6.2	6.0	5.8	5.5	5.5	5.6	5.9	5.5	(0.5)	(9)%
Mobile Combustion	4.7	4.6	4.5	4.5	4.4	4.3	4.1	4.0	3.8	3.5	3.4	3.3	2.9	2.7	2.6	2.5	2.3	2.2	2.0	2.0	(2.7)	(58)%
Composting	0.3	0.4	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.3	1.3	1.3	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.3	421 %
Petrochemical Production	0.9	0.9	0.9	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.2	1.1	1.2	1.1	1.2	1.1	1.0	1.0	0.9	0.8	(+)	(2)%
Iron and Steel Production & Metallurgical Coke Production	1.0	0.8	0.9	0.9	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.6	0.4	(0.6)	(62)%
Field Burning of Agricultural Residues	0.3	0.2	0.3	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	(+)	(8)%
Ferroalloy Production	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	(+)	(40)%
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	(+)	(67)%
Incineration of Waste	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	(+)	(23)%
International Bunker Fuels[c]	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*(+)*	*(14)%*
N_2O	**315.2**	**326.5**	**317.3**	**336.9**	**336.2**	**342.8**	**362.9**	**339.7**	**343.4**	**334.2**	**341.0**	**342.2**	**331.7**	**317.6**	**320.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**	**(19.6)**	**(6)%**
Agricultural Soil Management	197.8	207.7	195.4	212.0	203.5	207.6	219.3	209.7	217.6	203.2	206.8	220.4	208.8	202.4	211.8	211.3	208.9	209.4	210.7	204.6	6.8	3 %
Mobile Combustion	43.9	46.0	49.0	51.1	52.8	54.0	54.7	55.3	55.2	54.1	53.2	50.3	46.3	42.8	40.1	36.9	33.6	30.3	26.1	23.9	(20.0)	(46)%
Manure Management	14.5	14.7	14.8	14.5	15.3	15.7	15.6	15.8	16.0	16.7	17.1	17.0	17.4	16.9	16.9	17.3	18.0	18.1	17.9	17.9	3.4	23 %
Nitric Acid Production	17.7	17.7	18.1	18.4	19.4	19.7	20.5	21.0	20.7	19.9	19.4	15.8	17.1	16.0	15.9	16.5	16.2	19.2	16.4	14.6	(3.1)	(18)%
Stationary Combustion	12.8	12.8	13.0	13.2	13.3	13.3	13.9	14.1	14.0	14.0	14.6	14.1	14.0	14.3	14.5	14.7	14.4	14.6	14.2	12.8	(+)	(+)%
Forest Land Remaining Forest Land	2.7	2.3	3.5	2.2	6.4	3.7	10.2	2.2	2.9	9.7	12.1	7.2	10.7	7.0	4.1	8.4	18.0	16.7	10.1	6.7	4.1	152 %
Wastewater Treatment	3.7	3.8	3.9	4.0	4.0	4.0	4.1	4.1	4.2	4.4	4.5	4.6	4.5	4.6	4.7	4.8	4.8	4.9	5.0	5.0	1.3	36 %
N_2O from Product Uses	4.4	4.3	4.0	4.6	4.6	4.6	4.6	4.9	4.9	4.9	4.9	4.9	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	(+)	(+)%
Adipic Acid Production	15.8	15.4	13.5	14.6	14.2	17.6	17.4	9.8	5.4	4.9	5.5	4.7	5.2	5.7	3.8	5.0	4.3	3.7	2.0	1.9	(13.8)	(88)%
Composting	0.4	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.4	1.4	1.4	1.6	1.7	1.7	1.8	1.8	1.9	1.8	1.5	421 %
Settlements Remaining Settlements	1.0	1.0	1.1	1.2	1.3	1.2	1.1	1.1	0.9	0.8	1.1	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.5	1.5	0.5	55 %
Incineration of Waste	0.5	0.4	0.5	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	(0.1)	(23)%
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+	3 %
Wetlands Remaining Wetlands	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	(+)	(7)%
International Bunker Fuels[c]	*1.1*	*1.1*	*1.1*	*1.0*	*1.0*	*0.9*	*1.0*	*1.0*	*1.1*	*1.0*	*0.9*	*0.9*	*1.0*	*0.9*	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*+*	*4 %*
HFCs, PFCs, and SF_6	**92.0**	**84.2**	**87.9**	**87.8**	**90.4**	**107.2**	**116.8**	**123.7**	**136.1**	**135.2**	**136.8**	**127.2**	**136.3**	**131.8**	**141.3**	**145.4**	**147.4**	**153.7**	**152.2**	**146.1**	**54.1**	**59 %**
Substitution of Ozone Depleting Substances	0.3	0.6	1.7	5.5	12.5	29.0	40.3	51.4	58.8	66.6	74.3	80.4	87.1	92.9	99.0	104.2	109.4	112.3	115.5	120.0	119.6	36,143 %
HCFC-22 Production	36.4	32.7	36.4	33.1	31.5	33.0	31.2	30.1	39.5	30.4	28.6	19.7	21.1	12.3	17.2	15.8	13.8	17.0	13.6	5.4	(31.0)	(85)%
Semiconductor Manufacture	2.9	2.9	2.9	3.6	4.0	4.9	5.5	5.8	7.1	7.2	6.2	4.4	4.3	4.3	4.3	4.4	4.7	4.8	5.1	5.3	2.4	83 %
Aluminum Production	18.5	15.6	14.3	13.7	12.1	11.8	12.4	10.8	8.6	8.5	8.6	3.5	5.2	3.8	2.8	3.0	2.5	3.8	2.7	1.6	(17.0)	(91)%
Electrical Transmission and Distribution	28.4	27.2	27.1	26.3	24.7	22.8	20.9	19.1	16.3	16.6	16.0	16.3	15.6	15.1	15.1	15.1	14.1	13.2	13.3	12.8	(15.6)	(55)%
Magnesium Production and Processing	5.4	5.2	5.5	5.6	5.4	5.6	6.6	6.4	5.9	5.9	3.0	2.9	2.9	3.4	2.9	2.9	2.9	2.6	1.9	1.1	(4.4)	(81)%
Total	**6,181.8**	**6,142.1**	**6,244.2**	**6,367.2**	**6,466.4**	**6,550.7**	**6,766.5**	**6,807.1**	**6,850.2**	**6,916.2**	**7,112.7**	**6,998.6**	**7,038.5**	**7,065.1**	**7,174.8**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**451.4**	**7 %**
Net Emissions (Sources and Sinks)	**5,320.3**	**5,309.1**	**5,423.2**	**5,595.1**	**5,593.2**	**5,738.1**	**6,055.4**	**6,065.7**	**6,232.5**	**6,382.1**	**6,536.1**	**6,336.8**	**6,173.7**	**6,059.3**	**6,122.3**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**	**297.9**	**6 %**

1990–2009 Trends

- Total GHG emissions rose 7.3 percent since 1990
- Dominant gas emitted was CO_2, mostly from fossil fuel combustion
- Methane emissions increased by 1.7 percent
- Nitrous oxide emissions decreased by 6.2 percent
- HFC, PFC, and SF_6 emissions have grown by 58.8 percent







EPA United States Environmental Protection Agency
Office of Atmospheric Programs (6207J)
April 2011
EPA 430-F-11-007

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

Note: Totals may not sum due to independent rounding. Emissions weighted using GWP values from *IPCC Second Assessment Report* (1996) in keeping with UNFCCC reporting guidelines.

Reference Tables and Conversions

Inventory of U.S. Greenhouse Gas Emissions and Sinks

Conversions and Units

Global Warming Potentials
(100 Year Time Horizon)

Gas	GWP SAR[a]	GWP AR4[b]
Carbon dioxide (CO_2)	1	1
Methane (CH_4)*	21	25
Nitrous oxide (N_2O)	310	298
HFC-23	11,700	14,800
HFC-125	2,800	3,500
HFC-134a	1,300	1,430
HFC-143a	3,800	4,470
HFC-152a	140	124
HFC-227ea	2,900	3,220
HFC-236fa	6,300	9,810
HFC-4310mee	1,300	1,640
CF_4	6,500	7,390
C_2F_6	9,200	12,200
C_4F_{10}	7,000	8,860
C_6F_{14}	7,400	9,300
SF_6	23,900	22,800

[a] *IPCC Second Assessment Report* (1996)
[b] *IPCC Fourth Assessment Report* (2007)
* The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Note: GWP values from the *IPCC Second Assessment Report* are used in accordance with UNFCCC guidelines.

Global Warming Potential (GWP) is defined as the cumulative radiative forcing effects of a gas over a specified time horizon resulting from the emission of a unit mass of gas relative to a reference gas. The GWP-weighted emissions of direct greenhouse gases in the U.S. Inventory are presented in terms of equivalent emissions of carbon dioxide (CO_2), using units of million metric tons of carbon dioxide equivalents (MMT CO_2 Eq.).

Conversion:
1 million metric tons $= 10^6$ metric tons $= 10^9$ kg

The molecular weight of carbon is 12, and the molecular weight of oxygen is 16; therefore, the molecular weight of CO_2 is 44 (i.e., $12+[16\times2]$), as compared to 12 for carbon alone. Thus, the weight ratio of carbon to carbon dioxide is 12/44.

Conversion from gigagrams of gas to million metric tons of carbon dioxide equivalents:

$$\text{MMT } CO_2 \text{ Eq.} = \left(\frac{\text{Gg}}{\text{of gas}}\right) \times (\text{GWP}) \times \left(\frac{\text{MMT}}{1{,}000 \text{ Gg}}\right)$$

Energy Conversions

The common energy unit used in international reports of greenhouse gas emissions is the joule. A joule is the energy required to move an object one meter with the force of one Newton. A terajoule (TJ) is one trillion (10^{12}) joules. A British thermal unit (Btu, the customary U.S. energy unit) is the quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit at or near 39.2 Fahrenheit.

1 TJ =
- 2.388×10^{11} calories
- 23.88 metric tons of crude oil equivalent
- 9.478×10^8 Btu
- 277,800 kilowatt-hours

Energy Units

Btu	British thermal unit	1 Btu
MBtu	Thousand Btu	1×10^3 Btu
MMBtu	Million Btu	1×10^6 Btu
BBtu	Billion Btu	1×10^9 Btu
TBtu	Trillion Btu	1×10^{12} Btu
QBtu	Quadrillion Btu	1×10^{15} Btu

Unit Conversions

1 pound	= 0.454 kilograms	= 16 ounces	
1 kilogram	= 2.205 pounds	= 35.27 ounces	
1 short ton	= 0.9072 metric tons	= 2,000 pounds	
1 metric ton	= 1.1023 short tons	= 1,000 kilograms	
1 cubic foot	= 0.02832 cubic meters	= 28.3168 liters	
1 cubic meter	= 35.315 cubic feet	= 1,000 liters	
1 U.S. gallon	= 3.78541 liters	= 0.03175 barrels	= 0.02381 barrels petroleum
1 liter	= 0.2642 U.S. gallons	= 0.0084 barrels	= 0.0063 barrels petroleum
1 barrel	= 31.5 U.S. gallons	= 119 liters	= 0.75 barrels petroleum
1 barrel petroleum	= 42 U.S. gallons	= 159 liters	
1 foot	= 0.3048 meters	= 12 inches	
1 meter	= 3.28 feet	= 39.37 inches	
1 mile	= 1.609 kilometers	= 5,280 feet	
1 kilometer	= 0.6214 miles	= 3,280.84 feet	
1 square mile	= 2.590 square kilometers	= 640 acres	
1 square kilometer	= 0.386 square miles	= 100 hectares	
1 acre	= 43,560 square feet	= 0.4047 hectares	= 4,047 square meters

Guide to Metric Unit Prefixes

Prefix/Symbol	Factor	
Tera (T)	10^{12}	1,000,000,000,000
Giga (G)	10^9	1,000,000,000
Mega (M)	10^6	1,000,000
Kilo (k)	10^3	1,000
Hecto (h)	10^2	100
Deca (da)	10^1	10
—	10^0	1
Deci (d)	10^{-1}	.1
Centi (c)	10^{-2}	.01
Milli (m)	10^{-3}	.001
Micro (μ)	10^{-6}	.000001
Nano (n)	10^{-9}	.000000001
Pico (p)	10^{-12}	.000000000001

Economic Sectors

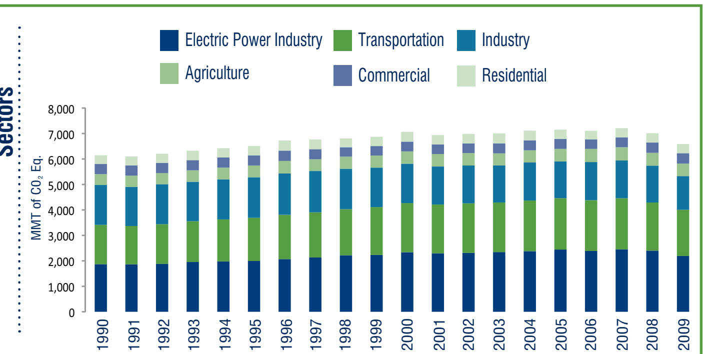
U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO_2 Eq.)

Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**

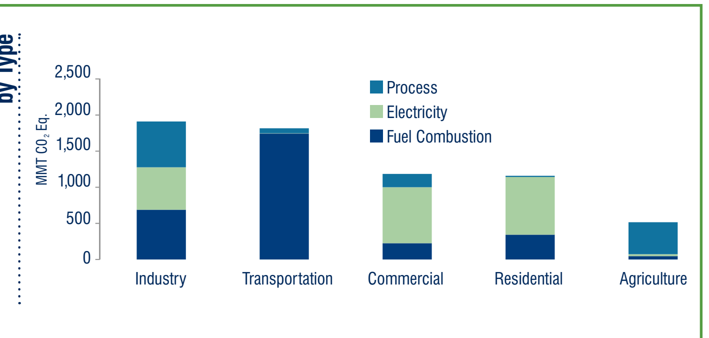
U.S. Greenhouse Gas Emissions Allocated to Economic Sectors with Electricity Distributed (MMT CO_2 Eq.)

Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**

Emissions from Economic Sectors



2009 Economic Sector Emissions by Type



Carbon Information

Conversion Factors to Energy Units (Heat Equivalents)
Heat Contents and Carbon Content Coefficients of Various Fuel Types

Converting Various Physical Units to Energy Units—The values in the following table provide conversion factors from physical units to energy equivalent units and from energy units to carbon contents. These factors can be used as default factors, if local data are not available.

Fuel Type	Heat Content	Carbon (C) Content Coefficients	Carbon Dioxide (CO_2) per Physical Unit
Solid Fuels	**Million Btu/Metric Ton**	**kg C/Million Btu**	**kg CO_2/Metric Ton**
Anthracite Coal	24.88	28.28	2,579.9
Bituminous Coal	26.33	25.44	2,456.6
Sub-bituminous Coal	18.89	26.50	1,835.9
Lignite	14.18	26.65	1,385.6
Coke	27.56	31.00	3,131.9
Unspecified Coal	27.56	25.34	2,560.0
Gas Fuels	**Btu/Cubic Foot**	**kg C/Million Btu**	**kg CO_2/Cubic Foot**
Natural Gas	1,026	14.46	0.0544
Liquid Fuels	**Million Btu/Petroleum Barrel**	**kg C/Million Btu**	**kg CO_2/Petroleum Barrel**
Motor Gasoline	5.22	19.46	372.2
Distillate Fuel Oil	5.83	20.17	430.8
Residual Fuel Oil	6.29	20.48	472.1
Jet Fuel	5.67	19.70	409.5
Aviation Gasoline	5.05	18.86	349.0
LPG	3.55	16.83	219.3
Kerosene	5.67	19.96	415.1
Still Gas	6.00	18.20	400.3
Petroleum Coke	6.02	27.85	615.1
Pentanes Plus	4.62	19.10	323.6
Unfinished Oils	5.83	20.31	433.8

Note: For fuels with variable heat contents and carbon content coefficients, 2009 U.S. average values are presented. All factors are presented in gross calorific values (GCV) (i.e., higher heating values). LRG = Liquid Refinery Gas. Miscellaneous products includes all finished products not otherwise classified, (e.g., aromatic extracts and tars, absorption oils, ram-jet fuel, synthetic natural gas, naptha-type jet fuel, and specialty oils).

CO_2 Emissions from Fossil Fuel Combustion = **Fuel Combusted × Carbon Content Coefficient × Fraction Oxidized × (44/12)**

May include adjustments for carbon stored in fossil fuel-based products, emissions from international bunker fuels, or emissions from territories.

Carbon Intensity of Different Fuel Types

The amount of carbon in fossil fuels per unit of energy content varies significantly by fuel type. For example, coal contains the highest amount of carbon per unit of energy, while petroleum has about 25 percent less carbon than coal, and natural gas about 45 percent less.

For more information on calculating CO_2 emissions per kWh, download eGRID at:
http://www.epa.gov/cleanenergy/egrid

For other related information, see:
http://www.epa.gov/climatechange and **http://unfccc.int**

Download the Inventory at: **http://www.epa.gov/climatechange/emissions/usinventoryreport.html**

Source for all data: *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2009* (EPA 2011)

Exhibit 5

BLM, *Record of Decision Environmental Impact Statement for the North Porcupine Field Coal Lease Application, WYW173408* (October 2011)

RECORD OF DECISION
Environmental Impact Statement for the North Porcupine Coal Lease Application
WYW173408

October 2011

The BLM's multiple-use mission is to sustain the health and productivity of the public lands for the use and enjoyment of present and future generations. The Bureau accomplishes this by managing such activities as outdoor recreation, livestock grazing, mineral development, and energy production, and by conserving natural, historical, cultural, and other resources on public lands.

BLM/WY/PL-11/056+1320

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

RECORD OF DECISION

NORTH PORCUPINE LEASE BY APPLICATION
WYW173408
CAMPBELL COUNTY, WYOMING

INTRODUCTION

On September 29, 2006, BTU Western Resources, Inc. (BTU), a subsidiary of Peabody Energy Corporation (PEC), filed an application with the Bureau of Land Management (BLM) for Federal coal reserves in three maintenance tracts encompassing approximately 5,116.65 acres and 598 million tons of coal as estimated by the applicant. The tracts are located west, northwest, and north of and immediately adjacent to the North Antelope Rochelle Mine in Campbell County, Wyoming (Appendix 1, Figure 1). The mine is operated by Powder River Coal, LLC (PRC), a subsidiary of PEC. The application was made pursuant to the Leasing on Application regulations found in the Code of Federal Regulations at 43 CFR Subpart 3425.1.

On October 12, 2007, BTU filed a request with the BLM to modify its application and increase the lease area and coal volume to approximately 8,981.74 acres and 1,179.1 million tons of coal. BLM reviewed the modified tract configuration and notified the company that their application had been modified. BLM determined that the application would be processed as two separate maintenance tracts and, if decisions were made to lease the tracts, a separate competitive lease sale would be held for each tract. Located approximately 12 miles southeast of Wright, the two nominated tracts on the north side of the mine were combined and are referred to as the North Porcupine Lease By Application (LBA) tract with assigned case file number WYW173408. Located approximately 14 miles southeast of Wright, the remaining nominated tract on the west side of the mine is referred to as the South Porcupine LBA tract with assigned case file number WYW176095.

BTU has applied to lease Federal coal reserves in order to extend the life of the North Antelope Rochelle Mine. The BLM refers to these types of applications as maintenance tracts. A maintenance tract is a tract of Federal coal that is adjacent to, and can be mined by, an existing active coal mine. As applied for, the North Porcupine LBA tract includes a total of approximately 5,795.78 acres (Appendix 1, Figure 2). BTU estimates that, as applied for, the tract includes approximately 601.2 million tons of recoverable coal reserves in Campbell County, Wyoming.

The North Porcupine LBA tract was evaluated in the *Wright Area Coal Lease Applications Environmental Impact Statement* (EIS). The EIS analyzed the proposed leasing of six Federal coal tracts located in the Wright Area of the Wyoming portion of the Powder River Basin. The Proposed Action analyzed in the EIS is to hold one competitive sealed-bid lease sale and issue a lease for the Federal coal lands included in the North Porcupine LBA tract as applied for by BTU. The Proposed Action assumes that the applicant would be the successful bidder on the tract, and that the tract would be mined as a maintenance lease for the existing mine. According to the applicant, the North Antelope Rochelle Mine needs the Federal coal included in the North Porcupine coal lease area in order to extend the life of the mine. The applicant would recover the Federal coal using the same methodology, machinery, and facilities that are currently being used to recover the coal in the existing North Antelope Rochelle Mine coal leases. If the lease for the North Porcupine LBA tract is acquired as it was applied for, PRC anticipates that it would extend the life of the North Antelope Rochelle Mine by approximately 6.3 years.

The North Antelope Rochelle Mine has a permit to conduct mining operations approved by the Wyoming Department of Environmental Quality Land Quality Division (WDEQ/LQD) and a Mineral Leasing Act (MLA) of 1920, as amended, mining plan approved by the Secretary of the Interior to conduct surface coal mining operations on their existing coal leases. The mine complies with the requirements of the Clean Air Act (CAA) through an air quality permit approved by the Air Quality Division of the Wyoming Department of Environmental Quality (WDEQ/AQD) which currently allows mining of up to 140 million tons of coal per year.

BLM administers the Federal Coal Leasing Program under the MLA as amended by the Federal Coal Leasing Amendments Act of 1976. If any proposed lease tract contains surface lands which are under the jurisdiction of any Federal agency other than the Department of Interior (USDI) or are occupied by a qualified surface owner, that agency or individual must consent to the issuance of the lease, and in the case of a Federal agency, may prescribe terms and conditions to be imposed on that lease (43 CFR 3400.3-1 and 3420.4-2). There are no qualified surface owners within the selected configuration for the North Porcupine LBA tract. Powder River Coal, LLC, School Creek Coal Resources, Jerry N. and Rhonda Wilkinson, and Western Railroad Properties, Inc. own the private lands contained within the North Porcupine LBA tract as analyzed in the Wright Area EIS under Alternative 2.

The selected configuration for the North Porcupine tract (Appendix 1, Figure 3) also includes approximately 5,120 acres, more or less, of National Forest System lands in the Thunder Basin National Grassland (TBNG) administered by the USDA-Forest Service (FS). As required by 43 CFR 3420.4-2, the FS has provided consent to BLM to lease the FS-administered lands that were included in the North Porcupine tract. The FS signed their Record of Decision on September 30, 2011. Their prescribed terms and conditions for the North Porcupine coal tract are included in Appendix 2. The FS ROD is subject to appeal under FS administrative procedures. In the event of a FS ROD appeal, BLM's decision would not be implemented until the FS appeal process is completed.

BACKGROUND

Lease by Application Process

In the Powder River Basin (PRB), maintenance tracts are generally nominated for leasing by companies operating adjacent existing mines. To process an LBA, the BLM must evaluate the quantity, quality, maximum economic recovery (MER), and fair market value (FMV) of the Federal coal. The BLM must also evaluate the environmental and socioeconomic impacts of leasing and mining the Federal coal in accordance with the requirements of the National

Environmental Policy Act of 1969 (NEPA). BLM prepared the Wright Area Coal EIS to evaluate and disclose potential impacts of leasing the Federal coal in six Wright Area coal tracts, including the North Porcupine tract. Although leasing the North Porcupine would not authorize mining operations on the tract, the EIS evaluates the potential impacts of mining the North Porcupine tract because mining is a logical consequence of issuing a lease for a maintenance tract of coal.

The Office of Surface Mining Reclamation and Enforcement (OSM) is a cooperating agency on the Wright Area EIS. OSM is the Federal agency with the primary responsibility to administer programs that regulate surface coal mining in accordance with Section 503 of the Surface Mining Control and Reclamation Act of 1977 (SMCRA). OSM also recommends approval, approval with conditions, or disapproval of the MLA mining plan to the Assistant Secretary of the Interior, Lands and Minerals Management. The FS is a cooperating agency since a portion of the Wright Area proposed lands for leasing lie within the TBNG.

The WDEQ/LQD, WDEQ/AQD, Wyoming Department of Transportation (WYDOT), and the Converse County Board of Commissioners are also cooperating agencies on this EIS. WDEQ/LQD has a cooperative agreement with the Secretary of the Interior to regulate surface coal mining operations on Federal and non-Federal lands within the State of Wyoming. WDEQ/AQD regulates air borne emissions in Wyoming and administers the air quality standards developed by the Environmental Protection Agency (EPA). WYDOT's responsibilities include maintaining state roads and highways, planning and supervising road improvement work, and supporting airports and aviation in the state. The responsibilities of the Converse County Board of Commissioners include but are not limited to the management and oversight of county roads, facilities, and planning and zoning rules in the county.

By law and regulation, the LBA process is an open, public, competitive sealed-bid process. Bidding at any potential sale is not restricted to the applicant. In order for BLM to award and issue a coal lease, the highest bid received must meet or exceed fair market value of the coal as determined by BLM's economic evaluation.

BTU filed the LBA because the North Porcupine, as applied for, is adjacent to their existing approved mining operations at the North Antelope Rochelle Mine and the Federal coal can be mined using their existing mine facilities, equipment, and employees (Appendix 1, Figure 1). In the Wright Area Coal EIS, the alternatives that are analyzed in detail assume that the applicant would be the successful bidder if a competitive coal lease sale is held.

History of Coal Leasing Activity in the Wyoming Portion of the Decertified Powder River Coal Region

Since decertification of the Powder River Federal Coal Region in 1990, 22 Federal coal leases have been issued in Wyoming's Campbell and Converse counties under the LBA process with competitive sealed-bid sales. These leases include approximately 53,919 acres and 6.2 billion tons of mineable coal. Twenty of these leases were issued to the following producing mines for the purpose of extending operations at those mines: Jacobs Ranch (2), Black Thunder (3), North

Antelope Rochelle (4), Eagle Butte (2), Antelope (5), Buckskin (1), Cordero/Rojo (2), and the former North Rochelle (1).

The remaining two leases, the West Rocky Butte and the West Roundup, were issued to companies intending to open new mines. The West Rocky Butte lease was issued to Northwestern Resources Company in 1992. They planned to start a new mine to recover the coal included in the Rocky Butte and West Rocky Butte leases but the new mine was never developed. The Rocky Butte and West Rocky Butte leases are now held by Caballo Coal Company, a subsidiary of PEC, and are included in the Caballo Mine. The West Roundup lease was issued to West Roundup Resources, Inc., a subsidiary of PEC, and has been incorporated into the recently permitted School Creek Mine.

Pending Coal Leasing Applications and Other Proposed Projects in the Wyoming Powder River Basin

There are currently 11 Wyoming PRB maintenance coal lease applications being processed by BLM including the North Porcupine LBA tract and the recently completed Caballo West, Belle Ayr North, South Hilight Field, West Coal Creek, and South Porcupine LBA Records of Decision. As applied for, the pending coal lease applications comprise of approximately 30,462 acres and 3.292 billion tons of Federal coal (Appendix 1, Figure 1). The coal lease applications and applicant mines include the following: Belle Ayr North (*Belle Ayr Mine*), North Hilight Field (*Black Thunder Mine*), South Hilight Field (*Black Thunder Mine*), West Hilight Field (*Black Thunder Mine*), West Coal Creek (*Coal Creek Mine*), Caballo West (*Caballo Mine)*, Hay Creek II *(Buckskin Mine)*, West Jacobs Ranch *(Jacobs Ranch Mine)*, Maysdorf II *(Cordero Rojo Mine)*, South Porcupine *(North Antelope Rochelle Mine)*, and North Porcupine *(North Antelope Rochelle Mine)*.

In addition to coal leasing and mining, oil and gas leasing and development have also occurred in the area. Both conventional and coalbed natural gas (CBNG) wells have been drilled in and around the North Antelope Rochelle Mine and the North Porcupine LBA. Conventional and CBNG resources are currently being recovered from Federal and private oil and gas leases in the application area. Federal oil and gas lease ownership in the North Porcupine LBA area is described in detail in the Final EIS. Federal oil and gas lessees and private interests identified by the applicant were included on the mailing list for the Wright Area Coal EIS.

The EIS discusses energy development in and around the North Porcupine LBA. The discussion includes a summary of the results of an analysis of the conventional oil and gas drilling that has occurred in the area, prepared by the BLM Wyoming Reservoir Management Group (WSO-RMG). The analysis found that 14 conventional oil and gas wells were permitted and drilled on lands included in the North Porcupine BLM study area. Six conventional gas wells and three oil wells are still producing. Four oil wells and one conventional gas well have been plugged and abandoned.

The Wright Area Coal EIS includes a summary of the results of the BLM WSO-RMG analysis of the CBNG resources in the area. Most of the CBNG production in the area has occurred from the upper Fort Union Formation (Paleocene) Wyodak-Anderson coal seam, the same coal beds being mined by the surface coal operators. In the Wyoming portion of the PRB, CBNG has been produced from the Wyodak-Anderson zone since the late 1980s. According to data analyzed by the BLM WSO-RMG and the U.S. Geological Survey, measured gas content was minimal in all of the Wyodak-Anderson coal cores that were collected in the year 2000 at locations near the surface coal mines, indicating that the coal seams were already substantially depleted of CBNG in the vicinity of the mines. The EIS identifies 43 CBNG wells that have been drilled over time within the North Porcupine BLM study area. Forty-two of those wells have been producing and one well was shut in. CBNG wells that continue to produce in advance of coal mining assist in removing any remaining methane in the coal seams.

Several mechanisms can be used to facilitate recovery of the conventional oil and gas and CBNG resources prior to mining if the Federal coal in the tract is leased:

- BLM will attach a Multiple Mineral Development stipulation in the Federal coal lease which states that BLM has the authority to withhold approval of coal mining operations that would interfere with the development of mineral leases that were issued prior to the North Porcupine coal tract being leased (Appendix 2).

- Conventional oil and gas wells must be abandoned while mining and reclamation operations are in progress. If the value of the remaining oil and gas reserves justifies the expense of reestablishing production, the wells could be recompleted or redrilled following mining.

- BLM has a policy in place regarding CBNG-coal development conflicts (BLM Washington Office Instruction Memorandum (IM) No. 2006-153). The IM directs BLM decision-makers to optimize the recovery of both CBNG and conventional resources and to ensure that the public receives a reasonable return. This policy offers royalty incentives to CBNG operators to accelerate production in order to recover the natural gas while simultaneously allowing uninterrupted coal mining operations. The IM also states that it is the policy of the BLM to encourage oil and gas and coal companies to resolve conflicts between themselves and, when requested, BLM will assist in facilitating agreements between the companies.

- Mining of the North Porcupine LBA tract would not be authorized until: 1) the coal lessee obtains a permit approved by the WDEQ/LQD to mine the tract, and 2) the MLA mining plan is approved by the Secretary of the Interior. Before the MLA mining plan can be approved, BLM must approve a Resource Recovery and Protection Plan (R2P2). Prior to approving the R2P2, BLM can review the status of CBNG and conventional oil and gas development on the tract and the mining sequence proposed by the coal lessee. Because the permit approval process generally takes the coal lessee several years to complete, CBNG resources on the coal tract could continue to be recovered during that time.

- Prior to mining the Federal coal, the coal lessee can negotiate an agreement with the oil, gas, and pipeline owners and operators regarding the removal of their existing facilities on the North Porcupine tract.

Other proposed projects in the Wyoming PRB that have advanced to the planning, permitting, or construction stages and that would reasonably be expected to be completed in the foreseeable future include: the Wygen III coal-fired power plant at the Black Hills Corporation energy complex near the Wyodak Mine site in Gillette, Wyoming (being constructed); the Dry Fork Station coal-fired power plant constructed by Basin Electric Power Cooperative near the Dry Fork Mine north of Gillette (being tested); the Two Elk coal-fired Unit 1 and Unit 2 power plants proposed by the North American Power Group (NAPG) which would be located east of the Black Thunder Mine; and a railroad line from the PRB to Minnesota proposed by the Dakota, Minnesota, and Eastern Railroad Corporation (DM&E). In September, 2007, Canadian Pacific Railway Ltd. announced acquisition of the DM&E and its subsidiaries. The transaction was reviewed and approved by the Surface Transportation Board in October, 2008.

In addition, several coal conversion projects have been proposed. Based on status and available information, only one, the KFx Coal Beneficiation Project, was considered to have a high enough likelihood of proceeding to include it in the PRB Coal Review. The KFx (now Evergreen Energy) coal beneficiation plant produced commercially viable product in 2007 until the plant was idled down in 2008. Since then, Evergreen Energy Inc. and its strategic partner, Bechtel Power Cooperation, decided to relocate operations to a different location.

The proposed power plants, the DM&E railroad line, coal conversion projects, and the ongoing and proposed oil, gas, and CBNG operations are separate projects being developed independently of leasing the North Porcupine tract. If these projects are developed as proposed and the North Porcupine area is leased and mined as proposed, there would potentially be some overlap between the environmental and socioeconomic impacts of constructing and operating some of the projects and the environmental and socioeconomic impacts of mining the North Porcupine tract. The cumulative effects of these projects are described in Chapter 4 of the *Wright Area Coal Lease Applications EIS.* The cumulative impact discussion in the EIS is based on analyses completed for the PRB Coal Review. The PRB Coal Review can be accessed at the following BLM website:
http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/prbdocs.html.

DECISION

As the BLM Wyoming High Plains District Manager, my decision is that it is in the public interest to offer the North Porcupine LBA tract as described below for competitive sale so that these reserves are available to compete for sale in the open coal market to meet the national coal demand that is expected to exist until at least 2035. The public interest is served by leasing the North Porcupine LBA tract because doing so provides a reliable, continuous supply of stable and affordable energy for consumers throughout the country. Developing this coal also helps reduce our nation’s dependence on foreign energy supplies and provides significant socioeconomic benefits for the United States, Wyoming, and local communities.

Under this decision, Alternative 2 for the North Porcupine LBA tract has been selected from the *Wright Area Coal Lease Applications EIS*. Under Alternative 2, the Federal coal included in the North Porcupine LBA tract, as modified by BLM, will be offered for lease at a competitive sealed-bid sale. Under Alternative 2, the North Porcupine tract has been modified by BLM to include additional lands from the BLM study area. The tract includes 6,364.28 acres, more or less, and the BLM estimates that the tract contains approximately 721,154,828 tons of mineable Federal coal resources in Campbell County, Wyoming.

If the highest bid received at the sale meets or exceeds the FMV as determined by the BLM and if all other leasing requirements are met, a lease will be issued to the successful qualified high bidder. The competitive lease sale will be held as described in Federal regulations found at 43 CFR Subpart 3422, Lease Sales. In the event that the highest bid submitted at the competitive lease sale of the North Porcupine LBA tract does not meet or exceed the FMV as determined by BLM, the BLM may, but is not obligated to, re-offer the coal tract for leasing at a later date.

Under Alternative 2, it is assumed that the applicant would be the successful bidder on the North Porcupine LBA tract and that the Federal coal would be mined to extend the life of the adjacent North Antelope Rochelle Mine. The tract would be mined and reclaimed in a logical sequence in concert with ongoing mining and reclamation operations at the adjacent existing mine. This would be consistent with the analysis of the impacts described in the EIS.

This decision incorporates by reference the standard coal lease stipulations which address compliance with the basic requirements of the environmental statutes and additional BLM special stipulations (Appendix 2).

This decision is in conformance with the *Approved Resource Management Plan for Public Lands Administered by the BLM Buffalo Field Office (RMP),* which was completed in 2001 and amended in 2003. This decision is also in conformance with the USDA-FS *Land and Resource Management Plan for the Thunder Basin National Grassland* which was completed in 2001.

For FS-administered lands, consent decision authority has been delegated to the Forest Supervisor level on the Medicine Bow-Routt National Forests and Thunder Basin National Grassland. The North Porcupine LBA tract includes Federal coal lands located within the TBNG administered by FS. Therefore, FS must consent and prescribe terms and conditions in order for the tract to be leased. The FS provided BLM their consent to lease the lands in the North Porcupine LBA tract in the FS Record of Decision signed on September 30, 2011. The FS consent decision is conditioned on application of the Notice for Lands of the National Forest System under Jurisdiction of the Department of Agriculture (FS Notice) on the North Porcupine Federal coal lease tract (WYW173408), when and if the tract is leased (Appendix 2).

REASONS FOR DECISION

Denying this proposed coal leasing is not likely to affect current or future domestic coal consumption used for electric generation. Not offering the North Porcupine Federal coal tract for lease is unlikely to affect changes in the national electric generation portfolio. The rationale for this conclusion is summarized below.

Various commenters on the Wright Area Coal EIS asserted that by not leasing this LBA, and, in a cumulative sense, by denying proposed coal leasing in the Wyoming portion of the PRB, BLM would slow global climate change and would push the national electric generation portfolio to contain only non-carbon fuel alternatives. BLM has thoroughly considered this comment in our decision.

BLM agrees that movement toward electric generation capacity not reliant on carbon fuels is positive. Carbon fuels are a finite resource and will likely become more costly and rare. Having more non-carbon instead of carbon-based electric generation would assist in decreasing human-caused greenhouse gas (GHG) emissions. Reducing human-caused GHG emissions would help to lessen any harmful effects that they may be causing to global climate.

BLM reviewed two independent studies that determined the ability of the domestic electric generation industry to alter the present portfolio (mix of electric generation technologies) corresponding to the time period that the North Porcupine reserves would be leased and produced. The first study was done by the Department of Energy (Annual Energy Outlook 2008 Report, Energy Information Administration, April 2008) and the second was by the domestic electric generation industry's research arm, the Electric Power Research Institute (Electricity Technology in a Carbon Constrained Future, authored by R. James, Carnegie-Mellon University, November 2007).

Both studies projected the electric generation portfolio to 2030 and both studies recognized the likelihood of carbon regulation. While there were differences in each study related to the mix of renewable sources, nuclear, and energy conservation, both studies were consistent in finding that coal-fired electric generation would represent 52-58 percent of the electric generation portfolio by 2030, as compared to the current 51 percent.

The Annual Energy Outlook 2010 Report (Energy Information Administration, December 2009) represents a forecast to the year 2035. This most recent report incorporates the 2009 downturn in electric demand which resulted from lower electric demand for manufacturing in the depressed domestic economy of 2009. This forecast lowered the percentage of coal-fired electric generation in the domestic electric generation portfolio to 44 percent by 2035, based on a slowing in electric demand through 2035, and a doubling, to 17 percent, of renewable electric generation in the domestic electric generation portfolio by 2035.

Based on these studies, even with a considerably more optimistic projection for renewable sources, coal use continues to be projected as the largest portion of the domestic electric fuel mix. As described in the Final EIS, the key determinant of energy consumption is population. As human population and activities have increased over time, coal and other carbon-based fuels have been utilized to provide for these additional energy demands. As directly stated by the Department of Interior Secretary Salazar, “The fact remains that oil and gas and coal are a very important part of our energy portfolio now and they will continue to be an important part of our energy portfolio in the future . . . Fossil fuels and clean technology coal will have to be part of the mix if the U.S. is able to have enough energy in the future" (Great Plains Energy address, November 9, 2009).

Further, BLM disagrees with the comment that denying the proposed Federal coal leasing application would consequentially reduce the overall rate of national coal consumption by electric generators. Numerous mines located outside of the PRB extract and produce coal in the United States. In order to supply reliable power for the country's electrical demands, many mines outside of the PRB have the capacity to replace the coal production generated by the North Antelope Rochelle Mine.

The North Porcupine coal reserves, if leased and approved for mining, would allow the coal mining operator to continue to compete for coal sales in a diverse open supply and demand market. Denying this lease offer would not cease currently approved mining operations. Rather, a denial would require the mine to cease operations only after the current lease reserves were depleted. This would deny the mine operator the ability to compete with other operators in an open market for a future coal demand that is projected to continue until at least 2035. The inability of the North Antelope Rochelle Mine, or any other existing PRB producer, to offer reserves in the coal market would not cause electric generators to stop burning coal. Utility companies will likely operate existing coal-burning facilities until either cost or regulatory requirements render them ineffective or they are replaced by other reliable large scale capacity electric generation technologies capable of consistently supporting the bulk electrical demands of the United States' people.

The effect of rejecting the North Porcupine LBA would be that the existing mine would cease operations after the current reserves are depleted (approximately 9.9 years), and the North Antelope Rochelle Mine would not be competitive in the national coal market to meet the future coal demand in the U.S. that is expected to last until at least 2035. Other national coal producers have the capacity to produce coal and replace the production from this existing mine.

Lastly, PRB coal has competed for an increasing share of coal sales in the market primarily because it is lower cost, environmentally compliant, and successful post-mining reclamation has been thoroughly demonstrated. For these reasons, over the past several decades, PRB coal has been replacing other domestic coals in the open market, and would be expected to compete similarly in the future.

Cumulatively, the effect of rejecting the coal leasing proposed throughout the PRB would be that many of the existing mines would cease operations once current reserves are depleted (ranging from 7 to 15 years). Those mines would then not be able to compete with other mines to meet the future coal demand that is expected to last until at least 2035. When current reserves are depleted at these mines, their production would likely be replaced by other domestic and, potentially, international coal producers with coal that is more costly, less environmentally compliant, and has greater residual environmental impact.

Many other factors including but not limited to those listed below were considered in the decision to lease the North Porcupine LBA tract:

- The Federal Coal Program encourages the development of domestic coal reserves and the reduction of the United States' dependence on foreign sources of energy. BLM recognizes that coal extraction is currently necessary in order to meet the nation's energy needs. A primary goal of the National Energy Policy is to add energy supplies from diverse sources including domestic oil, gas, and coal. Private development of Federal coal reserves is integral to the BLM Coal Leasing Program under the authorities of the Mineral Leasing Act of 1920, the Federal Land Policy and Management Act of 1976 (FLPMA), and the Federal Coal Leasing Amendments Act of 1976 (FCLAA).

- BTU Western Resources, Inc. applied for the North Porcupine LBA coal tract in order to extend the life of the North Antelope Rochelle Mine. The tract, if leased and sold, would allow the mine to acquire access to a continuing supply of low sulfur compliance coal that would be sold to power plants for generating electricity. Continued leasing of low sulfur PRB coal assists coal-fired power plants in meeting the Clean Air Act requirements without constructing new power plants or revamping existing plants. Generally, the expenses associated with constructing new power plants, retrofitting or revamping existing plants, or substituting alternative fuels would increase overall energy costs to customers and consumers.

- The leasing and subsequent mining of Federal coal reserves provides the United States, the State of Wyoming, and its affected counties with income in the form of lease bonus payments, lease royalty payments, and tax payments. Production of Federal coal also provides the public with a supply of cost-efficient, low sulfur coal for power generation. The Governor of Wyoming and other state and local officials support Federal coal leasing.

- The BLM is the lead agency responsible for leasing Federal coal lands under the MLA as amended. When an application to lease Federal coal is submitted, the BLM is obligated to respond to the application in a timely manner. In order to process an LBA, BLM must fulfill the requirements of NEPA by preparing environmental analyses. In this case, an EIS was prepared to provide agency decision-makers and the public with a complete and objective evaluation of the environmental impacts of leasing and mining the Federal coal. BLM then makes a decision on whether or not to offer the Federal coal for lease. In either case, BLM must notify the applicant in a timely fashion of its decision.

- Offering the North Porcupine LBA tract (totaling 6,364.28 acres containing approximately 721,154,828 tons of mineable Federal coal reserves as estimated by the BLM) is responsive to the coal lease application received on September 29, 2006.

- The decision to offer the North Porcupine coal tract for leasing is in conformance with the BLM land use plan decisions covering this area (see section entitled "Conformance with Existing Land Use Plans").

- The *Wright Area Coal Lease Applications EIS* was prepared in response to applications BLM received to lease tracts of Federal coal adjacent to existing mines in Wyoming. The environmental impacts of this decision were fully disclosed in the EIS. Public comments were addressed throughout the NEPA process.

- The BLM's selected tract configuration under Alternative 2, as modified and described in this decision, provides for maximum economic recovery of the coal resource.

- The U.S. Fish and Wildlife Service has provided written concurrence for leasing the North Porcupine coal tract pursuant to Section 7(a)(2) of the Endangered Species Act of 1973, as amended (Appendix 3). Multiple surveys have been conducted for Ute ladies'-tresses during the known flowering periods. Five sage-grouse leks have been documented within two miles of the North Porcupine general analysis area. The Payne Lek, an occupied lek, is located on the North Porcupine tract. The North Porcupine general analysis area is located outside of the Governor of Wyoming's statewide designated greater sage-grouse core area. One prairie dog colony, approximately 18.6 acres in size, is located on the North Porcupine tract. Two golden eagle nests were identified on the North Porcupine tract. Twenty-three bird species on the "Coal Mine List of 40 Migratory Bird Species of Management Concern in Wyoming" have historically been observed at least once in the Wright EIS general analysis area. Wildlife mitigation measures will be prescribed in concert with USFWS during the permit for mining process of the North Porcupine LBA.

- Consultation with the appropriate Native American tribes was initiated by the BLM Wyoming State Office on May 29, 2008. No tribes indicated concerns with the disturbance of cultural sites in the North Porcupine general analysis area.

- Fifty archaeological sites have been identified within the North Porcupine general analysis area. Five sites have previously been determined NRHP eligible (48CA1420/3219, 48CA3218, 48CA3606, 48CA3607, and 48CA3612). The other 45 sites have been determined to be not eligible to the NRHP (48CA262, 48CA498, 48CA1163, 48CA1668, 48CA2108, 48CA2791, 48CA2797, 48CA2800, 48CA2849, 48CA2870, 48CA2891, 48CA2908, 48CA2909, 48CA2910, 48CA2911, 48CA3038, 48CA3039, 48CA3040, 48CA3073, 48CA3074, 48CA3220, 48CA3592, 48CA3593, 48CA3594, 48CA3595, 48CA3596, 48CA3597, 48CA3598, 48CA3599, 48CA3600, 48CA3601, 48CA3602, 48CA3603, 48CA3604, 48CA3605, 48CA3608, 48CA3609, 48CA3610, 48CA3611, 48CA3613, 48CA3614, 48CA3615, 48CA3616, 48CA3617, and 48CA3618).

- The BLM consulted SHPO in relation to determinations of eligibility and impacts for these sites and has determined that leasing the coal would result in an adverse effect to sites 48CA1420/3219, 48CA3218, 48CA3606, 48CA3607, and 48CA3612. However, adverse impacts to 48CA1420/3219, 48CA3218, 48CA3606, 48CA3607, and 48CA3612 have been mitigated by a previously approved adjoining lease action and a land exchange. Therefore, no further consultation or resolution of adverse effects is required. On April

1, 2011, BLM notified SHPO that the undertaking would result in an adverse effect to historic properties. Any further National Historic Preservation Act mitigation consultation with the Wyoming State Historic Preservation Office will be completed as required during the mine permitting process by OSM and WDEQ prior to any surface disturbance of the tract.

- Issuing a Federal coal lease for the North Porcupine tract would not result in the creation of new sources of human-caused GHG or mercury emissions. The North Antelope Rochelle Mine would produce the North Porcupine coal at currently permitted levels using existing production and transportation facilities. If the North Porcupine tract is leased and mined, site-specific GHG emission rates from the North Antelope Rochelle Mine are anticipated to increase slightly compared to current emission rates due to increased strip ratios and added hauling distances.

- If the coal reserves contained within the North Porcupine tract are leased and mined at the currently permitted levels and the coal is used to generate electricity by coal-fired power plants, the emissions of GHG and mercury attributable to the coal produced at the North Antelope Rochelle Mine would be extended for approximately 7.8 years. The rate of human-caused CO_2 and mercury emissions would depend upon the permitted levels at the coal combustion facilities where the coal is burned and the potential emission limits that may be applied to those facilities in the future by regulation or legislation.

- The potential for regulation of GHG emissions as an air pollutant is recognized in this decision. Should such regulation be put in place, there may be an effect on coal demand, depending on how the regulatory actions affect the demand for electric power and the mix of methods used to produce electricity. Effects to coal demand would be reflected through the coal market, coal pricing, and supply. If demand decreases, it is expected that less efficient coal producers, or those with reserves having less desirable coal characteristics, may lose customers. Based on review of past performance, North Antelope Rochelle Mine has competed very well in the national coal market.

PUBLIC INVOLVEMENT

BLM received the Porcupine coal lease application on September 29, 2006. BLM announced the receipt of the LBA and published a Notice of Public Meeting in the Federal Register on December 12, 2006. At the public meeting held in Casper, Wyoming on January 18, 2007, the Powder River Regional Coal Team (PRRCT) reviewed the Porcupine coal lease application and BTU presented information about their existing mine and the pending lease application. The PRRCT recommended that BLM process the application. On March 14, 2007, BLM notified the Governor of Wyoming that BTU had made application for the North and South Porcupine Federal coal lands.

BLM published a Notice of Intent to Prepare an EIS and Notice of Public Meeting in the Federal Register on July 3, 2007, in the Gillette News-Record on July 6, 2007, and in the Douglas Budget on July 11, 2007. Scoping notices were also mailed to Federal, state, and local government agencies, conservation groups, commodity groups, and individuals who could be impacted by this LBA. BLM and the applicant jointly developed the distribution list. On July 24, 2007, a public scoping meeting was held in Gillette, Wyoming. The scoping period extended from July 3 through September 3, 2007, during which time BLM received nine comment letters.

A notice announcing the availability of the *Wright Area Coal Lease Applications Draft EIS* was published in the Federal Register by the EPA on June 26, 2009. Parties on the distribution list were sent copies of the Draft EIS at that time. A 60-day comment period on the Draft EIS commenced with publication of the EPA's Notice of Availability and ended on August 25, 2009. The BLM published a Notice of Availability/Notice of Public Hearing for the Draft EIS in the Federal Register on July 8, 2009. The BLM's Federal Register notice announced the date and time of the formal public hearing, which was held on July 29, 2009, in Gillette, Wyoming. The purpose of the public hearing was to solicit public comment on the Draft EIS, fair market value, maximum economic recovery, and the proposed competitive sale of Federal coal from the Wright Area LBAs. BLM also published a Notice of Public Hearing in both the Douglas Budget and Gillette News-Record newspapers on July 8, 2009. Two individuals presented statements on the Draft EIS during the hearing. BLM received written comments from 17 individuals, agencies, businesses, and organizations as well as over 500 comment e-mails from other interested parties. Comments that BLM received on the Draft EIS and how BLM considered these comments during the preparation of the Final EIS were included in Appendix I of the Final EIS. Written comments and the transcript of the formal public hearing are also available for review at the BLM Wyoming High Plains District Office in Casper.

A notice announcing the availability of the *Wright Area Coal Lease Applications Final EIS* was published in the Federal Register by the EPA on July 30, 2010. Parties on the distribution list were sent copies of the Final EIS at that time. The comment period for the Final EIS ended on August 30, 2010. As explained on the first page of the Final EIS, the public review period was open for 30 days after EPA's Notice of Availability published in the Federal Register.

BLM received written comments on the Final EIS from Michael J. Strawn, Powder River Basin Resource Council/Sierra Club/Center for Biological Diversity, Leslie Glustrom, WildEarth Guardians/Sierra Club/Defenders of Wildlife, Dorsey & Whitney LLP/Ark Land Company, and the Campbell County Board of Commissioners. BLM has reviewed, evaluated, and considered these comments. The comment letters and BLM's responses are available at http://www.blm.gov/wy/st/en/info/NEPA/HighPlains/Wright-Coal.html.

All comments that were received in a timely manner were considered in the preparation of this Record of Decision (ROD).

SUMMARY OF THE PROPOSED ACTION AND ALTERNATIVES

The EIS analyzed the proposed action and two alternatives in detail for the North Porcupine LBA tract. Chapter 2 of the EIS contains a full description of each. Summarized descriptions are presented below.

Proposed Action: <u>Hold a competitive lease sale for the Federal coal lands as applied for and issue a maintenance lease to the successful bidder.</u>

Under the Proposed Action, the as applied for lands in the North Porcupine application as submitted by BTU would have been offered for lease at a competitive sealed-bid sale. As applied for, the tract included approximately 5,795.78 acres (Appendix 1, Figure 2). The applicant estimated that the lands contained approximately 601.2 million tons of recoverable Federal coal. This alternative assumed that the applicant would be the successful bidder and that the coal would be mined, processed, and sold by the North Antelope Rochelle Mine.

Alternative 1 (Environmentally Preferable Alternative): <u>Reject the application.</u>

Under this alternative, BTU's application to lease the Federal coal lands included in the North Porcupine LBA tract would be rejected and the tract would not be offered for competitive sale at this time. This is the No Action Alternative.

The applicant is presently mining existing leases that were previously acquired. Previously approved and permitted mining activity at the adjacent North Antelope Rochelle Mine would continue with or without leasing the North Porcupine LBA tract. Assuming that the North Porcupine LBA tract would never be leased and coal removal and the associated disturbance would never occur, this alternative would be the environmentally preferable alternative. However, selection of this alternative would not preclude future applications to lease all or part of the Federal coal included in the North Porcupine LBA tract.

Rejection of the application would not cause mining operations to immediately cease at the North Antelope Rochelle Mine, nor would it immediately reduce production from this mine. Coal is mined in 27 states and is mostly used for generating electricity to support the country's demand for energy. If the North Porcupine application was rejected and, in the long term, the North Antelope Rochelle Mine was to close, other regional and national mining companies would replace the coal production that would have been lost due to the North Antelope Rochelle Mine's closure.

Alternative 2 (Selected Alternative): <u>Reconfigure the tract and hold one competitive sale for Federal coal lands in the tract as modified by BLM and issue a lease to the successful bidder.</u>

Along with the Federal coal lands that were applied for by BTU, BLM identified and evaluated an additional area comprised of approximately 1,572.01 acres of unleased Federal coal adjacent to the northern and southwestern edges of the application lands (Appendix 1, Figure 2). These additional lands and the as applied for tract were referred to as the BLM study area. The study area enabled BLM to evaluate and explore the potential of increasing competitive interest in the tract, allowing for more efficient recovery of Federal coal in the area, and reducing the likelihood of bypassed Federal coal.

After analyzing the additional lands included in the BLM study area for the North Porcupine, BLM selected the tract configuration as described below. BLM's selected tract configuration includes approximately 1,255.57 acres of additional lands from the BLM study area. The final configuration (Appendix 1, Figure 3) was selected because it allows for more efficient recovery of the Federal coal, may increase competitive interest in the tract, and best serves the public interest. Under the selected configuration, the North Porcupine tract includes approximately 6,364.28 acres and BLM estimates that it contains approximately 721,154,828 tons of mineable Federal coal resources.

The legal description of the lands to be offered for competitive lease sale under Alternative 2, BLM's selected tract configuration, for the North Porcupine tract is as follows:

<u>North Porcupine Tract (WYW173408)</u>:
<u>T.42N., R.70W., 6th P.M., Campbell County, Wyoming</u>

Section 19: Lots 9 through 20;	445.96 acres
Section 20: Lots 5 through 16;	490.93 acres
Section 21: Lots 1 through 16;	660.25 acres
Section 22: Lots 3 through 6, 9 through 16;	491.54 acres
Section 26: Lots 3 through 6, 9 through 16;	496.64 acres
Section 27: Lots 1 through 16;	664.48 acres
Section 28: Lots 1 through 4;	165.98 acres
Section 29: Lots 1 through 4;	164.30 acres
Section 30: Lots 5 through 8;	147.79 acres

<u>T.42N., R.71W., 6th P.M., Campbell County, Wyoming</u>

Section 22: Lots 20, 21, and 24;	12.89 acres
Section 23: Lots 5 through 16;	487.45 acres
Section 24: Lots 5 through 16;	489.12 acres
Section 25: Lots 1 through 4;	162.96 acres
Section 26: Lots 1 through 6, 11 through 14;	404.09 acres
Section 27: Lots 9, 15 through 17, 20, 22, 23, 25, 28, 30;	276.51 acres
Section 34: Lots 1 through 12;	480.20 acres
Section 35: Lots 3 through 6, 11 through 14.	323.19 acres

<u>North Porcupine Tract Total:</u>	<u>6,364.28 acres</u>

The land descriptions and acreages are based on the BLM Status of Public Domain Land and Mineral Titles Approved Master Title Plats as of September 7, 2007 and Coal Plats as of September 20, 2007. The coal estate in the tract described above is Federally-owned. Surface ownership consists of privately owned lands and Federal lands administered by the USDA-Forest Service (FS). The selected configuration for the North Porcupine tract (Appendix 1, Figure 3) includes approximately 5,120 acres, more or less, of National Forest System lands in the Thunder Basin National Grassland (TBNG) administered by the FS.

ALTERNATIVES CONSIDERED BUT NOT ANALYZED IN DETAIL

Further descriptions of these alternatives may be found in Chapter 2 of the Final EIS.

New Mine Start

Under this alternative, as under the Proposed Action, Alternative 1, and Alternative 2, BLM would have held a competitive coal lease sale and issued a lease for the lands included in the North Porcupine tract. This alternative assumed, however, that the successful qualified bidder would have been someone other than the applicant and that this bidder would have planned to open a new mine to develop the Federal coal resources. In BLM's current estimation, for a new mine to open in the Wyoming PRB, the first lease would need to contain approximately 500 to 600 million tons of coal.

This alternative was considered but was not analyzed in detail because it was unlikely that a new mine would start up and lease this tract even though the total amount of coal included in the North Porcupine LBA is sufficient to consider opening a new mine. A new mine start would require considerable initial capital expenses, development of new mining and reclamation plans, and a large number of new employees. A new mine start would also create a new source of air quality impacts. The potential difficulty in obtaining an air quality permit is another issue that could discourage new mine starts in the PRB. In view of these issues, the development of a new mine start on any of the LBA tracts included in the Wright Area EIS is considered unlikely.

Delaying the Sale

Under this alternative, the BLM would have delayed the sale of the North Porcupine tract as applied for. This alternative assumed that the tract could be developed later as either a maintenance tract or a new mine start, depending on how long the sale would have been delayed. The environmental impacts of mining this Federal coal at a later time as a maintenance tract would be expected to be similar to the Proposed Action and Alternative 2. If a new mine start was required to mine the coal in this tract, the environmental impacts would be expected to be greater than if it were mined as an extension of an existing mine.

In general, delaying the sale may have allowed CBNG resources in the Wright general analysis area to be more completely recovered prior to mining. If market prices increased in the future, bonus and royalty payments to the government would have been higher if the tract was offered for sale at a later date.

This alternative was considered but was not analyzed in detail because it would not produce substantially different impacts than other alternatives that were analyzed in detail. First, rental and royalty provisions in the proposed lease provide for the United States to benefit if coal prices increase by the time of mining. Royalty and tax payments are collected at the time the coal is sold. They increase as coal prices increase, which allows the United States to benefit if coal prices have increased by the time of mining. Second, as described in Chapter 2 of the EIS, several mechanisms are already in place to facilitate continued CBNG recovery prior to mining the lands included in the Wright general analysis area.

CONFORMANCE WITH EXISTING LAND USE PLANS

Under the requirements of FCLAA, lands that are being considered for Federal coal leasing must be included in a comprehensive land use plan and leasing decisions must be compatible with that plan. The *Approved Resource Management Plan (RMP) for Public Lands Administered by the Bureau of Land Management Buffalo Field Office,* completed in 2001 and amended in 2003, governs and addresses the leasing of Federal coal in Campbell County. The USDA-FS *Land and Resource Management Plan for the Thunder Basin National Grassland (TBNG), Medicine Bow-Routt National Forest, Rocky Mountain Region*, completed in 2001, guides resource management activities on the TBNG.

The major land use planning decision that BLM must make concerning Federal coal resources is a determination of which Federal coal lands are acceptable for further consideration for leasing. There are four coal screening procedures that BLM uses to identify these coal lands. The screening procedures require BLM to: 1) estimate development potential of the coal lands, 2) apply the unsuitability criteria listed in the regulations at 43 CFR 3461, 3) make multiple land use decisions that eliminate Federal coal deposits from consideration for leasing to protect other resource values, and 4) consult with surface owners who meet the criteria defined in the regulations at 43 CFR 3400.0-5 (gg) (1) and (2). The coal screens were developed for Federal decision-making and are utilized in environmental analyses associated with BLM RMPs, EISs, USDA-FS TBNG planning documents, evaluations, and other resource management activities.

Under the first coal screening procedure, a coal tract must be located within an area that has been determined to have coal development potential in order to receive further consideration for leasing [43 CFR 3420.1-4(e)(1)]. The North Porcupine tract is within the area identified by BLM as having coal development potential.

The second coal screening procedure requires the application of the coal mining unsuitability criteria which are listed in the Federal coal management regulations at 43 CFR 3461. These criteria have been applied to high to moderate coal development potential lands in the Wyoming PRB, including the North Porcupine tract and surrounding lands.

Biological surveys have been conducted throughout the North Porcupine general analysis area. The USFWS has provided written concurrence for leasing the North Porcupine LBA tract pursuant to Section 7(a)(2) of the Endangered Species Act of 1973, as amended (Appendix 3). In coordination with WDEQ, the USFWS will develop and prescribe wildlife mitigation measures as a component of the mining permit authorization process.

A portion of the Burlington Northern Santa Fe & Union Pacific (BNSF & UP) railroad right-of-way (ROW) crosses and borders the west side of the North Porcupine tract. Lands within the rail line right-of-way (ROW) and associated 100-foot buffer zone were found to be unsuitable for mining under Unsuitability Criterion 2. Although the lands within the railroad ROW and buffer zone have been determined to be unsuitable for mining, they are included in the tract lease to allow for efficient recovery of all mineable coal adjacent to and outside of the ROW and its associated buffer zone. This determination also complies with coal leasing regulations which do not allow leasing in less than 10-acre aliquot parts. The lease will include a stipulation stating that no mining activity may be conducted in the portion of the lease within the railroad ROW or associated 100-foot buffer zone. This stipulation honors the finding of unsuitability for mining under Criterion 2.

Unsuitability Criterion Number 3 states that lands within 100 feet of the outside line of the ROW of a public road shall be considered unsuitable for surface coal mining. SMCRA Section 522(e)(4) and 30 CFR 761.11(d) prohibit surface mining operations on lands within 100 feet of the outside line of the ROW for a public road. A portion of the ROW of Antelope Road (Campbell County Road 4), Matheson Road (Campbell County Road 70), and Mackey Road (Campbell County Road 69) are located within BLM's selected configuration for the North Porcupine tract (Appendix 1, Figure 3). BLM has determined that the portion of the North Porcupine tract that includes segments of these three roads, their ROWs, and the 100-foot buffer zones extending on either side of the ROWs must be considered unsuitable for mining at this time under Criterion Number 3.

There is an exception to the public road ROW prohibition in the regulations at SMCRA Section 522(e)(4) and 30 CFR 761.11(d) which can be applied if the appropriate road authority (Campbell County Board of Commissioners) allows the road to be relocated or closed. Surface coal mining could potentially occur within a public road ROW and buffer zone if the regulatory authority, or the appropriate public road authority designated by the regulatory authority, allows the public road to be relocated or closed after providing public notice and opportunity for a public hearing. A finding must be reached, and stated in writing, that the interests of the affected public and landowners will be protected [30 CFR 761.11(d) and 43 CFR 3461.5(c)(iii)].

PRC has obtained approval from the Campbell County Board of Commissioners to close and relocate the portion of Antelope Road that crosses the North Porcupine tract (approximately one mile located in T42N R71W between Section 23 and 24 and between Section 25 and 26). PRC has also consulted the Campbell County Board of Commissioners and other stakeholders for request of approval to close and relocate the Mackey Road in the eastern portion of the North Porcupine tract. The segment of Matheson Road that borders the southern portion of the North Porcupine tract located between T42N R71W Section 35 and T41N R71W Section 2 has been formally vacated by the Campbell County Board of Commissioners.

For public roads granted approval for closure and relocation, the exception to the prohibition on mining within the public road ROW and associated buffer zone could be applied and the unsuitability determination could be reconsidered. A mining company could recover the coal underlying those segments of the public road ROWs and buffer zones that are approved for closure and relocation. If approval is not obtained to relocate or close a public road, the coal underlying the ROW and buffer zone would remain unsuitable for mining and would not be recovered.

Although a portion of the lands within the Antelope Road, Mackey Road, and Matheson Road ROWs and buffer zones have been determined to be unsuitable for mining, they are included in the tract lease to allow for efficient recovery of all mineable coal adjacent to and outside of the ROWs and buffer zones. This determination also complies with coal leasing regulations which do not allow leasing in less than 10-acre aliquot parts. If a lease is issued for this tract, stipulations will be attached stating that no mining activity may be conducted within the public road ROWs and associated buffer zones unless permits to close or relocate the roads are approved by the Campbell County Board of Commissioners. This stipulation honors the finding of unsuitability for mining under Criterion 3.

No other lands included in the North Porcupine tract were found to be unsuitable for mining during the application of the unsuitability criteria for BLM's 2001 Buffalo RMP update. Site-specific unsuitability determinations for some criteria were deferred until an application to lease was filed. These findings are included in Appendix B of the Wright Area Coal Final EIS.

The third coal screening procedure, a multiple land use conflict analysis, must be completed to identify and "eliminate additional coal deposits from further consideration for leasing to protect resource values of a locally important or unique nature not included in the unsuitability criteria," in accordance with 43 CFR 3420.1-4(e)(3). The 2001 Buffalo RMP update addresses two types of multiple land use conflicts: municipal/residential conflicts and multiple mineral development (coal versus oil and gas) conflicts.

The municipal/residential multiple land use conflict was addressed by applying buffers around the municipal planning boundaries for the major municipalities within the BLM Buffalo Field Office area including Gillette and Wright. BLM's selected North Porcupine tract configuration does not extend into any of the municipal buffer zones.

BLM's evaluation of the multiple mineral development conflicts related to issuing a lease for the North Porcupine tract is discussed above in the "Pending Coal Leasing Applications and Other Proposed Projects in the Wyoming Powder River Basin" section of this record of decision.

The fourth coal screening procedure requires consultation with surface owners who meet the criteria defined in the regulations at 43 CFR 3400.0-5(gg)(1) and (2). Under BLM's selected alternative, surface ownership consists of privately owned lands and Federal lands administered by the USDA-FS. Powder River Coal, LLC, School Creek Coal Resources, and Western Railroad Properties, Inc. own the private lands contained within the selected North Porcupine LBA tract. If private surface owners are determined to be qualified under this CFR citation, then qualified surface owner consent is required before those lands can be included in a Federal coal lease. There are no qualified surface owners within the selected configuration for the North Porcupine LBA tract.

In summary, the lands in the North Porcupine coal tract have been subjected to the four coal planning screens and are determined to be acceptable for further consideration for leasing. Thus, a decision to lease the North Porcupine Federal coal lands is in conformance with the current BLM Buffalo RMP and the Thunder Basin National Grassland LRMP.

MITIGATION, COMPLIANCE, AND MONITORING

If the North Porcupine tract is leased, the lease will contain standard coal lease stipulations and also BLM Special Stipulations. BLM has applied special stipulations (Appendix 2) to avoid environmental damage or mitigate potential conflicts affiliated with cultural resources, paleontological resources, threatened and endangered species, multiple mineral development of oil and/or gas and coal resources, resource recovery and protection, and/or public land survey. Special coal lease stipulations were identified in Appendix D of the Final EIS. The final special stipulations are attached (Appendix 2) to this decision and will become part of the Federal coal lease records and pertain to all lands as described in the Federal coal lease tract.

After Federal coal leases are issued, SMCRA gives the OSM authority to administer programs that regulate surface coal mining operations. The WDEQ regulates surface coal mining activities in Wyoming. If BTU is the successful, qualified high bidder for the Federal coal included in the North Porcupine coal tract, a permit revision must then be approved by the WDEQ/LQD. An MLA mining plan revision must also be approved by the Assistant Secretary of the Interior before the coal in the tract could be mined. The existing mitigation measures specific to the currently approved mine plan for the adjacent mine would then be revised to include the new mitigation measures specific to the North Porcupine tract. The mining permit would be amended to include the new mitigation requirements.

If the successful bidder on the North Porcupine coal lease sale does not currently operate a mine that is adjacent to WYW173408, then the bidder would likely propose to construct a new mine in order to recover these Federal coal reserves. Because this would be a new mine start, the proponent would then submit a new permit application package to WDEQ/LQD for approval. A new MLA mining plan would also need to be submitted and approved by the Assistant Secretary of the Interior before the tract could be mined. The approved permit would include mitigation measures and monitoring plans specific to mining the newly leased tract.

Prior to mining a coal lease area, the lease must be permitted for mining by OSM and WDEQ. If a lease is permitted for mining, additional conditions and stipulations may be assigned by OSM and WDEQ. Please see Section 1.3 of the Final EIS for additional information regarding regulatory authority and responsibility in relation to coal mining in Wyoming.

To ensure that the revised plan is in compliance with the leasing stipulations, BLM has a responsibility to review the R2P2 prior to approval of the mining plan. Before any mining operations can begin on the North Porcupine tract (WYW173408), the appropriate R2P2 must be approved by the BLM, a permit or permit revision must be approved by WDEQ/LQD, and an MLA mining plan or plan revision must be approved by the Assistant Secretary of the Interior.

RECOMMENDATION

I recommend that, after a competitive lease sale is held, Federal coal tract WYW173408, with its associated 6,364 acres more or less, be issued to the successful, qualified high bidder, provided it is determined that the highest bid at the sale meets or exceeds the FMV of the tract as determined by the BLM and that all other leasing requirements are met.

This is Alternative 2 for the North Porcupine LBA coal tract, as modified by BLM, and as described in this record of decision. The competitive lease sale will be held in accordance with the requirements at 43 CFR Subpart 3422. The lease will be subject to the attached BLM special lease stipulations (Appendix 2).

Assistant District Manager for Solid Minerals
Wyoming High Plains District Office

10/17/2011
Date

APPROVAL

I agree with the recommendation of the Assistant District Manager for Solid Minerals, and I approve the decision to offer Federal coal tract WYW173408 for competitive lease sale.

Stephanie Connolly
BLM Wyoming High Plains District Manager

10/17/2011
Date

APPEAL OF DISTRICT MANAGER DECISION

This decision may be appealed to the Interior Board of Land Appeals, Office of the Secretary, in accordance with the regulations contained in 43 CFR Subpart 4 and the enclosed form 1842-1 (Appendix 4). If an appeal is filed, your notice of appeal must be filed in this office (BLM Wyoming High Plains District Office, 2987 Prospector Drive, Casper, WY 82604) within thirty (30) days from the date BLM published the Notice of Availability (NOA) of this Record of Decision in the Federal Register. The appellant has the burden of showing that the decision appealed is in error.

If you wish to file a petition (request) pursuant to regulations 43 CFR 4.21(a)(2) for a stay (suspension) of the effectiveness of this decision during the time that your appeal is being reviewed by the board, the petition for a stay must accompany your notice of appeal. A petition for a stay is required to show sufficient justification based on the standards listed below. Copies of the notice of appeal and petition for a stay must also be submitted to each party named in this decision and to the Interior Board of Land Appeals and to the appropriate Office of the Solicitor (see 43 CFR 4.413) at the same time the original documents are filed with this office. If you request a stay, you have the burden of proof to demonstrate that a stay should be granted.

Standard for Obtaining a Stay

Except as otherwise provided by law or other pertinent regulations, a petition for a stay of a decision pending appeal shall show sufficient justification based on the following standards:

1) The relative harm to the parties if a stay is granted or denied;
2) The likelihood of the appellant's success on the merits;
3) The likelihood of the immediate and irreparable harm if the stay is not granted; and,
4) Whether the public interest favors granting a stay.

Appendix 1. Figures 1, 2, and 3

Appendix 2. BLM Special Coal Lease Stipulations (WYW173408), Notice for Lands of the National Forest System under Jurisdiction of the Department of Agriculture (WYW173408), and BLM Coal Lease Form 3400-12

Appendix 3. U.S. Fish and Wildlife Service Concurrence Letter

Appendix 4. Appeal Procedures

APPENDIX 1

FIGURES

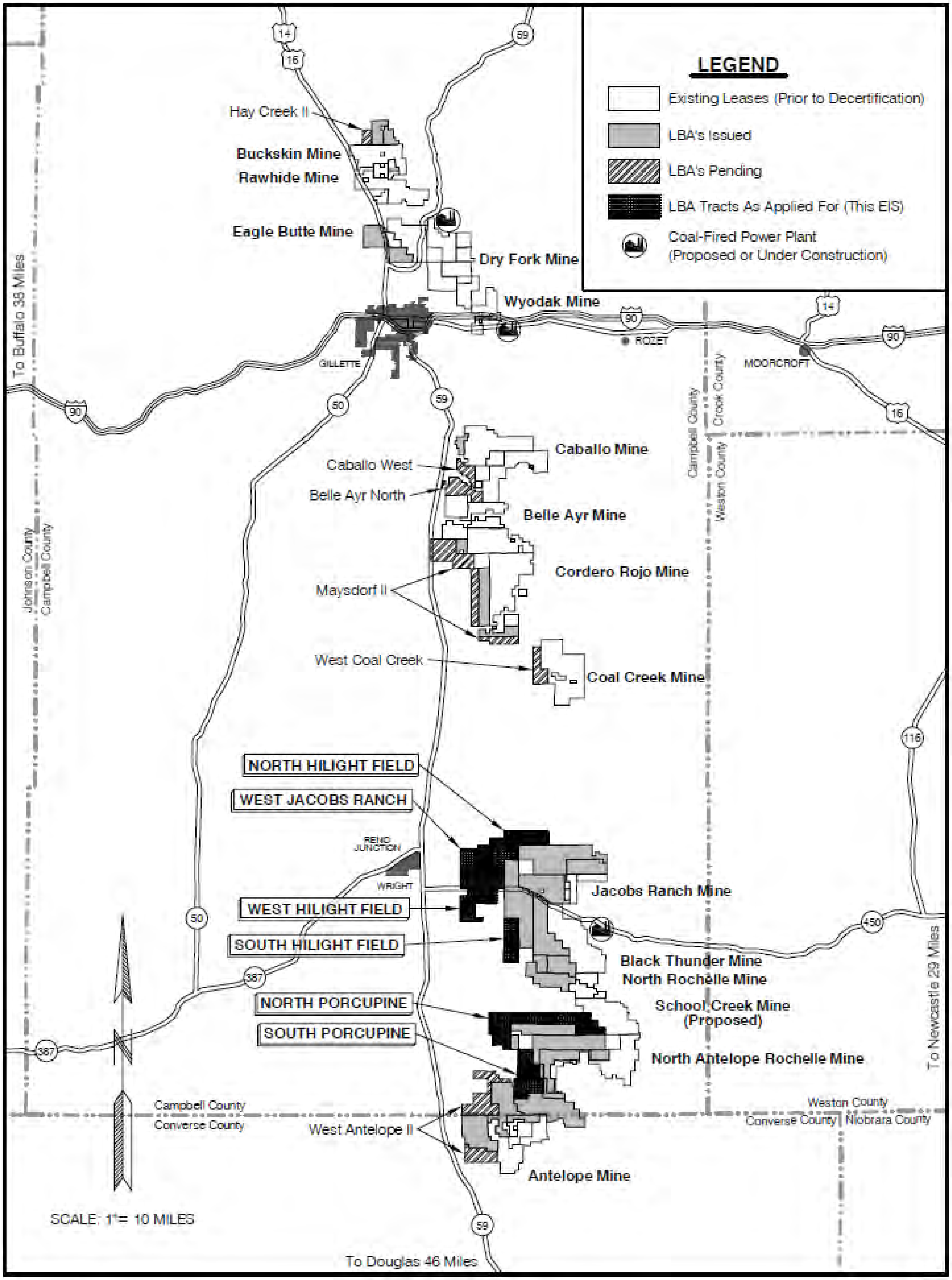


Figure 1. General Location Map with Federal Coal Leases and LBA Tracts

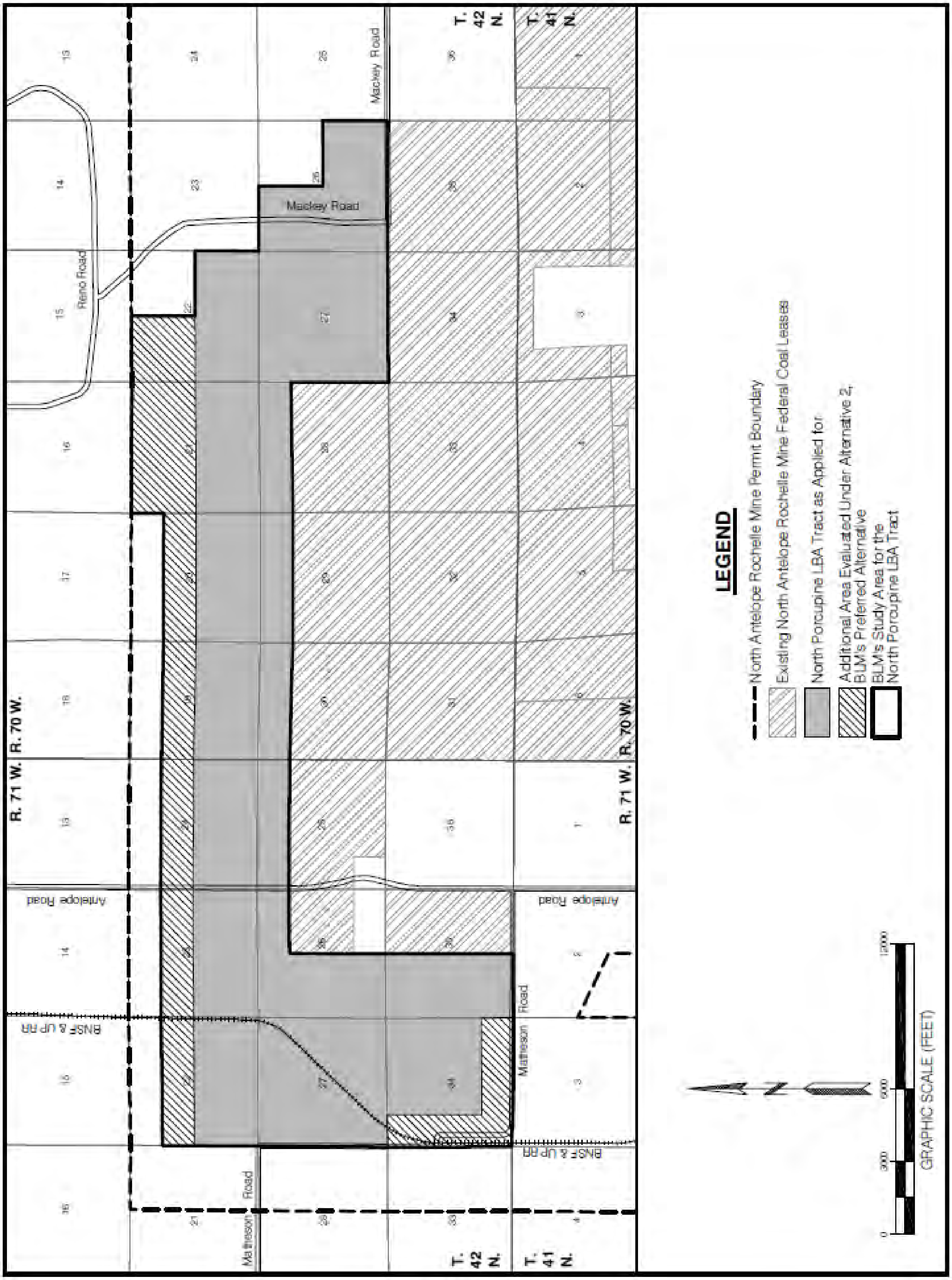


Figure 2. North Porcupine LBA Tract Alternatives

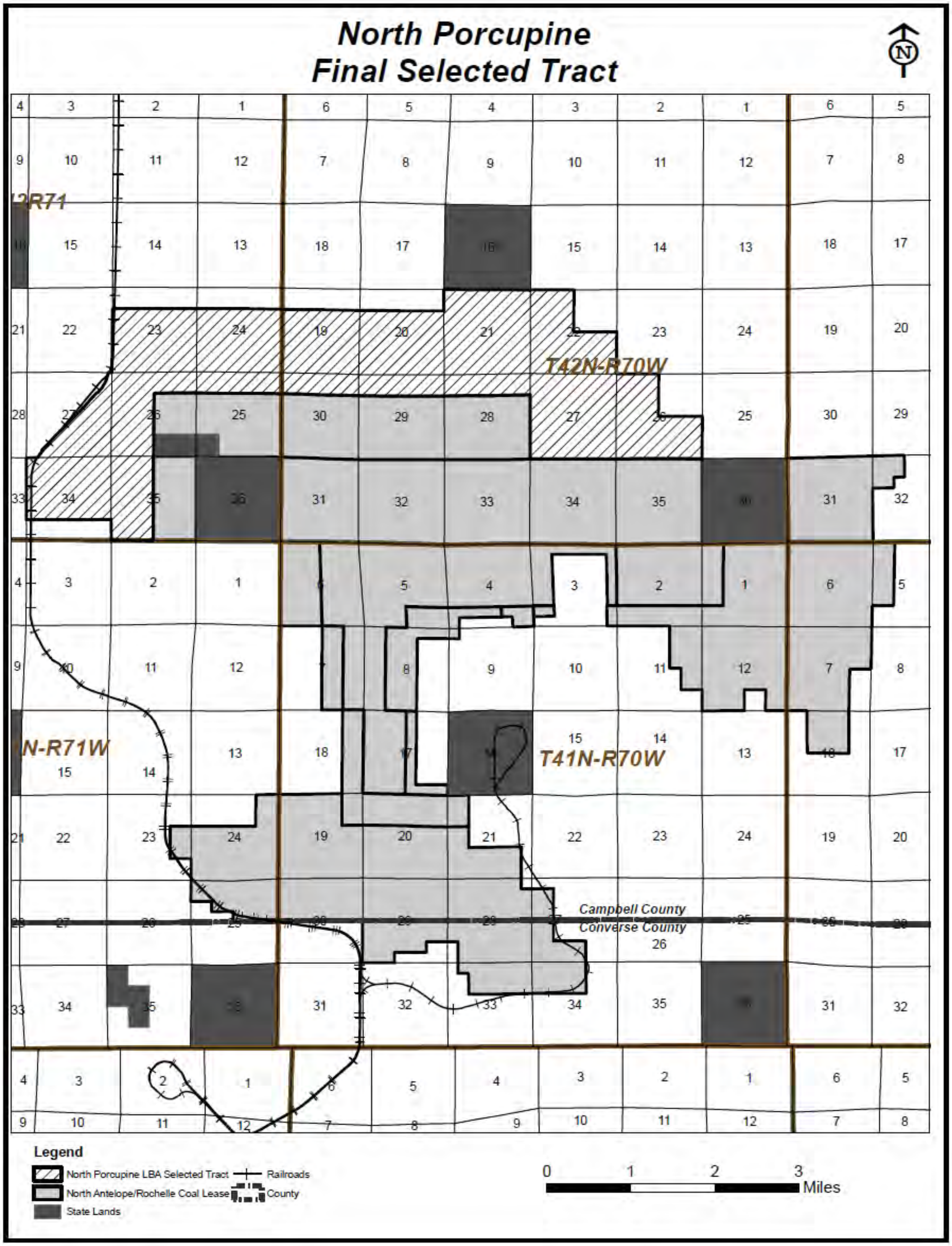


Figure 3. North Porcupine Tract Selected Configuration

APPENDIX 2

BLM SPECIAL COAL LEASE STIPULATIONS,

NOTICE FOR LANDS OF THE
NATIONAL FOREST SYSTEM UNDER JURISDICTION
OF THE DEPARTMENT OF AGRICULTURE,

AND BLM COAL LEASE FORM 3400-12

SPECIAL STIPULATIONS FOR THE
NORTH PORCUPINE LBA COAL TRACT:
WYW173408

In addition to observing the general obligations and standards of performance set out in the current regulations, the lessee shall comply with and be bound by the following special stipulations.

These stipulations are also imposed upon the lessee's agents and employees. The failure or refusal of any of these persons to comply with these stipulations shall be deemed a failure of the lessee to comply with the terms of the lease. The lessee shall require his agents, contractors, and subcontractors involved in activities concerning this lease to include these stipulations in the contracts between and among them. These stipulations may be revised or amended, in writing, by the mutual consent of the lessor and the lessee at any time to adjust to changed conditions or to correct an oversight.

(a) ***CULTURAL RESOURCES***

(1) Before undertaking any activities that may disturb the surface of the leased lands, the lessee shall conduct a cultural resource intensive field inventory in a manner specified by the Authorized Officer of the BLM or of the surface managing agency, if different, on portions of the mine plan area and adjacent areas, or exploration plan area, that may be adversely affected by lease-related activities and which were not previously inventoried at such a level of intensity. The inventory shall be conducted by a qualified professional cultural resource specialist (i.e., archeologist, historian, historical architect, as appropriate), approved by the Authorized Officer of the surface managing agency (BLM, if the surface is privately owned), and a report of the inventory and recommendations for protecting any cultural resources identified shall be submitted to the Regional Director of the Western Region of the Office of Surface Mining (the Western Regional Director), the Authorized Officer of the BLM, if activities are associated with coal exploration outside an approved mining permit area (hereinafter called Authorized Officer), and the Authorized Officer of the surface managing agency, if different. The lessee shall undertake measures, in accordance with instructions from the Western Regional Director, or Authorized Officer, to protect cultural resources on the leased lands. The lessee shall not commence the surface disturbing activities until permission to proceed is given by the Western Regional Director or Authorized Officer.

2) Any existing Class III inventory report covering the lease area that has not received federal agency review must be reviewed and accepted by the agency, site NRHP eligibility determinations made, and consultation with the State Historic Preservation Officer completed before any surface disturbing activities take place.

(3) The lessee shall protect all cultural resource properties that have been determined eligible or unevaluated to the National Register of Historic Places within the lease area from lease-related activities until the cultural resource mitigation measures or site evaluations can be implemented as part of an approved mining and reclamation or exploration plan unless modified by mutual agreement in consultation with the State Historic Preservation Officer.

(4) The cost of conducting the inventory, preparing reports, and carrying out mitigation measures shall be borne by the lessee.

(5) If cultural resources are discovered during operations under this lease, the lessee shall immediately bring them to the attention of the Western Regional Director or Authorized Officer, or the Authorized Officer of the surface managing agency if the Western Regional Director is not available. The lessee shall not disturb such resources except as may be subsequently authorized by the Western Regional Director or Authorized Officer. Within two (2) working days of notification, the Western Regional Director or Authorized Officer will evaluate or have evaluated any cultural resources discovered and will determine if any action may be required to protect or preserve such discoveries. The cost of data recovery for cultural resources discovered during lease operations shall be borne by the lessee unless otherwise specified by the Authorized Officer of the BLM or of the surface managing agency, if different.

(6) All cultural resources shall remain under the jurisdiction of the United States until ownership is determined under applicable law.

(b) ***PALEONTOLOGICAL RESOURCES***

If paleontological resources, either large and conspicuous, and/or of significant scientific value, are discovered during mining operations, the find will be reported to the Authorized Officer immediately. Mining operations will be suspended within 250 feet of said find. An evaluation of the paleontological discovery will be made by a BLM-approved professional paleontologist within five (5) working days, weather permitting, to determine the appropriate action(s) to prevent the potential loss of any significant paleontological value. Operations within 250 feet of such discovery will not be resumed until written authorization to proceed is issued by the Authorized Officer. The lessee will bear the cost of any required paleontological appraisals, surface collection of fossils, or salvage of any large conspicuous fossils of significant scientific interest discovered during the operations.

(c) ***THREATENED, ENDANGERED, CANDIDATE, OR OTHER SPECIAL STATUS PLANT AND ANIMAL SPECIES***

(1) The lease area may now or hereafter contain plants, animals, or their habitats determined to be threatened or endangered under the Endangered Species Act of 1973, as amended, 16 U.S.C. 1531 *et seq*., or that have other special status. The Authorized Officer may recommend modifications to exploration and development proposals to further conservation and management objectives or to avoid activity that will contribute to a need to list such species or their habitat or to comply with any biological opinion issued by the U.S. Fish and Wildlife Service for the Proposed Action. The Authorized Officer 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. The Authorized Officer may require modifications to, or disapprove a 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 designated or proposed critical habitat.

(2) The lessee shall comply with instructions from the Authorized Officer of the surface managing agency (BLM, if the surface is private) for ground disturbing activities associated with coal exploration on federal coal leases prior to approval of a mining and reclamation permit or outside an approved mining and reclamation permit area. The lessee shall comply with instructions from the Authorized Officer of the Office of Surface Mining Reclamation and Enforcement, or his designated representative, for all ground disturbing activities taking place within an approved mining and reclamation permit area or associated with such a permit.

(3) Any potential habitat that has not already been surveyed for Ute ladies'-tresses within the project area shall be identified and surveyed prior to surface mining activities.

(d) ***MULTIPLE MINERAL DEVELOPMENT***

Operations will not be approved which, in the opinion of the Authorized Officer, would unreasonably interfere with the orderly development and/or production from a valid existing mineral lease issued prior to this one for the same lands.

(e) ***OIL AND GAS/COAL RESOURCES***

The BLM realizes that coal mining operations conducted on Federal coal leases issued within producing oil and gas fields may interfere with the economic recovery of oil and gas, just as Federal oil and gas leases issued in a Federal coal lease area may inhibit coal recovery. BLM retains the authority to alter and/or modify the resource recovery and protection plans for coal operations and/or oil and gas operations on those lands covered by Federal mineral leases so as to obtain maximum resource recovery.

(f) ***RESOURCE RECOVERY AND PROTECTION***

Notwithstanding the approval of a resource recovery and protection plan (R2P2) by the BLM, the lessor reserves the right to seek damages against the operator/lessee in the event (i) the operator/lessee fails to achieve maximum economic recovery (MER) (as defined at 43 CFR 3480.0-5(21)) of the recoverable coal reserves or (ii) the operator/lessee is determined to have caused a wasting of recoverable coal reserves. Damages shall be measured on the basis of the royalty that would have been payable on the wasted or unrecovered coal.

The parties recognize that under an approved R2P2, conditions may require a modification by the operator/lessee of that plan. In the event a coal bed or portion thereof is not to be mined or is rendered unmineable by the operation, the operator/lessee shall submit appropriate justification to obtain approval by the Authorized Officer to leave such reserves unmined. Upon approval by the Authorized Officer, such coal beds or portions thereof shall not be subject to damages as described above. Further, nothing in this section shall prevent the operator/lessee from exercising its right to relinquish all or a portion of the lease as authorized by statute and regulation.

In the event the Authorized Officer determines that the R2P2, as approved, will not attain MER as the result of changed conditions, the Authorized Officer will give proper notice to the operator/lessee as required under applicable regulations. The Authorized Officer will order a modification if necessary, identifying additional reserves to be mined in order to attain MER. Upon a final administrative or judicial ruling upholding such an ordered modification, any reserves left unmined (wasted) under that plan will be subject to damages as described in the first paragraph under this section.

Subject to the right to appeal hereinafter set forth, payment of the value of the royalty on such unmined recoverable coal reserves shall become due and payable upon determination by the Authorized Officer that the coal reserves have been rendered unmineable or at such time that the operator/lessee has demonstrated an unwillingness to extract the coal.

The BLM may enforce this provision either by issuing a written decision requiring payment of the Office of Natural Resources Revenue (formerly known as Mineral Management Service) demand for such royalties, or by issuing a notice of non-compliance. A decision or notice of non-compliance issued by the lessor that payment is due under this stipulation is appealable as allowed by law.

(g) ***PUBLIC LAND SURVEY PROTECTION***

The lessee will protect all survey monuments, witness corners, reference monuments, and bearing trees against destruction, obliteration, or damage during operations on the lease areas. If any monuments, corners or accessories are destroyed, obliterated, or damaged by this operation, the lessee will hire an appropriate county surveyor or registered land surveyor to reestablish or restore the monuments, corners, or accessories at the same location, using surveying procedures in accordance with the "Manual of Surveying Instructions for the Survey of the Public Lands of the United States." The survey will be recorded in the appropriate county records, with a copy sent to the Authorized Officer.

ADDITIONAL SPECIAL STIPULATIONS FOR THE NORTH PORCUPINE COAL TRACT (WYW173408)

(h) ***PUBLIC ROAD RIGHT-OF-WAY AND BUFFER ZONE***

No mining activity of any kind may be conducted within the Antelope Road (Campbell County Road 4), Mackey Road, or Matheson Road rights-of-way and associated 100-foot buffer zones while these public roads remain in their current (2009) locations. The lessee shall recover all legally and economically recoverable coal from all leased lands not within the foregoing rights-of-way and associated buffer zones. If permits are obtained to relocate these roads and are approved by the appropriate authority, the lessee shall recover all legally and economically recoverable coal from all leased lands within the foregoing rights-of-way and associated buffer zone. The lessee shall pay all royalties on any legally and economically recoverable coal which it fails to mine without the written permission of the Authorized Officer.

(i) ***RAILROAD RIGHT-OF-WAY AND BUFFER ZONE***

No mining activity of any kind may be conducted within the Burlington Northern Santa Fe & Union Pacific railroad right-of-way and associated 100-foot buffer zone. The lessee shall recover all legally and economically recoverable coal from all leased lands not within the foregoing right-of-way. The lessee shall pay all royalties on any legally and economically recoverable coal which it fails to mine without the written permission of the Authorized Officer.

NOTICE FOR LANDS OF THE NATIONAL FOREST SYSTEM UNDER JURISDICTION OF DEPARTMENT OF AGRICULTURE

R2-FS-2820-13 (92) Serial No. WYW173408

The permittee/lessee must comply with all the rules and regulations of the Secretary of Agriculture set forth at Title 36, Chapter II, of the Code of Federal Regulations governing the use and management of the National Forest System (NFS) when not inconsistent with the rights granted by the Secretary of Interior in the permit. The Secretary of Agriculture's rules and regulations must be complied with for (1) all use and occupancy of the NFS prior to approval of an exploration plan by the Secretary of the Interior, (2) uses of all existing improvements, such as forest development roads, within and outside the area permitted by the Secretary of the Interior, and (3) use and occupancy of the NFS not authorized by an exploration plan approved by the Secretary of the Interior.

All matters related to this stipulation are to be addressed to:

Forest Supervisor
Medicine Bow-Routt National Forests & Thunder Basin National Grassland
2468 Jackson Street
Laramie, WY 82070
307-745-2300

who is the authorized representative of the Secretary of Agriculture.

NOTICE

CULTURAL AND PALEONTOLOGICAL RESOURCES - The FS is responsible for assuring that the leased lands are examined to determine if cultural resources are present and to specify mitigation measures. Prior to undertaking any surface-disturbing activities on the lands covered by this lease, the lessee or operator, unless notified to the contrary by the FS, shall:

1. Contact the FS to determine if a site specific cultural resource inventory is required. If a survey is required, then:

2. Engage the services of a cultural resource specialist acceptable to the FS to conduct a cultural resource inventory of the area of proposed surface disturbance. The operator may elect to inventory an area larger than the area of proposed disturbance to cover possible site relocation which may result from environmental or other considerations. An acceptable inventory report is to be submitted to the FS for review and approval at the time a surface disturbing plan of operation is submitted.

3. Implement mitigation measures required by the FS and BLM to preserve or avoid destruction of cultural resource values. Mitigation may include relocation of proposed facilities, testing, salvage, and recordation or other protective measures. All costs of the inventory and mitigation will be borne by the lessee or operator, and all data and materials salvaged will remain under the jurisdiction of the U.S. Government as appropriate.

The lessee or operator shall immediately bring to the attention of the FS and BLM any cultural or paleontological resources or any other objects of scientific interest discovered as a result of surface operations under this lease, and shall leave such discoveries intact until directed to proceed by FS and BLM.

ENDANGERED OR THREATENED SPECIES - The FS is responsible for assuring that the leased land is examined prior to undertaking any surface-disturbing activities to determine effects upon any plant or animal species listed or proposed for listing as endangered or threatened, or their habitats. The findings of this examination may result in some restrictions to the operator's plans or even disallow use and occupancy that would be in violation of the Endangered Species Act of 1973 by detrimentally affecting endangered or threatened species or their habitats.

The lessee/operator may, unless notified by the FS that the examination is not necessary, conduct the examination on the leased lands at his discretion and cost. This examination must be done by or under the supervision of a qualified resource specialist approved by the FS. An acceptable report must be provided to the FS identifying the anticipated effects of a proposed action on endangered or threatened species or their habitats.

____

Signature of Licensee/Permittee/Lessee

Form 3400-12
(September 2010)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

COAL LEASE

FORM APPROVED
OMB NO. 1004-0073
Expires: June 30, 2013

Serial Number

PART 1. LEASE RIGHTS GRANTED

This lease, entered into by and between the UNITED STATES OF AMERICA, hereinafter called lessor, through the Bureau of Land Management (BLM), and *(Name and Address)*

hereinafter called lessee, is effective *(date)* / / , for a period of 20 years and for so long thereafter as coal is produced in commercial quantities from the leased lands, subject to readjustment of lease terms at the end of the 20th lease year and each 10-year period thereafter.

Sec. 1.This lease is issued pursuant and subject to the terms and provisions of the:

☐ The Mineral Leasing Act of 1920, as amended, 30 U.S.C. 181 - 287; or
☐ The Mineral Leasing Act for Acquired Lands, 30 U.S.C. 351 - 359;
and to the regulations and formal orders of the Secretary of the Interior which are now or hereafter in force, when not inconsistent with the express and specific provisions herein.

Sec. 2. Lessor, in consideration of any bonuses, rents, and royalties to be paid, and the conditions and covenants to be observed as herein set forth, hereby grants and leases to lessee the exclusive right and privilege to drill for, mine, extract, remove, or otherwise process and dispose of the coal deposits in, upon, or under the following described lands:

containing acres, more or less, together with the right to construct such works, buildings, plants, structures, equipment and appliances and the right to use such on-lease rights-of-way which may be necessary and convenient in the exercise of the rights and privileges granted, subject to the conditions herein provided.

PART II. TERMS AND CONDITIONS

Sec. 1. (a) RENTAL RATE - Lessee must pay lessor rental annually and in advance for each acre or fraction thereof during the continuance of the lease at the rate of $ for each lease year.

(b) RENTAL CREDITS - Rental will not be credited against either production or advance royalties for any year.

Sec. 2. (a) PRODUCTION ROYALTIES - The royalty will be percent of the value of the coal as set forth in the regulations. Royalties are due to lessor the final day of the month succeeding the calendar month in which the royalty obligation accrues.

(b) ADVANCE ROYALTIES - Upon request by the lessee, the BLM may accept, for a total of not more than 20 years, the payment of advance royalties in lieu of continued operation, consistent with the regulations. The advance royalty will be based on a percent of the value of a minimum number of tons determined in the manner established by the advance royalty regulations in effect at the time the lessee requests approval to pay advance royalties in lieu of continued operation.

Sec. 3. BONDS - Lessee must maintain in the proper office a lease bond in the amount of $. The BLM may require an increase in this amount when additional coverage is determined appropriate.

Sec. 4. DILIGENCE - This lease is subject to the conditions of diligent development and continued operation, except that these conditions are excused when operations under the lease are interrupted by strikes, the elements, or casualties not attributable to the lessee. The lessor, in the public interest, may suspend the condition of continued operation upon payment of advance royalties in accordance with the regulations in existence at the time of the suspension. Lessee's failure to produce coal in commercial quantities at the end of 10 years will terminate the lease. Lessee must submit an operation and reclamation plan for the BLM's approval pursuant to 30 U.S.C. 207(c) prior to conducting any development or mining operations or taking any other action on a leasehold which might cause a significant disturbance of the environment.

The lessor reserves the power to assent to or order the suspension of the terms and conditions of this lease in accordance with, inter alia, Section 39 of the Mineral Leasing Act, 30 U.S.C. 209.

5. LOGICAL MINING UNIT (LMU) - Either upon approval by the lessor of the lessee's application or at the direction of the lessor, this lease will become an LMU or part of an LMU, subject to the provisions set forth in the regulations.

The stipulations established in an LMU approval in effect at the time of LMU approval will supersede the relevant inconsistent terms of this lease so long as the lease remains committed to the LMU. If the LMU of which this lease is a part is dissolved, the lease will then be subject to the lease terms which would have been applied if the lease had not been included in an LMU.

(Continued on page 2)

Sec. 6. DOCUMENTS, EVIDENCE AND INSPECTION - At such times and in such form as lessor may prescribe, lessee must furnish detailed statements showing the amounts and quality of all products removed and sold from the lease, the proceeds therefrom, and the amount used for production purposes or unavoidably lost.

Lessee must keep open at all reasonable times for the inspection by BLM the leased premises and all surface and underground improvements, works, machinery, ore stockpiles, equipment, and all books, accounts, maps, and records relative to operations, surveys, or investigations on or under the leased lands.

Lessee must allow lessor access to and copying of documents reasonably necessary to verify lessee compliance with terms and conditions of the lease.

While this lease remains in effect, information obtained under this section will be closed to inspection by the public in accordance with the Freedom of Information Act (5 U.S.C. 552).

Sec. 7. DAMAGES TO PROPERTY AND CONDUCT OF OPERATIONS - Lessee must comply at its own expense with all reasonable orders of the Secretary, respecting diligent operations, prevention of waste, and protection of other resources.

Lessee must not conduct exploration operations, other than casual use, without an approved exploration plan. All exploration plans prior to the commencement of mining operations within an approved mining permit area must be submitted to the BLM.

Lessee must carry on all operations in accordance with approved methods and practices as provided in the operating regulations, having due regard for the prevention of injury to life, health, or property, and prevention of waste, damage or degradation to any land, air, water, cultural, biological, visual, and other resources, including mineral deposits and formations of mineral deposits not leased hereunder, and to other land uses or users. Lessee must take measures deemed necessary by lessor to accomplish the intent of this lease term. Such measures may include, but are not limited to, modification to proposed siting or design of facilities, timing of operations, and specification of interim and final reclamation procedures. Lessor reserves to itself the right to lease, sell, or otherwise dispose of the surface or other mineral deposits in the lands and the right to continue existing uses and to authorize future uses upon or in the leased lands, including issuing leases for mineral deposits not covered hereunder and approving easements or rights-of-way. Lessor must condition such uses to prevent unnecessary or unreasonable interference with rights of lessee as may be consistent with concepts of multiple use and multiple mineral development.

Sec. 8. PROTECTION OF DIVERSE INTERESTS, AND EQUAL OPPORTUNITY - Lessee must: pay when due all taxes legally assessed and levied under the laws of the State or the United States; accord all employees complete freedom of purchase; pay all wages at least twice each month in lawful money of the United States; maintain a safe working environment in accordance with standard industry practices; restrict the workday to not more than 8 hours in any one day for underground workers, except in emergencies; and take measures necessary to protect the health and safety of the public. No person under the age of 16 years should be employed in any mine below the surface. To the extent that laws of the State in which the lands are situated are more restrictive than the provisions in this paragraph, then the State laws apply.

Lessee will comply with all provisions of Executive Order No. 11246 of September 24, 1965, as amended, and the rules, regulations, and relevant orders of the Secretary of Labor. Neither lessee nor lessee's subcontractors should maintain segregated facilities.

Sec. 9. (a) TRANSFERS -

This lease may be transferred in whole or in part to any person, association or corporation qualified to hold such lease interest.

This lease may be transferred in whole or in part to another public body or to a person who will mine coal on behalf of, and for the use of, the public body or to a person who for the limited purpose of creating a security interest in favor of a lender agrees to be obligated to mine the coal on behalf of the public body.

This lease may only be transferred in whole or in part to another small business qualified under 13 CFR 121.

Transfers of record title, working or royalty interest must be approved in accordance with the regulations.

(b) RELINQUISHMENT - The lessee may relinquish in writing at any time all rights under this lease or any portion thereof as provided in the regulations. Upon lessor's acceptance of the relinquishment, lessee will be relieved of all future obligations under the lease or the relinquished portion thereof, whichever is applicable.

Sec. 10. DELIVERY OF PREMISES, REMOVAL OF MACHINERY, EQUIPMENT, ETC. - At such time as all portions of this lease are returned to lessor, lessee must deliver up to lessor the land leased, underground timbering, and such other supports and structures necessary for the preservation of the mine workings on the leased premises or deposits and place all workings in condition for suspension or abandonment. Within 180 days thereof, lessee must remove from the premises all other structures, machinery, equipment, tools, and materials that it elects to or as required by the BLM. Any such structures, machinery, equipment, tools, and materials remaining on the leased lands beyond 180 days, or approved extension thereof, will become the property of the lessor, but lessee may either remove any or all such property or continue to be liable for the cost of removal and disposal in the amount actually incurred by the lessor. If the surface is owned by third parties, lessor will waive the requirement for removal, provided the third parties do not object to such waiver. Lessee must, prior to the termination of bond liability or at any other time when required and in accordance with all applicable laws and regulations, reclaim all lands the surface of which has been disturbed, dispose of all debris or solid waste, repair the offsite and onsite damage caused by lessee's activity or activities incidental thereto, and reclaim access roads or trails.

Sec. 11. PROCEEDINGS IN CASE OF DEFAULT - If lessee fails to comply with applicable laws, existing regulations, or the terms, conditions and stipulations of this lease, and the noncompliance continues for 30 days after written notice thereof, this lease will be subject to cancellation by the lessor only by judicial proceedings. This provision will not be construed to prevent the exercise by lessor of any other legal and equitable remedy, including waiver of the default. Any such remedy or waiver will not prevent later cancellation for the same default occurring at any other time.

Sec. 12. HEIRS AND SUCCESSORS-IN-INTEREST - Each obligation of this lease will extend to and be binding upon, and every benefit hereof will inure to, the heirs, executors, administrators, successors, or assigns of the respective parties hereto.

Sec. 13. INDEMNIFICATION - Lessee must indemnify and hold harmless the United States from any and all claims arising out of the lessee's activities and operations under this lease.

Sec. 14. SPECIAL STATUTES - This lease is subject to the Clean Water Act (33 U.S.C. 1252 et seq.), the Clean Air Act (42 U.S.C. 4274 et seq.), and to all other applicable laws pertaining to exploration activities, mining operations and reclamation, including the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C. 1201 et seq.).

Sec. 15. SPECIAL STIPULATIONS -

(Continued on page 3)

Sec. 15. SPECIAL STIPULATIONS (Cont'd.) -

THE UNITED STATES OF AMERICA

(Company or Lessee Name)	By
(Signature of Lessee)	(BLM)
(Title)	(Title)
(Date)	(Date)

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Continued on page 4)

NOTICES

The Privacy Act and 43 CFR 2.48(d) require that you be furnished with the following information in connection with the information requested by this form.
AUTHORITY: 30 U.S.C. 181 - 287 and 30 U.S.C. 351 - 359 permit collection of the information requested by this form.
PRINCIPAL PURPOSE: The BLM will use the information you provide to process your application and determine if you are eligible to hold a coal lease on public lands.
ROUTINE USES: The BLM will only disclose this information in accordance with the provisions at 43 CFR 2.56(b) and (c).
EFFECT OF NOT PROVIDING INFORMATION: Submission of the requested information is necessary to obtain or retain a benefit. Failure to submit all of the requested information or to complete this form may result in delay or preclude the BLM's acceptance of your application for a coal lease.

The Paperwork Reduction Act requires us to inform you that:
The BLM collects this information to evaluate and authorize proposed exploration and mining operations on public lands.
Submission of the requested information is necessary to obtain or retain a benefit.
You do not have to respond to this or any other Federal agency-sponsored information collection unless it displays a currently valid OMB control number.

BURDEN HOURS STATEMENT: The public reporting burden for this form is estimated to average 25 hours per response when the form is used under the authority of 43 subpart 3422 (Lease Sales), or 800 hours per response when the form is used under the authority of 43 subpart 3430 (Preference Right Leases). The estimated burdens include the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. You may submit comments regarding the burden estimate or any other aspect of this form to: U.S. Department of the Interior, Bureau of Land Management (1004-0073), Bureau Information Collection Clearance Officer (WO-630), 1849 C Street, Mail Stop 401 LS, Washington, DC 20240.

APPENDIX 3

U.S. FISH AND WILDLIFE SERVICE
CONCURRENCE LETTER

United States Department of the Interior

FISH AND WILDLIFE SERVICE

Ecological Services
5353 Yellowstone Road, Suite 308A
Cheyenne, Wyoming 82009

In Reply Refer To:
ES-61411/WY11I0131/WY11CPA0109

MAR 0 3 2011

Memorandum

To: District Manager, Solid Minerals, Bureau of Land Management, Wyoming High Plains District, Casper, Wyoming

From: Field Supervisor, U.S. Fish and Wildlife Service, Wyoming Field Office, Cheyenne, Wyoming

Subject: Concurrence for the North Porcupine and South Porcupine Coal Lease-By-Application Tracts

Thank you for your letter dated February 8, 2011, received in our office on February 11, and attached biological assessment for the North Porcupine and South Porcupine Coal Lease-By-Application (LBA) Tracts. Under the Bureau of Land Management's (Bureau) preferred alternative (Alternative 2) in the Wright Area Coal Lease Applications Final Environmental Impact Statement for the North Porcupine and South Porcupine LBA Tracts (FEIS), the Bureau will hold a sealed-bid, competitive coal lease sale for the lands included in the above LBA tracts, and issue the leases to the successful bidder. The legal descriptions for the Bureau's preferred configuration (Alternative 2), for the North Porcupine and South Porcupine LBA tracts can be found in Appendix G, pages G-29 and G-34 of the FEIS.

Your letter requested the U.S. Fish and Wildlife Service (Service) consider Appendix G of the FEIS and errata to serve as the biological assessment for the above two Federal actions. You have also requested the Service concur with the Bureau's determinations contained in your February 8, 2011, letter pursuant to section 7(a)(2) of the Endangered Species Act of 1973 (Act), as amended, 50 CFR § 402.13.

Based on the information provided in (1) the biological assessment (Appendix G of the Wright Area Coal Lease Applications FEIS and errata), (2) the conservation measures identified in Appendix D of the FEIS, and (3) the survey methods and results reported in the Threatened & Endangered Plant Species Survey Report, the Service concurs with the Bureau's determination that leasing the North Porcupine and South Porcupine LBA tracts, may affect, but is not likely to adversely affect the Ute ladies'-tresses orchid (*Spiranthes diluvialis*).

Appropriately timed surveys of suitable habitat within the above LBA tracts conducted in 1997, 1999, 2000, 2004 – 2006, 2009, and 2010 found no evidence of Ute ladies'-tresses orchids.

The Bureau has determined leasing the North Porcupine and South Porcupine LBA tracts is not likely to jeopardize the continued existence of the mountain plover (*Charadrius montanus*). We encourage project planners to develop and implement protective measures should mountain plovers occur within project areas. Measures to protect the mountain plover from further decline may include: (1) avoidance of suitable habitat during the plover nesting season (April 10 through July 10), (2) prohibition of ground disturbing activities in prairie dog towns, and (3) prohibition of any permanent above ground structures that may provide perches for avian predators or deter plovers from using preferred habitat. Suitable habitat for nesting mountain plovers includes grasslands, mixed grassland areas and short-grass prairie, shrub-steppe, plains, alkali flats, agricultural lands, cultivated lands, sod farms, and prairie dog towns. We strongly encourage you to develop protective measures with an assurance of implementation should mountain plovers be found within the project areas.

The Bureau has determined that leasing the North Porcupine and South Porcupine LBA tracts will have no effect to blowout penstemon (*Penstemon haydenii*). When the Bureau makes a no effect determination, concurrence from the Service is not required although we do appreciate receiving the information used to make that determination.

This concludes informal consultation and coordination pursuant to the regulations implementing the Act. This project should be re-analyzed if new information reveals effects of the action that may affect listed species or designated or proposed critical habitat (1) in a manner or to an extent not considered in this letter, (2) if the action is subsequently modified in a manner that causes an effect to a listed species or designated or proposed critical habitat that was not considered in this letter, and/or (3) if a new species is listed or critical habitat is designated that may be affected by this project.

For our internal tracking purposes, the Service would appreciate notification of any decision made on this project (such as issuance of a permit or signing of a Record of Decision or Decision Memo). Notification can be sent in writing to the letterhead address or by electronic mail to FW6_Federal_Activities_Cheyenne@fws.gov.

Thank you for your efforts to ensure the conservation of threatened and endangered species in Wyoming. If you have any questions regarding this letter or your responsibilities under the Act, please contact Bradley Rogers at (307) 684-1046.

cc: BLM, Field Manager, Buffalo Field Office, Buffalo, WY, (D. Spencer)
BLM,-State Office, Chief of Branch of Solid Minerals, Cheyenne, WY (B. Neuman)
BLM-State Office, T&E Coordinator, Cheyenne, WY (T. Abbott)
FWS, Federal Activities Specialist, Denver, CO (D. Carlson)
WGFD, Statewide Habitat Protection Coordinator, Cheyenne, WY (M. Flanderka)
WGFD, Non-Game Coordinator, Lander, WY (B. Oakleaf)

APPENDIX 4

APPEAL PROCEDURES

Form 1842-1
(September 2006)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

INFORMATION ON TAKING APPEALS TO THE INTERIOR BOARD OF LAND APPEALS

DO NOT APPEAL UNLESS
1. This decision is adverse to you,
AND
2. You believe it is incorrect

IF YOU APPEAL, THE FOLLOWING PROCEDURES MUST BE FOLLOWED

1. NOTICE OF APPEAL................	A person who wishes to appeal to the Interior Board of Land Appeals must file in the office of the officer who made the decision (not the Interior Board of Land Appeals) a notice that he wishes to appeal. A person served with the decision being appealed must transmit the *Notice of Appeal* in time for it to be filed in the office where it is required to be filed within 30 days after the date of service. If a decision is published in the FEDERAL REGISTER, a person not served with the decision must transmit a *Notice of Appeal* in time for it to be filed within 30 days after the date of publication (43 CFR 4.411 and 4.413).
2. WHERE TO FILE	
NOTICE OF APPEAL................	Bureau of Land Mangement, Wyoming High Plains District 2987 Prospector Drive, Casper, WY 82604
WITH COPY TO SOLICITOR...	U.S. Department of the Interior, Office of the Solicitor, Rocky Mountain Region 755 Parfet Street, Suite 151, Lakewood, CO 80215
3. STATEMENT OF REASONS	Within 30 days after filing the *Notice of Appeal*, file a complete statement of the reasons why you are appealing. This must be filed with the United States Department of the Interior, Office of Hearings and Appeals, Interior Board of Land Appeals, 801 N. Quincy Street, MS 300-QC, Arlington, Virginia 22203. If you fully stated your reasons for appealing when filing the *Notice of Appeal*, no additional statement is necessary (43 CFR 4.412 and 4.413).
WITH COPY TO SOLICITOR..............................	U.S. Department of the Interior, Office of the Solicitor, Rocky Mountain Region, 755 Parfet Street, #151, Lakewood, CO 80215
4. ADVERSE PARTIES.................	Within 15 days after each document is filed, each adverse party named in the decision and the Regional Solicitor or Field Solicitor having jurisdiction over the State in which the appeal arose must be served with a copy of: (a) the *Notice of Appeal*, (b) the Statement of Reasons, and (c) any other documents filed (43 CFR 4.413).
5. PROOF OF SERVICE...............	Within 15 days after any document is served on an adverse party, file proof of that service with the United States Department of the Interior, Office of Hearings and Appeals, Interior Board of Land Appeals, 801 N. Quincy Street, MS 300-QC, Arlington, Virginia 22203. This may consist of a certified or registered mail "Return Receipt Card" signed by the adverse party (43 CFR 4.401(c)).
6. REQUEST FOR STAY.............	Except where program-specific regulations place this decision in full force and effect or provide for an automatic stay, the decision becomes effective upon the expiration of the time allowed for filing an appeal unless a petition for a stay is timely filed together with a *Notice of Appeal* (43 CFR 4.21). If you wish to file a petition for a stay of the effectiveness of this decision during the time that your appeal is being reviewed by the Interior Board of Land Appeals, the petition for a stay must accompany your *Notice of Appeal* (43 CFR 4.21 or 43 CFR 2801.10 or 43 CFR 2881.10). A petition for a stay is required to show sufficient justification based on the standards listed below. Copies of the *Notice of Appeal* and Petition for a Stay **must** also be submitted to each party named in this decision and to the Interior Board of Land Appeals and to the appropriate Office of the Solicitor (43 CFR 4.413) at the same time the original documents are filed with this office. If you request a stay, you have the burden of proof to demonstrate that a stay should be granted. **Standards for Obtaining a Stay.** Except as otherwise provided by law or other pertinent regulations, a petition for a stay of a decision pending appeal shall show sufficient justification based on the following standards: (1) the relative harm to the parties if the stay is granted or denied, (2) the likelihood of the appellant's success on the merits, (3) the likelihood of immediate and irreparable harm if the stay is not granted, and (4) whether the public interest favors granting the stay.

Unless these procedures are followed, your appeal will be subject to dismissal (43 CFR 4.402). Be certain that **all** communications are identified by serial number of the case being appealed.

NOTE: A document is not filed until it is actually received in the proper office (43 CFR 4.401(a)). See 43 CFR Part 4, Subpart B for general rules relating to procedures and practice involving appeals.

(Continued on page 2)

43 CFR SUBPART 1821--GENERAL INFORMATION

Sec. 1821.10 Where are BLM offices located? (a) In addition to the Headquarters Office in Washington, D.C. and seven national level support and service centers, BLM operates 12 State Offices each having several subsidiary offices called Field Offices. The addresses of the State Offices can be found in the most recent edition of 43 CFR 1821.10. The State Office geographical areas of jurisdiction are as follows:

STATE OFFICES AND AREAS OF JURISDICTION:

Alaska State Office ---------- Alaska
Arizona State Office --------- Arizona
California State Office ------- California
Colorado State Office -------- Colorado
Eastern States Office --------- Arkansas, Iowa, Louisiana, Minnesota, Missouri and, all States east of the Mississippi River
Idaho State Office ------------- Idaho
Montana State Office --------- Montana, North Dakota and South Dakota
Nevada State Office ----------- Nevada
New Mexico State Office ---- New Mexico, Kansas, Oklahoma and Texas
Oregon State Office ----------- Oregon and Washington
Utah State Office -------------- Utah
Wyoming State Office -------- Wyoming and Nebraska

(b) A list of the names, addresses, and geographical areas of jurisdiction of all Field Offices of the Bureau of Land Management can be obtained at the above addresses or any office of the Bureau of Land Management, including the Washington Office, Bureau of Land Management, 1849 C Street, NW, Washington, DC 20240.

Exhibit 6

EIA Form 923 Data for North Antelope Rochelle coal mine (2010)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Data Extracted from EIA Form 423 and 923 Data for 2010, Presents Coal-fired Power Plants Fueled by North Antelope Rochelle Coal Mine**													
2	Prepared by Jeremy Nichols, Climate and Energy Program Director for WildEarth Guardians, Aug. 26, 2011													
3	**Year**	**Month**	**Plant ID**	**Plant Name**	**State**	**Energy_ Source**	**Fuel_ Group**	**CoalMine _Type**	**CoalMine_State**	**CoalMine _County**	**CoalMine_Name**	**Supplier**	**Quantity**	**Operator Name**
4	2010	5	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	24,018	Tennessee Valley Authority
5	2010	2	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	23,272	Tennessee Valley Authority
6	2010	6	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	20,862	Tennessee Valley Authority
7	2010	4	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	10,428	Tennessee Valley Authority
8	2010	11	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,103	Tennessee Valley Authority
9	2010	3	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	8,791	Tennessee Valley Authority
10	2010	1	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	7,786	Tennessee Valley Authority
11	2010	2	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	3,923	Tennessee Valley Authority
12	2010	7	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	2,403	Tennessee Valley Authority
13	2010	7	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	2,060	Tennessee Valley Authority
14	2010	7	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	705	Tennessee Valley Authority
15	2010	3	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	699	Tennessee Valley Authority
16	2010	1	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	446	Tennessee Valley Authority
17	2010	6	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	290	Tennessee Valley Authority
18	2010	8	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	246	Tennessee Valley Authority
19	2010	2	47	Colbert	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	99	Tennessee Valley Authority
20	2010	8	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	351,577	Alabama Power Co
21	2010	7	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	303,914	Alabama Power Co
22	2010	11	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	303,597	Alabama Power Co
23	2010	12	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	302,518	Alabama Power Co
24	2010	10	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	301,159	Alabama Power Co
25	2010	9	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	271,897	Alabama Power Co
26	2010	5	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	175,600	Alabama Power Co
27	2010	2	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	143,312	Alabama Power Co
28	2010	3	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	127,250	Alabama Power Co
29	2010	1	6002	James H Miller Jr	AL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	94,697	Alabama Power Co
30	2010	11	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	137,199	Southwestern Electric Power Co
31	2010	9	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	105,855	Southwestern Electric Power Co
32	2010	4	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	91,128	Southwestern Electric Power Co
33	2010	2	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	90,486	Southwestern Electric Power Co
34	2010	8	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	76,531	Southwestern Electric Power Co
35	2010	10	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	76,344	Southwestern Electric Power Co
36	2010	6	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	75,128	Southwestern Electric Power Co
37	2010	12	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	74,870	Southwestern Electric Power Co
38	2010	5	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	60,801	Southwestern Electric Power Co
39	2010	1	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	60,448	Southwestern Electric Power Co
40	2010	3	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	45,513	Southwestern Electric Power Co
41	2010	7	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	45,341	Southwestern Electric Power Co
42	2010	4	6138	Flint Creek	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	30,278	Southwestern Electric Power Co
43	2010	9	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	570,675	Entergy Arkansas Inc
44	2010	12	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	488,240	Entergy Arkansas Inc
45	2010	2	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	441,811	Entergy Arkansas Inc
46	2010	1	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	418,882	Entergy Arkansas Inc
47	2010	8	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	376,231	Entergy Arkansas Inc
48	2010	6	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	358,723	Entergy Arkansas Inc
49	2010	7	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	358,354	Entergy Arkansas Inc
50	2010	3	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	342,630	Entergy Arkansas Inc
51	2010	4	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	295,602	Entergy Arkansas Inc
52	2010	10	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	277,289	Entergy Arkansas Inc
53	2010	5	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	195,475	Entergy Arkansas Inc
54	2010	11	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	147,096	Entergy Arkansas Inc
55	2010	4	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	98,436	Entergy Arkansas Inc
56	2010	11	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	65,463	Entergy Arkansas Inc
57	2010	4	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	49,468	Entergy Arkansas Inc
58	2010	7	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,134	Entergy Arkansas Inc
59	2010	8	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	32,771	Entergy Arkansas Inc
60	2010	11	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,527	Entergy Arkansas Inc
61	2010	12	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,434	Entergy Arkansas Inc
62	2010	5	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,364	Entergy Arkansas Inc
63	2010	9	6641	Independence	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,240	Entergy Arkansas Inc
64	2010	5	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	292,427	Entergy Arkansas Inc
65	2010	3	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	245,452	Entergy Arkansas Inc
66	2010	10	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	179,558	Entergy Arkansas Inc
67	2010	10	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	178,747	Entergy Arkansas Inc
68	2010	7	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	163,968	Entergy Arkansas Inc
69	2010	3	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	163,637	Entergy Arkansas Inc
70	2010	12	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	163,253	Entergy Arkansas Inc

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71	2010	11	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	163,133	Entergy Arkansas Inc
72	2010	2	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	147,096	Entergy Arkansas Inc
73	2010	7	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	146,788	Entergy Arkansas Inc
74	2010	1	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	144,128	Entergy Arkansas Inc
75	2010	6	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	131,151	Entergy Arkansas Inc
76	2010	8	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	130,826	Entergy Arkansas Inc
77	2010	6	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	130,771	Entergy Arkansas Inc
78	2010	5	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	114,969	Entergy Arkansas Inc
79	2010	5	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	114,760	Entergy Arkansas Inc
80	2010	9	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	114,713	Entergy Arkansas Inc
81	2010	3	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	114,204	Entergy Arkansas Inc
82	2010	3	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK	114,186	Entergy Arkansas Inc
83	2010	2	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	114,168	Entergy Arkansas Inc
84	2010	6	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	98,317	Entergy Arkansas Inc
85	2010	1	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	97,641	Entergy Arkansas Inc
86	2010	12	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	96,744	Entergy Arkansas Inc
87	2010	1	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK	96,598	Entergy Arkansas Inc
88	2010	2	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	96,333	Entergy Arkansas Inc
89	2010	11	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	81,853	Entergy Arkansas Inc
90	2010	7	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	81,210	Entergy Arkansas Inc
91	2010	10	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	66,015	Entergy Arkansas Inc
92	2010	8	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	65,588	Entergy Arkansas Inc
93	2010	8	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	65,502	Entergy Arkansas Inc
94	2010	12	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	65,312	Entergy Arkansas Inc
95	2010	9	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	64,871	Entergy Arkansas Inc
96	2010	1	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	49,337	Entergy Arkansas Inc
97	2010	8	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	49,260	Entergy Arkansas Inc
98	2010	5	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	49,129	Entergy Arkansas Inc
99	2010	9	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	48,741	Entergy Arkansas Inc
100	2010	6	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	48,728	Entergy Arkansas Inc
101	2010	12	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ENSERCO	48,571	Entergy Arkansas Inc
102	2010	2	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK	48,570	Entergy Arkansas Inc
103	2010	7	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	33,073	Entergy Arkansas Inc
104	2010	11	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,836	Entergy Arkansas Inc
105	2010	1	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK	32,756	Entergy Arkansas Inc
106	2010	4	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	32,677	Entergy Arkansas Inc
107	2010	9	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	16,402	Entergy Arkansas Inc
108	2010	4	6009	White Bluff	AR	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	16,248	Entergy Arkansas Inc
109	2010	12	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK	201,450	Tucson Electric Power Co
110	2010	4	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	145,101	Tucson Electric Power Co
111	2010	6	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	130,811	Tucson Electric Power Co
112	2010	5	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	130,684	Tucson Electric Power Co
113	2010	8	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	116,369	Tucson Electric Power Co
114	2010	1	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	RIO TINTO	115,452	Tucson Electric Power Co
115	2010	2	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	115,235	Tucson Electric Power Co
116	2010	10	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	114,013	Tucson Electric Power Co
117	2010	9	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	101,246	Tucson Electric Power Co
118	2010	12	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	101,239	Tucson Electric Power Co
119	2010	1	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	87,408	Tucson Electric Power Co
120	2010	11	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	85,360	Tucson Electric Power Co
121	2010	7	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	72,891	Tucson Electric Power Co
122	2010	3	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	58,150	Tucson Electric Power Co
123	2010	4	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	14,555	Tucson Electric Power Co
124	2010	2	8223	Springerville	AZ	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	14,528	Tucson Electric Power Co
125	2010	4	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	42,324	Colorado Springs City of
126	2010	3	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	42,245	Colorado Springs City of
127	2010	6	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	28,292	Colorado Springs City of
128	2010	9	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	28,264	Colorado Springs City of
129	2010	7	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	28,244	Colorado Springs City of
130	2010	5	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	28,170	Colorado Springs City of
131	2010	7	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	14,130	Colorado Springs City of
132	2010	6	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	14,127	Colorado Springs City of
133	2010	1	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	14,122	Colorado Springs City of
134	2010	5	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	14,114	Colorado Springs City of
135	2010	6	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NRG	14,110	Colorado Springs City of
136	2010	2	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	14,101	Colorado Springs City of
137	2010	1	492	Martin Drake	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	14,093	Colorado Springs City of
138	2010	10	8219	Ray D Nixon	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	98,650	Colorado Springs City of
139	2010	8	8219	Ray D Nixon	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	70,620	Colorado Springs City of
140	2010	6	8219	Ray D Nixon	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	70,575	Colorado Springs City of
141	2010	3	8219	Ray D Nixon	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	70,541	Colorado Springs City of
142	2010	11	8219	Ray D Nixon	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	70,500	Colorado Springs City of
143	2010	2	8219	Ray D Nixon	CO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	70,179	Colorado Springs City of

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144	2010	9	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	56,470	Colorado Springs City of
145	2010	1	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	56,272	Colorado Springs City of
146	2010	1	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	42,350	Colorado Springs City of
147	2010	7	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	42,321	Colorado Springs City of
148	2010	7	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	NRG	28,267	Colorado Springs City of
149	2010	4	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	28,244	Colorado Springs City of
150	2010	5	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	28,233	Colorado Springs City of
151	2010	6	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	28,224	Colorado Springs City of
152	2010	12	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES II LLC	28,198	Colorado Springs City of
153	2010	6	8219	Ray D Nixon	CO	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	NRG	14,124	Colorado Springs City of
154	2010	4	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	189,411	Georgia Power Co
155	2010	1	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	189,243	Georgia Power Co
156	2010	6	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	160,586	Georgia Power Co
157	2010	5	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	148,135	Georgia Power Co
158	2010	3	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	131,450	Georgia Power Co
159	2010	2	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	102,493	Georgia Power Co
160	2010	1	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	44,104	Georgia Power Co
161	2010	1	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	29,916	Georgia Power Co
162	2010	1	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	29,765	Georgia Power Co
163	2010	1	6257	Scherer	GA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	29,349	Georgia Power Co
164	2010	11	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	97,457	Archer Daniels Midland Co
165	2010	7	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	81,533	Archer Daniels Midland Co
166	2010	10	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	81,288	Archer Daniels Midland Co
167	2010	8	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	65,858	Archer Daniels Midland Co
168	2010	6	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	65,240	Archer Daniels Midland Co
169	2010	9	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	65,126	Archer Daniels Midland Co
170	2010	12	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	63,308	Archer Daniels Midland Co
171	2010	5	10864	Archer Daniels Midland Ce	IA	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	61,859	Archer Daniels Midland Co
172	2010	6	10865	Archer Daniels Midland De	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,916	Archer Daniels Midland Co
173	2010	11	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	694,360	Dynegy Midwest Generation Inc
174	2010	12	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	693,770	Dynegy Midwest Generation Inc
175	2010	10	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	666,363	Dynegy Midwest Generation Inc
176	2010	3	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	663,918	Dynegy Midwest Generation Inc
177	2010	9	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	646,598	Dynegy Midwest Generation Inc
178	2010	2	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	624,969	Dynegy Midwest Generation Inc
179	2010	8	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	553,855	Dynegy Midwest Generation Inc
180	2010	1	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	549,933	Dynegy Midwest Generation Inc
181	2010	7	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	523,206	Dynegy Midwest Generation Inc
182	2010	4	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	521,596	Dynegy Midwest Generation Inc
183	2010	5	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	502,962	Dynegy Midwest Generation Inc
184	2010	6	889	Baldwin Energy Complex	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	482,074	Dynegy Midwest Generation Inc
185	2010	10	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	180,184	Ameren Energy Generating Co
186	2010	8	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	166,983	Ameren Energy Generating Co
187	2010	3	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	152,888	Ameren Energy Generating Co
188	2010	6	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	139,035	Ameren Energy Generating Co
189	2010	9	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	125,319	Ameren Energy Generating Co
190	2010	4	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	125,217	Ameren Energy Generating Co
191	2010	5	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	124,792	Ameren Energy Generating Co
192	2010	12	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	124,460	Ameren Energy Generating Co
193	2010	12	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	110,616	Ameren Energy Generating Co
194	2010	11	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	97,337	Ameren Energy Generating Co
195	2010	11	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	83,319	Ameren Energy Generating Co
196	2010	7	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	69,724	Ameren Energy Generating Co
197	2010	7	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	42,118	Ameren Energy Generating Co
198	2010	6	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,975	Ameren Energy Generating Co
199	2010	4	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,862	Ameren Energy Generating Co
200	2010	3	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,771	Ameren Energy Generating Co
201	2010	2	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,757	Ameren Energy Generating Co
202	2010	10	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,719	Ameren Energy Generating Co
203	2010	1	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,600	Ameren Energy Generating Co
204	2010	5	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,599	Ameren Energy Generating Co
205	2010	9	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,589	Ameren Energy Generating Co
206	2010	8	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,493	Ameren Energy Generating Co
207	2010	11	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	41,448	Ameren Energy Generating Co
208	2010	2	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,783	Ameren Energy Generating Co
209	2010	1	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,483	Ameren Energy Generating Co
210	2010	1	861	Coffeen	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,669	Ameren Energy Generating Co
211	2010	5	867	Crawford	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	103,775	Midwest Generations EME LLC
212	2010	6	867	Crawford	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	87,245	Midwest Generations EME LLC
213	2010	7	867	Crawford	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	67,356	Midwest Generations EME LLC
214	2010	4	867	Crawford	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	66,523	Midwest Generations EME LLC
215	2010	2	867	Crawford	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	57,374	Midwest Generations EME LLC
216	2010	1	867	Crawford	IL	SUB	Coal	S		WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	55,784	Midwest Generations EME LLC

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217	2010	3	867	Crawford	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	33,861	Midwest Generations EME LLC
218	2010	10	867	Crawford	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,535	Midwest Generations EME LLC
219	2010	11	867	Crawford	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,382	Midwest Generations EME LLC
220	2010	12	867	Crawford	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,400	Midwest Generations EME LLC
221	2010	9	867	Crawford	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	8,268	Midwest Generations EME LLC
222	2010	4	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	81,437	Ameren Energy Resources Genera
223	2010	7	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	81,142	Ameren Energy Resources Genera
224	2010	5	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	81,067	Ameren Energy Resources Genera
225	2010	3	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	78,924	Ameren Energy Resources Genera
226	2010	12	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	65,276	Ameren Energy Resources Genera
227	2010	2	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,448	Ameren Energy Resources Genera
228	2010	10	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,112	Ameren Energy Resources Genera
229	2010	9	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,094	Ameren Energy Resources Genera
230	2010	6	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,803	Ameren Energy Resources Genera
231	2010	11	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,799	Ameren Energy Resources Genera
232	2010	1	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	29,941	Ameren Energy Resources Genera
233	2010	1	6016	Duck Creek	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	16,018	Ameren Energy Resources Genera
234	2010	12	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	175,862	Ameren Energy Resources Genera
235	2010	9	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	150,225	Ameren Energy Resources Genera
236	2010	11	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	148,340	Ameren Energy Resources Genera
237	2010	4	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	147,235	Ameren Energy Resources Genera
238	2010	7	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	131,690	Ameren Energy Resources Genera
239	2010	8	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	131,281	Ameren Energy Resources Genera
240	2010	3	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	113,418	Ameren Energy Resources Genera
241	2010	6	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	99,046	Ameren Energy Resources Genera
242	2010	5	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	98,298	Ameren Energy Resources Genera
243	2010	1	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	79,937	Ameren Energy Resources Genera
244	2010	2	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	78,965	Ameren Energy Resources Genera
245	2010	10	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,284	Ameren Energy Resources Genera
246	2010	10	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	48,999	Ameren Energy Resources Genera
247	2010	2	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,933	Ameren Energy Resources Genera
248	2010	2	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,818	Ameren Energy Resources Genera
249	2010	1	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	46,227	Ameren Energy Resources Genera
250	2010	1	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	45,670	Ameren Energy Resources Genera
251	2010	10	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,664	Ameren Energy Resources Genera
252	2010	8	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,152	Ameren Energy Resources Genera
253	2010	3	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,904	Ameren Energy Resources Genera
254	2010	7	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,551	Ameren Energy Resources Genera
255	2010	6	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,531	Ameren Energy Resources Genera
256	2010	4	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,507	Ameren Energy Resources Genera
257	2010	4	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,410	Ameren Energy Resources Genera
258	2010	9	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,410	Ameren Energy Resources Genera
259	2010	6	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,405	Ameren Energy Resources Genera
260	2010	11	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,383	Ameren Energy Resources Genera
261	2010	5	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,376	Ameren Energy Resources Genera
262	2010	3	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,345	Ameren Energy Resources Genera
263	2010	5	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,341	Ameren Energy Resources Genera
264	2010	8	856	E D Edwards	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,257	Ameren Energy Resources Genera
265	2010	7	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	58,057	Midwest Generations EME LLC
266	2010	2	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	44,829	Midwest Generations EME LLC
267	2010	6	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	42,410	Midwest Generations EME LLC
268	2010	8	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	40,050	Midwest Generations EME LLC
269	2010	1	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	36,650	Midwest Generations EME LLC
270	2010	9	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,702	Midwest Generations EME LLC
271	2010	3	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	29,952	Midwest Generations EME LLC
272	2010	10	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,697	Midwest Generations EME LLC
273	2010	11	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	20,478	Midwest Generations EME LLC
274	2010	4	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	7,577	Midwest Generations EME LLC
275	2010	12	886	Fisk Street	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	7,524	Midwest Generations EME LLC
276	2010	2	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	212,741	Dynegy Midwest Generation Inc
277	2010	11	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	203,506	Dynegy Midwest Generation Inc
278	2010	9	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	188,084	Dynegy Midwest Generation Inc
279	2010	3	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	173,056	Dynegy Midwest Generation Inc
280	2010	7	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	172,830	Dynegy Midwest Generation Inc
281	2010	5	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	172,052	Dynegy Midwest Generation Inc
282	2010	4	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	171,729	Dynegy Midwest Generation Inc
283	2010	1	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	169,858	Dynegy Midwest Generation Inc
284	2010	12	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	154,732	Dynegy Midwest Generation Inc
285	2010	8	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	140,789	Dynegy Midwest Generation Inc
286	2010	6	891	Havana	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	123,703	Dynegy Midwest Generation Inc
287	2010	9	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	255,288	Midwest Generations EME LLC
288	2010	5	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	253,576	Midwest Generations EME LLC
289	2010	3	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	248,515	Midwest Generations EME LLC

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290	2010	6	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	245,158	Midwest Generations EME LLC
291	2010	2	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	236,062	Midwest Generations EME LLC
292	2010	8	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	187,476	Midwest Generations EME LLC
293	2010	7	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	172,963	Midwest Generations EME LLC
294	2010	4	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	168,918	Midwest Generations EME LLC
295	2010	11	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	144,574	Midwest Generations EME LLC
296	2010	1	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	136,134	Midwest Generations EME LLC
297	2010	10	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	130,379	Midwest Generations EME LLC
298	2010	12	384	Joliet 29	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	94,333	Midwest Generations EME LLC
299	2010	5	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	90,065	Midwest Generations EME LLC
300	2010	6	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	66,071	Midwest Generations EME LLC
301	2010	1	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	65,920	Midwest Generations EME LLC
302	2010	9	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	55,531	Midwest Generations EME LLC
303	2010	10	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	50,264	Midwest Generations EME LLC
304	2010	7	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	40,442	Midwest Generations EME LLC
305	2010	11	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	34,829	Midwest Generations EME LLC
306	2010	4	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	27,038	Midwest Generations EME LLC
307	2010	8	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	26,213	Midwest Generations EME LLC
308	2010	12	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	14,717	Midwest Generations EME LLC
309	2010	3	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	12,264	Midwest Generations EME LLC
310	2010	2	874	Joliet 9	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	3,355	Midwest Generations EME LLC
311	2010	7	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	80,159	Electric Energy Inc
312	2010	3	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	64,059	Electric Energy Inc
313	2010	10	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	47,707	Electric Energy Inc
314	2010	1	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	47,538	Electric Energy Inc
315	2010	11	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	32,173	Electric Energy Inc
316	2010	8	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	32,059	Electric Energy Inc
317	2010	2	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	32,007	Electric Energy Inc
318	2010	5	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	31,874	Electric Energy Inc
319	2010	12	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	31,730	Electric Energy Inc
320	2010	6	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,115	Electric Energy Inc
321	2010	4	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,045	Electric Energy Inc
322	2010	9	887	Joppa Steam	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,014	Electric Energy Inc
323	2010	6	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	129,627	Dominion Energy Services Co
324	2010	5	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	95,698	Dominion Energy Services Co
325	2010	7	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	95,500	Dominion Energy Services Co
326	2010	8	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	95,367	Dominion Energy Services Co
327	2010	9	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	95,159	Dominion Energy Services Co
328	2010	12	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	95,024	Dominion Energy Services Co
329	2010	5	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	92,878	Dominion Energy Services Co
330	2010	4	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	80,162	Dominion Energy Services Co
331	2010	10	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	80,120	Dominion Energy Services Co
332	2010	6	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	80,095	Dominion Energy Services Co
333	2010	4	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	80,086	Dominion Energy Services Co
334	2010	3	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	79,833	Dominion Energy Services Co
335	2010	1	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	77,403	Dominion Energy Services Co
336	2010	11	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	64,198	Dominion Energy Services Co
337	2010	11	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	64,096	Dominion Energy Services Co
338	2010	10	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	63,780	Dominion Energy Services Co
339	2010	12	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	63,749	Dominion Energy Services Co
340	2010	1	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	63,554	Dominion Energy Services Co
341	2010	2	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	63,150	Dominion Energy Services Co
342	2010	2	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	63,129	Dominion Energy Services Co
343	2010	7	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	48,259	Dominion Energy Services Co
344	2010	9	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	48,100	Dominion Energy Services Co
345	2010	3	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	47,707	Dominion Energy Services Co
346	2010	8	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	32,023	Dominion Energy Services Co
347	2010	7	876	Kincaid Generation LLC	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	31,846	Dominion Energy Services Co
348	2010	2	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	39,071	Ameren Energy Generating Co
349	2010	3	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,997	Ameren Energy Generating Co
350	2010	8	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	30,448	Ameren Energy Generating Co
351	2010	6	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,442	Ameren Energy Generating Co
352	2010	3	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,412	Ameren Energy Generating Co
353	2010	7	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,321	Ameren Energy Generating Co
354	2010	12	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,054	Ameren Energy Generating Co
355	2010	6	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	22,858	Ameren Energy Generating Co
356	2010	7	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	22,858	Ameren Energy Generating Co
357	2010	5	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	18,366	Ameren Energy Generating Co
358	2010	1	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,324	Ameren Energy Generating Co
359	2010	4	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,135	Ameren Energy Generating Co
360	2010	2	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	14,447	Ameren Energy Generating Co
361	2010	8	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	9,283	Ameren Energy Generating Co
362	2010	4	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	8,493	Ameren Energy Generating Co

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363	2010	5	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	7,758	Ameren Energy Generating Co
364	2010	9	864	Meredosia	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	1,885	Ameren Energy Generating Co
365	2010	2	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	51,364	Ameren Energy Generating Co
366	2010	7	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	34,611	Ameren Energy Generating Co
367	2010	3	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	34,528	Ameren Energy Generating Co
368	2010	8	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	34,335	Ameren Energy Generating Co
369	2010	9	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,745	Ameren Energy Generating Co
370	2010	4	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,395	Ameren Energy Generating Co
371	2010	5	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,369	Ameren Energy Generating Co
372	2010	3	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	17,346	Ameren Energy Generating Co
373	2010	5	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,231	Ameren Energy Generating Co
374	2010	4	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,217	Ameren Energy Generating Co
375	2010	7	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,184	Ameren Energy Generating Co
376	2010	2	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,098	Ameren Energy Generating Co
377	2010	6	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	17,025	Ameren Energy Generating Co
378	2010	1	6017	Newton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	15,405	Ameren Energy Generating Co
379	2010	10	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	506,418	Midwest Generations EME LLC
380	2010	8	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	457,544	Midwest Generations EME LLC
381	2010	12	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	443,052	Midwest Generations EME LLC
382	2010	11	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	391,340	Midwest Generations EME LLC
383	2010	3	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	387,017	Midwest Generations EME LLC
384	2010	7	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	377,222	Midwest Generations EME LLC
385	2010	4	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	374,050	Midwest Generations EME LLC
386	2010	9	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	359,741	Midwest Generations EME LLC
387	2010	2	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	285,155	Midwest Generations EME LLC
388	2010	6	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	245,792	Midwest Generations EME LLC
389	2010	5	879	Powerton	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	49,200	Midwest Generations EME LLC
390	2010	3	897	Vermilion	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	65,719	Dynegy Midwest Generation Inc
391	2010	4	897	Vermilion	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	DYNEGY COAL TRANDING AND T	33,186	Dynegy Midwest Generation Inc
392	2010	9	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,806	Midwest Generations EME LLC
393	2010	8	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,639	Midwest Generations EME LLC
394	2010	12	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,049	Midwest Generations EME LLC
395	2010	2	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	31,135	Midwest Generations EME LLC
396	2010	10	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,500	Midwest Generations EME LLC
397	2010	6	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,473	Midwest Generations EME LLC
398	2010	4	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	16,455	Midwest Generations EME LLC
399	2010	11	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,442	Midwest Generations EME LLC
400	2010	7	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,313	Midwest Generations EME LLC
401	2010	1	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	16,225	Midwest Generations EME LLC
402	2010	3	883	Waukegan	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	16,156	Midwest Generations EME LLC
403	2010	5	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	190,423	Midwest Generations EME LLC
404	2010	7	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	187,175	Midwest Generations EME LLC
405	2010	4	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	154,000	Midwest Generations EME LLC
406	2010	1	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	126,661	Midwest Generations EME LLC
407	2010	9	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	124,052	Midwest Generations EME LLC
408	2010	8	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	107,637	Midwest Generations EME LLC
409	2010	2	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	104,980	Midwest Generations EME LLC
410	2010	6	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	98,921	Midwest Generations EME LLC
411	2010	11	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	96,757	Midwest Generations EME LLC
412	2010	10	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	91,074	Midwest Generations EME LLC
413	2010	3	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	80,875	Midwest Generations EME LLC
414	2010	12	884	Will County	IL	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,874	Midwest Generations EME LLC
415	2010	4	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	154,949	Indiana-Kentucky Electric Corp
416	2010	4	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	137,572	Indiana-Kentucky Electric Corp
417	2010	3	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	102,861	Indiana-Kentucky Electric Corp
418	2010	6	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	86,485	Indiana-Kentucky Electric Corp
419	2010	7	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	86,414	Indiana-Kentucky Electric Corp
420	2010	2	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	86,331	Indiana-Kentucky Electric Corp
421	2010	5	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	85,588	Indiana-Kentucky Electric Corp
422	2010	8	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	69,320	Indiana-Kentucky Electric Corp
423	2010	9	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	68,909	Indiana-Kentucky Electric Corp
424	2010	11	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	51,814	Indiana-Kentucky Electric Corp
425	2010	10	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	51,809	Indiana-Kentucky Electric Corp
426	2010	1	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	48,795	Indiana-Kentucky Electric Corp
427	2010	6	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,517	Indiana-Kentucky Electric Corp
428	2010	12	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,427	Indiana-Kentucky Electric Corp
429	2010	5	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,296	Indiana-Kentucky Electric Corp
430	2010	7	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,263	Indiana-Kentucky Electric Corp
431	2010	10	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,224	Indiana-Kentucky Electric Corp
432	2010	8	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,191	Indiana-Kentucky Electric Corp
433	2010	9	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	34,069	Indiana-Kentucky Electric Corp
434	2010	11	983	Clifty Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	17,221	Indiana-Kentucky Electric Corp
435	2010	2	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	70,291	Northern Indiana Pub Serv Co

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436	2010	3	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	67,696	Northern Indiana Pub Serv Co
437	2010	5	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	59,919	Northern Indiana Pub Serv Co
438	2010	4	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	59,917	Northern Indiana Pub Serv Co
439	2010	1	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	59,647	Northern Indiana Pub Serv Co
440	2010	7	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	45,581	Northern Indiana Pub Serv Co
441	2010	6	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	45,286	Northern Indiana Pub Serv Co
442	2010	11	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	44,418	Northern Indiana Pub Serv Co
443	2010	8	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,896	Northern Indiana Pub Serv Co
444	2010	8	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	20,739	Northern Indiana Pub Serv Co
445	2010	9	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	15,180	Northern Indiana Pub Serv Co
446	2010	10	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	15,170	Northern Indiana Pub Serv Co
447	2010	12	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	15,015	Northern Indiana Pub Serv Co
448	2010	7	997	Michigan City	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	9,246	Northern Indiana Pub Serv Co
449	2010	9	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	90,419	Northern Indiana Pub Serv Co
450	2010	4	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	84,962	Northern Indiana Pub Serv Co
451	2010	7	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	75,244	Northern Indiana Pub Serv Co
452	2010	10	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	75,205	Northern Indiana Pub Serv Co
453	2010	11	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	60,650	Northern Indiana Pub Serv Co
454	2010	6	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	59,775	Northern Indiana Pub Serv Co
455	2010	12	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	57,964	Northern Indiana Pub Serv Co
456	2010	10	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	45,139	Northern Indiana Pub Serv Co
457	2010	8	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	42,134	Northern Indiana Pub Serv Co
458	2010	1	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	40,152	Northern Indiana Pub Serv Co
459	2010	3	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	33,634	Northern Indiana Pub Serv Co
460	2010	5	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	30,495	Northern Indiana Pub Serv Co
461	2010	11	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	30,090	Northern Indiana Pub Serv Co
462	2010	8	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	30,013	Northern Indiana Pub Serv Co
463	2010	2	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	17,986	Northern Indiana Pub Serv Co
464	2010	9	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ENSERCO	15,022	Northern Indiana Pub Serv Co
465	2010	7	6085	R M Schahfer	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	2,428	Northern Indiana Pub Serv Co
466	2010	3	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	616,390	Indiana Michigan Power Co
467	2010	8	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	600,644	Indiana Michigan Power Co
468	2010	2	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	581,263	Indiana Michigan Power Co
469	2010	7	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	524,679	Indiana Michigan Power Co
470	2010	10	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	505,069	Indiana Michigan Power Co
471	2010	1	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	449,839	Indiana Michigan Power Co
472	2010	5	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	434,526	Indiana Michigan Power Co
473	2010	4	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	426,280	Indiana Michigan Power Co
474	2010	11	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	421,364	Indiana Michigan Power Co
475	2010	9	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	311,867	Indiana Michigan Power Co
476	2010	9	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	261,723	Indiana Michigan Power Co
477	2010	6	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	196,600	Indiana Michigan Power Co
478	2010	6	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	181,721	Indiana Michigan Power Co
479	2010	1	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	135,354	Indiana Michigan Power Co
480	2010	4	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	116,124	Indiana Michigan Power Co
481	2010	5	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	60,091	Indiana Michigan Power Co
482	2010	10	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	59,013	Indiana Michigan Power Co
483	2010	6	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	2,764	Indiana Michigan Power Co
484	2010	11	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	121	Indiana Michigan Power Co
485	2010	7	6166	Rockport	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	120	Indiana Michigan Power Co
486	2010	12	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	206,601	State Line Energy LLC
487	2010	10	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	82,877	State Line Energy LLC
488	2010	9	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	41,684	State Line Energy LLC
489	2010	11	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	41,659	State Line Energy LLC
490	2010	7	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	27,743	State Line Energy LLC
491	2010	8	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	27,672	State Line Energy LLC
492	2010	3	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	27,614	State Line Energy LLC
493	2010	2	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ANTELOPE	13,811	State Line Energy LLC
494	2010	1	981	State Line Energy	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	13,531	State Line Energy LLC
495	2010	8	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	137,115	Indiana Michigan Power Co
496	2010	2	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	100,324	Indiana Michigan Power Co
497	2010	9	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	100,112	Indiana Michigan Power Co
498	2010	7	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	97,228	Indiana Michigan Power Co
499	2010	11	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	86,873	Indiana Michigan Power Co
500	2010	3	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	84,948	Indiana Michigan Power Co
501	2010	4	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	80,955	Indiana Michigan Power Co
502	2010	6	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	64,474	Indiana Michigan Power Co
503	2010	10	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	52,555	Indiana Michigan Power Co
504	2010	5	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	43,498	Indiana Michigan Power Co
505	2010	1	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	26,951	Indiana Michigan Power Co
506	2010	6	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,511	Indiana Michigan Power Co
507	2010	10	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	6,779	Indiana Michigan Power Co
508	2010	4	988	Tanners Creek	IN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	121	Indiana Michigan Power Co

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509	2010	10	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	56,796	Sunflower Electric Power Corp
510	2010	11	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	56,655	Sunflower Electric Power Corp
511	2010	6	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	43,895	Sunflower Electric Power Corp
512	2010	8	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	43,677	Sunflower Electric Power Corp
513	2010	9	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	42,391	Sunflower Electric Power Corp
514	2010	12	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	40,491	Sunflower Electric Power Corp
515	2010	3	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	28,610	Sunflower Electric Power Corp
516	2010	2	108	Holcomb	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,479	Sunflower Electric Power Corp
517	2010	3	1241	La Cygne	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	30,140	Kansas City Power & Light Co
518	2010	5	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,302	Empire District Electric Co
519	2010	8	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,015	Empire District Electric Co
520	2010	4	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	9,174	Empire District Electric Co
521	2010	9	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	6,949	Empire District Electric Co
522	2010	11	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	5,161	Empire District Electric Co
523	2010	7	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	4,950	Empire District Electric Co
524	2010	10	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	4,921	Empire District Electric Co
525	2010	6	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	4,632	Empire District Electric Co
526	2010	3	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	4,613	Empire District Electric Co
527	2010	2	1239	Riverton	KS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	3,858	Empire District Electric Co
528	2010	3	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	127,150	Tennessee Valley Authority
529	2010	4	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	95,549	Tennessee Valley Authority
530	2010	5	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	48,849	Tennessee Valley Authority
531	2010	11	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,630	Tennessee Valley Authority
532	2010	2	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	31,834	Tennessee Valley Authority
533	2010	12	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,791	Tennessee Valley Authority
534	2010	1	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	30,214	Tennessee Valley Authority
535	2010	9	1379	Shawnee	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,434	Tennessee Valley Authority
536	2010	7	6071	Trimble County	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL TRADE	32,958	Louisville Gas & Electric Co
537	2010	5	6071	Trimble County	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	29,554	Louisville Gas & Electric Co
538	2010	4	6071	Trimble County	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	19,596	Louisville Gas & Electric Co
539	2010	2	6071	Trimble County	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	16,557	Louisville Gas & Electric Co
540	2010	3	6071	Trimble County	KY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	16,438	Louisville Gas & Electric Co
541	2010	5	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	98,453	Louisiana Generating LLC
542	2010	6	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	98,354	Louisiana Generating LLC
543	2010	11	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	49,462	Louisiana Generating LLC
544	2010	5	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	J ARON	49,182	Louisiana Generating LLC
545	2010	4	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	32,811	Louisiana Generating LLC
546	2010	4	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	J ARON	32,792	Louisiana Generating LLC
547	2010	8	6055	Big Cajun 2	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	16,481	Louisiana Generating LLC
548	2010	3	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	43,351	Cleco Power LLC
549	2010	6	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	43,202	Cleco Power LLC
550	2010	12	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	29,108	Cleco Power LLC
551	2010	9	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	28,800	Cleco Power LLC
552	2010	2	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	28,732	Cleco Power LLC
553	2010	4	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	28,705	Cleco Power LLC
554	2010	10	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	28,645	Cleco Power LLC
555	2010	5	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	28,635	Cleco Power LLC
556	2010	11	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	14,612	Cleco Power LLC
557	2010	8	6190	Brame Energy Center	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	14,560	Cleco Power LLC
558	2010	8	1393	R S Nelson	LA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	43,848	Entergy Gulf States Louisiana LLC
559	2010	9	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	84,200	Constellation Power Source Gen
560	2010	5	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	78,665	Constellation Power Source Gen
561	2010	8	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	72,805	Constellation Power Source Gen
562	2010	10	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	57,088	Constellation Power Source Gen
563	2010	7	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	44,574	Constellation Power Source Gen
564	2010	12	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,426	Constellation Power Source Gen
565	2010	11	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,121	Constellation Power Source Gen
566	2010	4	1552	C P Crane	MD	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,240	Constellation Power Source Gen
567	2010	8	8841	BRSC Shared Storage	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	89,000	Detroit Edison Co
568	2010	7	8841	BRSC Shared Storage	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	65,000	Detroit Edison Co
569	2010	9	8841	BRSC Shared Storage	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	61,000	Detroit Edison Co
570	2010	11	8841	BRSC Shared Storage	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	21,000	Detroit Edison Co
571	2010	1	8841	BRSC Shared Storage	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,000	Detroit Edison Co
572	2010	5	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,030	Consumers Energy Co
573	2010	4	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	59,895	Consumers Energy Co
574	2010	10	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,596	Consumers Energy Co
575	2010	11	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,635	Consumers Energy Co
576	2010	11	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	15,948	Consumers Energy Co
577	2010	11	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,835	Consumers Energy Co
578	2010	7	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,815	Consumers Energy Co
579	2010	9	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ENSERCO	15,808	Consumers Energy Co
580	2010	8	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,805	Consumers Energy Co
581	2010	3	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,774	Consumers Energy Co

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582	2010	3	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,749	Consumers Energy Co
583	2010	2	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	15,748	Consumers Energy Co
584	2010	5	1702	Dan E Karn	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,654	Consumers Energy Co
585	2010	3	1720	J C Weadock	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,804	Consumers Energy Co
586	2010	4	1720	J C Weadock	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	3,043	Consumers Energy Co
587	2010	12	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	94,625	Consumers Energy Co
588	2010	11	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	79,069	Consumers Energy Co
589	2010	9	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,185	Consumers Energy Co
590	2010	12	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,113	Consumers Energy Co
591	2010	2	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	62,878	Consumers Energy Co
592	2010	3	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	62,500	Consumers Energy Co
593	2010	11	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	47,461	Consumers Energy Co
594	2010	7	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	47,434	Consumers Energy Co
595	2010	10	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,238	Consumers Energy Co
596	2010	8	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,040	Consumers Energy Co
597	2010	1	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	46,308	Consumers Energy Co
598	2010	10	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,934	Consumers Energy Co
599	2010	1	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	31,905	Consumers Energy Co
600	2010	6	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,688	Consumers Energy Co
601	2010	5	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,650	Consumers Energy Co
602	2010	11	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,642	Consumers Energy Co
603	2010	10	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,608	Consumers Energy Co
604	2010	4	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	31,564	Consumers Energy Co
605	2010	6	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,486	Consumers Energy Co
606	2010	1	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	31,280	Consumers Energy Co
607	2010	7	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,380	Consumers Energy Co
608	2010	4	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,903	Consumers Energy Co
609	2010	6	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,833	Consumers Energy Co
610	2010	7	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,830	Consumers Energy Co
611	2010	7	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,826	Consumers Energy Co
612	2010	5	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,819	Consumers Energy Co
613	2010	10	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	15,809	Consumers Energy Co
614	2010	5	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,802	Consumers Energy Co
615	2010	1	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,796	Consumers Energy Co
616	2010	11	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,785	Consumers Energy Co
617	2010	3	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,768	Consumers Energy Co
618	2010	11	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,765	Consumers Energy Co
619	2010	2	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,750	Consumers Energy Co
620	2010	8	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,690	Consumers Energy Co
621	2010	9	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	244	Consumers Energy Co
622	2010	1	1710	J H Campbell	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	243	Consumers Energy Co
623	2010	8	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	78,829	Consumers Energy Co
624	2010	6	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	62,672	Consumers Energy Co
625	2010	3	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	62,523	Consumers Energy Co
626	2010	12	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,023	Consumers Energy Co
627	2010	11	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,581	Consumers Energy Co
628	2010	4	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	31,555	Consumers Energy Co
629	2010	7	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,544	Consumers Energy Co
630	2010	9	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,448	Consumers Energy Co
631	2010	10	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,247	Consumers Energy Co
632	2010	1	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	30,710	Consumers Energy Co
633	2010	5	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,306	Consumers Energy Co
634	2010	10	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,942	Consumers Energy Co
635	2010	8	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,835	Consumers Energy Co
636	2010	8	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ENSERCO	15,803	Consumers Energy Co
637	2010	3	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	15,783	Consumers Energy Co
638	2010	12	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,774	Consumers Energy Co
639	2010	9	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ENSERCO	15,706	Consumers Energy Co
640	2010	1	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	15,679	Consumers Energy Co
641	2010	12	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,672	Consumers Energy Co
642	2010	6	1723	J R Whiting	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	122	Consumers Energy Co
643	2010	2	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	116,000	Detroit Edison Co
644	2010	11	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	85,000	Detroit Edison Co
645	2010	2	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ANTELOPE	76,000	Detroit Edison Co
646	2010	5	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	65,000	Detroit Edison Co
647	2010	11	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	63,000	Detroit Edison Co
648	2010	3	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	BLACK THUNDER WEST	46,000	Detroit Edison Co
649	2010	8	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	46,000	Detroit Edison Co
650	2010	7	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	37,000	Detroit Edison Co
651	2010	4	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	31,000	Detroit Edison Co
652	2010	12	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	31,000	Detroit Edison Co
653	2010	8	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	28,000	Detroit Edison Co
654	2010	10	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	28,000	Detroit Edison Co

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655	2010	6	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	26,000	Detroit Edison Co
656	2010	5	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,000	Detroit Edison Co
657	2010	7	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,000	Detroit Edison Co
658	2010	6	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,000	Detroit Edison Co
659	2010	6	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,000	Detroit Edison Co
660	2010	10	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,000	Detroit Edison Co
661	2010	9	1733	Monroe	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,000	Detroit Edison Co
662	2010	5	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	126,809	Wisconsin Electric Power Co
663	2010	12	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	123,714	Wisconsin Electric Power Co
664	2010	7	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	96,948	Wisconsin Electric Power Co
665	2010	6	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	95,571	Wisconsin Electric Power Co
666	2010	11	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	74,294	Wisconsin Electric Power Co
667	2010	9	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	72,661	Wisconsin Electric Power Co
668	2010	8	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,054	Wisconsin Electric Power Co
669	2010	10	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	40,490	Wisconsin Electric Power Co
670	2010	4	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	31,778	Wisconsin Electric Power Co
671	2010	1	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	31,625	Wisconsin Electric Power Co
672	2010	3	1769	Presque Isle	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	31,266	Wisconsin Electric Power Co
673	2010	8	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	44,000	Detroit Edison Co
674	2010	7	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	31,000	Detroit Edison Co
675	2010	4	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,000	Detroit Edison Co
676	2010	5	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ANTELOPE	16,000	Detroit Edison Co
677	2010	6	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,000	Detroit Edison Co
678	2010	9	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	16,000	Detroit Edison Co
679	2010	4	1740	River Rouge	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,000	Detroit Edison Co
680	2010	11	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	114,000	Detroit Edison Co
681	2010	12	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	98,000	Detroit Edison Co
682	2010	4	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	71,000	Detroit Edison Co
683	2010	9	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ANTELOPE	57,000	Detroit Edison Co
684	2010	7	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	44,000	Detroit Edison Co
685	2010	5	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	28,000	Detroit Edison Co
686	2010	10	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	28,000	Detroit Edison Co
687	2010	1	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,000	Detroit Edison Co
688	2010	6	1745	Trenton Channel	MI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,000	Detroit Edison Co
689	2010	5	1915	Allen S King	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	109	Northern States Power Co - Minnes
690	2010	4	1915	Allen S King	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	108	Northern States Power Co - Minnes
691	2010	9	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	61,587	Northern States Power Co - Minnes
692	2010	1	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	56,719	Northern States Power Co - Minnes
693	2010	11	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	48,749	Northern States Power Co - Minnes
694	2010	8	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	36,280	Northern States Power Co - Minnes
695	2010	8	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	36,204	Northern States Power Co - Minnes
696	2010	6	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	36,017	Northern States Power Co - Minnes
697	2010	4	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	35,855	Northern States Power Co - Minnes
698	2010	4	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	35,786	Northern States Power Co - Minnes
699	2010	7	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	35,706	Northern States Power Co - Minnes
700	2010	2	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	34,403	Northern States Power Co - Minnes
701	2010	2	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	33,268	Northern States Power Co - Minnes
702	2010	12	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,153	Northern States Power Co - Minnes
703	2010	7	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,089	Northern States Power Co - Minnes
704	2010	4	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,043	Northern States Power Co - Minnes
705	2010	7	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,005	Northern States Power Co - Minnes
706	2010	9	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	23,880	Northern States Power Co - Minnes
707	2010	6	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	23,869	Northern States Power Co - Minnes
708	2010	1	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	21,614	Northern States Power Co - Minnes
709	2010	10	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	12,219	Northern States Power Co - Minnes
710	2010	10	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	12,192	Northern States Power Co - Minnes
711	2010	7	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	12,081	Northern States Power Co - Minnes
712	2010	12	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	12,052	Northern States Power Co - Minnes
713	2010	5	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	12,045	Northern States Power Co - Minnes
714	2010	6	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	12,002	Northern States Power Co - Minnes
715	2010	8	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	11,993	Northern States Power Co - Minnes
716	2010	6	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	11,909	Northern States Power Co - Minnes
717	2010	5	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	11,886	Northern States Power Co - Minnes
718	2010	3	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	10,943	Northern States Power Co - Minnes
719	2010	3	1904	Black Dog	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	10,769	Northern States Power Co - Minnes
720	2010	3	1893	Clay Boswell	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	142,624	Minnesota Power Inc
721	2010	6	1893	Clay Boswell	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	42,308	Minnesota Power Inc
722	2010	8	1893	Clay Boswell	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	41,943	Minnesota Power Inc
723	2010	9	1893	Clay Boswell	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	28,614	Minnesota Power Inc
724	2010	8	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	83,617	Northern States Power Co - Minnes
725	2010	7	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	57,816	Northern States Power Co - Minnes
726	2010	5	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	56,137	Northern States Power Co - Minnes
727	2010	7	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	55,561	Northern States Power Co - Minnes

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728	2010	3	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	40,756	Northern States Power Co - Minnes
729	2010	6	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	28,420	Northern States Power Co - Minnes
730	2010	5	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	28,023	Northern States Power Co - Minnes
731	2010	7	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,937	Northern States Power Co - Minnes
732	2010	8	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,842	Northern States Power Co - Minnes
733	2010	6	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,669	Northern States Power Co - Minnes
734	2010	5	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,549	Northern States Power Co - Minnes
735	2010	12	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	25,491	Northern States Power Co - Minnes
736	2010	9	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	14,201	Northern States Power Co - Minnes
737	2010	5	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	14,186	Northern States Power Co - Minnes
738	2010	9	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	14,072	Northern States Power Co - Minnes
739	2010	8	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,963	Northern States Power Co - Minnes
740	2010	3	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,962	Northern States Power Co - Minnes
741	2010	7	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,962	Northern States Power Co - Minnes
742	2010	3	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,961	Northern States Power Co - Minnes
743	2010	6	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,954	Northern States Power Co - Minnes
744	2010	4	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,449	Northern States Power Co - Minnes
745	2010	12	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	12,755	Northern States Power Co - Minnes
746	2010	4	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	486	Northern States Power Co - Minnes
747	2010	6	6090	Sherburne County	MN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	122	Northern States Power Co - Minnes
748	2010	8	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	35,519	Empire District Electric Co
749	2010	4	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	21,150	Empire District Electric Co
750	2010	5	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,775	Empire District Electric Co
751	2010	2	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,647	Empire District Electric Co
752	2010	10	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,411	Empire District Electric Co
753	2010	3	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,408	Empire District Electric Co
754	2010	7	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,239	Empire District Electric Co
755	2010	11	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,175	Empire District Electric Co
756	2010	6	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	9,795	Empire District Electric Co
757	2010	9	2076	Asbury	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	8,234	Empire District Electric Co
758	2010	1	2079	Hawthorn	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	31,744	Kansas City Power & Light Co
759	2010	5	2079	Hawthorn	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	16,111	Kansas City Power & Light Co
760	2010	2	2079	Hawthorn	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	363	Kansas City Power & Light Co
761	2010	2	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	50,253	Union Electric Co
762	2010	1	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	49,184	Union Electric Co
763	2010	12	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,408	Union Electric Co
764	2010	6	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,302	Union Electric Co
765	2010	3	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,660	Union Electric Co
766	2010	8	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,846	Union Electric Co
767	2010	2	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,797	Union Electric Co
768	2010	8	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,755	Union Electric Co
769	2010	3	2103	Labadie	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,614	Union Electric Co
770	2010	1	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	78,197	Union Electric Co
771	2010	4	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,298	Union Electric Co
772	2010	3	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	63,064	Union Electric Co
773	2010	2	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	62,598	Union Electric Co
774	2010	9	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,336	Union Electric Co
775	2010	7	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,705	Union Electric Co
776	2010	6	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,696	Union Electric Co
777	2010	10	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,657	Union Electric Co
778	2010	10	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,584	Union Electric Co
779	2010	12	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,546	Union Electric Co
780	2010	4	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,532	Union Electric Co
781	2010	3	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,525	Union Electric Co
782	2010	12	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,498	Union Electric Co
783	2010	7	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,469	Union Electric Co
784	2010	12	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,469	Union Electric Co
785	2010	4	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,362	Union Electric Co
786	2010	11	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,353	Union Electric Co
787	2010	6	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,300	Union Electric Co
788	2010	5	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,192	Union Electric Co
789	2010	4	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,910	Union Electric Co
790	2010	8	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,886	Union Electric Co
791	2010	8	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,877	Union Electric Co
792	2010	8	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,872	Union Electric Co
793	2010	8	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,868	Union Electric Co
794	2010	3	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,790	Union Electric Co
795	2010	5	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,774	Union Electric Co
796	2010	4	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,737	Union Electric Co
797	2010	5	2104	Meramec	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,710	Union Electric Co
798	2010	11	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,681	Kansas City Power & Light Co
799	2010	10	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,662	Kansas City Power & Light Co
800	2010	7	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,645	Kansas City Power & Light Co

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801	2010	8	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,485	Kansas City Power & Light Co
802	2010	5	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,422	Kansas City Power & Light Co
803	2010	12	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,293	Kansas City Power & Light Co
804	2010	4	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,247	Kansas City Power & Light Co
805	2010	2	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,184	Kansas City Power & Light Co
806	2010	9	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,102	Kansas City Power & Light Co
807	2010	6	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,093	Kansas City Power & Light Co
808	2010	3	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	30,015	Kansas City Power & Light Co
809	2010	1	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	JP MORGAN	28,847	Kansas City Power & Light Co
810	2010	10	2080	Montrose	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,336	Kansas City Power & Light Co
811	2010	7	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	458,534	Associated Electric Coop, Inc
812	2010	2	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	457,786	Associated Electric Coop, Inc
813	2010	3	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	430,693	Associated Electric Coop, Inc
814	2010	8	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	412,615	Associated Electric Coop, Inc
815	2010	9	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	412,546	Associated Electric Coop, Inc
816	2010	11	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	397,274	Associated Electric Coop, Inc
817	2010	1	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	340,303	Associated Electric Coop, Inc
818	2010	6	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	336,117	Associated Electric Coop, Inc
819	2010	12	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	334,696	Associated Electric Coop, Inc
820	2010	5	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	291,420	Associated Electric Coop, Inc
821	2010	10	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	261,187	Associated Electric Coop, Inc
822	2010	4	2167	New Madrid	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	237,584	Associated Electric Coop, Inc
823	2010	3	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	140,811	Union Electric Co
824	2010	2	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	123,540	Union Electric Co
825	2010	1	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	122,503	Union Electric Co
826	2010	4	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	111,371	Union Electric Co
827	2010	7	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	109,316	Union Electric Co
828	2010	9	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	108,963	Union Electric Co
829	2010	5	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	93,135	Union Electric Co
830	2010	6	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	91,572	Union Electric Co
831	2010	11	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	79,833	Union Electric Co
832	2010	12	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	79,328	Union Electric Co
833	2010	8	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	46,520	Union Electric Co
834	2010	10	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,771	Union Electric Co
835	2010	10	2107	Sioux	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,721	Union Electric Co
836	2010	5	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	467,915	Associated Electric Coop, Inc
837	2010	4	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	433,343	Associated Electric Coop, Inc
838	2010	12	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	423,957	Associated Electric Coop, Inc
839	2010	7	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	415,740	Associated Electric Coop, Inc
840	2010	1	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	381,916	Associated Electric Coop, Inc
841	2010	10	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	377,454	Associated Electric Coop, Inc
842	2010	2	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	358,881	Associated Electric Coop, Inc
843	2010	3	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	338,368	Associated Electric Coop, Inc
844	2010	9	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	337,291	Associated Electric Coop, Inc
845	2010	6	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	322,648	Associated Electric Coop, Inc
846	2010	11	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	305,461	Associated Electric Coop, Inc
847	2010	8	2168	Thomas Hill	MO	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	287,065	Associated Electric Coop, Inc
848	2010	1	6073	Victor J Daniel Jr	MS	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	27,932	Mississippi Power Co
849	2010	6	6077	Gerald Gentleman	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	EDF TRADING	14,586	Nebraska Public Power District
850	2010	1	6077	Gerald Gentleman	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	EDF TRADING	14,412	Nebraska Public Power District
851	2010	3	6077	Gerald Gentleman	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	EDF TRADING	14,402	Nebraska Public Power District
852	2010	5	6077	Gerald Gentleman	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	EDF TRADING	14,398	Nebraska Public Power District
853	2010	4	6077	Gerald Gentleman	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	EDF TRADING	14,389	Nebraska Public Power District
854	2010	9	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	191,488	Omaha Public Power District
855	2010	5	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	172,998	Omaha Public Power District
856	2010	8	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	143,136	Omaha Public Power District
857	2010	3	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	127,312	Omaha Public Power District
858	2010	12	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	125,978	Omaha Public Power District
859	2010	6	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	94,872	Omaha Public Power District
860	2010	7	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	94,788	Omaha Public Power District
861	2010	12	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	79,217	Omaha Public Power District
862	2010	10	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,858	Omaha Public Power District
863	2010	11	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,579	Omaha Public Power District
864	2010	8	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,266	Omaha Public Power District
865	2010	6	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,264	Omaha Public Power District
866	2010	7	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,135	Omaha Public Power District
867	2010	11	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,723	Omaha Public Power District
868	2010	9	6096	Nebraska City	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	31,489	Omaha Public Power District
869	2010	4	2291	North Omaha	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	63,015	Omaha Public Power District
870	2010	6	2291	North Omaha	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,667	Omaha Public Power District
871	2010	3	2291	North Omaha	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	47,637	Omaha Public Power District
872	2010	1	2291	North Omaha	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	15,901	Omaha Public Power District
873	2010	12	2291	North Omaha	NE	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,889	Omaha Public Power District

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
874	2010	10	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	55,157	NRG Huntley Operations Inc
875	2010	9	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	36,042	NRG Huntley Operations Inc
876	2010	7	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	30,522	NRG Huntley Operations Inc
877	2010	3	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	30,490	NRG Huntley Operations Inc
878	2010	4	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,866	NRG Huntley Operations Inc
879	2010	2	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,337	NRG Huntley Operations Inc
880	2010	3	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,880	NRG Huntley Operations Inc
881	2010	10	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,409	NRG Huntley Operations Inc
882	2010	10	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,378	NRG Huntley Operations Inc
883	2010	8	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,348	NRG Huntley Operations Inc
884	2010	11	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,230	NRG Huntley Operations Inc
885	2010	8	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,229	NRG Huntley Operations Inc
886	2010	11	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,203	NRG Huntley Operations Inc
887	2010	2	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,153	NRG Huntley Operations Inc
888	2010	2	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,144	NRG Huntley Operations Inc
889	2010	7	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,609	NRG Huntley Operations Inc
890	2010	1	2549	C R Huntley Generating St	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	1,941	NRG Huntley Operations Inc
891	2010	9	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	85,824	Dunkirk Power LLC
892	2010	2	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	61,775	Dunkirk Power LLC
893	2010	7	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,672	Dunkirk Power LLC
894	2010	8	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	53,331	Dunkirk Power LLC
895	2010	11	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	41,028	Dunkirk Power LLC
896	2010	12	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	35,042	Dunkirk Power LLC
897	2010	3	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	30,056	Dunkirk Power LLC
898	2010	7	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,816	Dunkirk Power LLC
899	2010	2	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,719	Dunkirk Power LLC
900	2010	1	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	26,739	Dunkirk Power LLC
901	2010	8	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,324	Dunkirk Power LLC
902	2010	11	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,224	Dunkirk Power LLC
903	2010	8	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,223	Dunkirk Power LLC
904	2010	10	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,218	Dunkirk Power LLC
905	2010	3	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,204	Dunkirk Power LLC
906	2010	3	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,197	Dunkirk Power LLC
907	2010	3	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,160	Dunkirk Power LLC
908	2010	3	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,141	Dunkirk Power LLC
909	2010	9	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,129	Dunkirk Power LLC
910	2010	12	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,078	Dunkirk Power LLC
911	2010	2	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,077	Dunkirk Power LLC
912	2010	11	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,065	Dunkirk Power LLC
913	2010	3	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,063	Dunkirk Power LLC
914	2010	4	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,049	Dunkirk Power LLC
915	2010	7	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,984	Dunkirk Power LLC
916	2010	8	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,874	Dunkirk Power LLC
917	2010	1	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,856	Dunkirk Power LLC
918	2010	4	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,764	Dunkirk Power LLC
919	2010	7	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,660	Dunkirk Power LLC
920	2010	7	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,636	Dunkirk Power LLC
921	2010	12	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,571	Dunkirk Power LLC
922	2010	1	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,401	Dunkirk Power LLC
923	2010	4	2554	Dunkirk Generating Plant	NY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	118	Dunkirk Power LLC
924	2010	4	2835	Ashtabula	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	28,633	FirstEnergy Generation Corp
925	2010	11	2828	Cardinal	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	33,707	Cardinal Operating Co
926	2010	10	2828	Cardinal	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	17,057	Cardinal Operating Co
927	2010	3	2837	Eastlake	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	15,336	FirstEnergy Generation Corp
928	2010	1	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	176,687	Ohio Power Co
929	2010	5	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	123,377	Ohio Power Co
930	2010	6	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	115,184	Ohio Power Co
931	2010	7	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	115,072	Ohio Power Co
932	2010	11	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	114,900	Ohio Power Co
933	2010	10	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	114,797	Ohio Power Co
934	2010	4	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	114,747	Ohio Power Co
935	2010	8	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	98,353	Ohio Power Co
936	2010	3	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	82,652	Ohio Power Co
937	2010	9	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	67,581	Ohio Power Co
938	2010	9	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	67,197	Ohio Power Co
939	2010	3	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	65,487	Ohio Power Co
940	2010	4	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	41,463	Ohio Power Co
941	2010	7	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	33,075	Ohio Power Co
942	2010	10	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	33,014	Ohio Power Co
943	2010	5	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	32,781	Ohio Power Co
944	2010	2	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	32,661	Ohio Power Co
945	2010	4	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	18,311	Ohio Power Co
946	2010	4	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	16,502	Ohio Power Co

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947	2010	8	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,479	Ohio Power Co
948	2010	11	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,382	Ohio Power Co
949	2010	6	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,381	Ohio Power Co
950	2010	3	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	16,376	Ohio Power Co
951	2010	3	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	13,707	Ohio Power Co
952	2010	4	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	12,895	Ohio Power Co
953	2010	5	8102	General James M Gavin	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	4,848	Ohio Power Co
954	2010	1	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	236,651	Ohio Valley Electric Corp
955	2010	10	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	189,810	Ohio Valley Electric Corp
956	2010	12	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	153,729	Ohio Valley Electric Corp
957	2010	2	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	153,020	Ohio Valley Electric Corp
958	2010	7	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	137,966	Ohio Valley Electric Corp
959	2010	8	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	121,335	Ohio Valley Electric Corp
960	2010	9	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	120,422	Ohio Valley Electric Corp
961	2010	3	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	119,714	Ohio Valley Electric Corp
962	2010	11	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	103,297	Ohio Valley Electric Corp
963	2010	6	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	102,984	Ohio Valley Electric Corp
964	2010	5	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	69,150	Ohio Valley Electric Corp
965	2010	4	2876	Kyger Creek	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	69,123	Ohio Valley Electric Corp
966	2010	5	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	105,226	FirstEnergy Generation Corp
967	2010	1	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	87,158	FirstEnergy Generation Corp
968	2010	3	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	75,103	FirstEnergy Generation Corp
969	2010	2	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	74,775	FirstEnergy Generation Corp
970	2010	4	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL	61,318	FirstEnergy Generation Corp
971	2010	7	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	30,315	FirstEnergy Generation Corp
972	2010	6	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,347	FirstEnergy Generation Corp
973	2010	1	2866	W H Sammis	OH	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CAMELOT	15,314	FirstEnergy Generation Corp
974	2010	4	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	162,236	Oklahoma Gas & Electric Co
975	2010	3	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	130,561	Oklahoma Gas & Electric Co
976	2010	10	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	114,986	Oklahoma Gas & Electric Co
977	2010	11	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	114,933	Oklahoma Gas & Electric Co
978	2010	9	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	114,830	Oklahoma Gas & Electric Co
979	2010	2	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	113,526	Oklahoma Gas & Electric Co
980	2010	7	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	97,958	Oklahoma Gas & Electric Co
981	2010	5	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	97,917	Oklahoma Gas & Electric Co
982	2010	1	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	94,633	Oklahoma Gas & Electric Co
983	2010	6	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	81,631	Oklahoma Gas & Electric Co
984	2010	12	2952	Muskogee	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	48,784	Oklahoma Gas & Electric Co
985	2010	1	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	75,376	Public Service Co of Oklahoma
986	2010	10	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	60,693	Public Service Co of Oklahoma
987	2010	5	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	45,705	Public Service Co of Oklahoma
988	2010	12	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	45,310	Public Service Co of Oklahoma
989	2010	6	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	45,232	Public Service Co of Oklahoma
990	2010	2	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	44,762	Public Service Co of Oklahoma
991	2010	8	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	30,389	Public Service Co of Oklahoma
992	2010	4	2963	Northeastern	OK	SUB	Coal	Su	WY	5	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	30,118	Public Service Co of Oklahoma
993	2010	11	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	30,053	Public Service Co of Oklahoma
994	2010	7	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	15,305	Public Service Co of Oklahoma
995	2010	9	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	15,159	Public Service Co of Oklahoma
996	2010	3	2963	Northeastern	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	15,044	Public Service Co of Oklahoma
997	2010	5	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	126,472	Oklahoma Gas & Electric Co
998	2010	10	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	107,401	Oklahoma Gas & Electric Co
999	2010	4	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	90,823	Oklahoma Gas & Electric Co
1000	2010	9	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	90,599	Oklahoma Gas & Electric Co
1001	2010	11	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	90,365	Oklahoma Gas & Electric Co
1002	2010	6	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	90,117	Oklahoma Gas & Electric Co
1003	2010	8	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	83,498	Oklahoma Gas & Electric Co
1004	2010	1	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	70,797	Oklahoma Gas & Electric Co
1005	2010	12	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	70,509	Oklahoma Gas & Electric Co
1006	2010	7	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	36,303	Oklahoma Gas & Electric Co
1007	2010	3	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	35,444	Oklahoma Gas & Electric Co
1008	2010	2	6095	Sooner	OK	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	18,013	Oklahoma Gas & Electric Co
1009	2010	7	3179	Hatfields Ferry Power Stati	PA	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	2,883	Allegheny Energy Supply Co LLC
1010	2010	3	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	196,039	Tennessee Valley Authority
1011	2010	4	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	193,552	Tennessee Valley Authority
1012	2010	10	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	187,554	Tennessee Valley Authority
1013	2010	9	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	173,971	Tennessee Valley Authority
1014	2010	12	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	166,181	Tennessee Valley Authority
1015	2010	8	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	156,765	Tennessee Valley Authority
1016	2010	1	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	155,313	Tennessee Valley Authority
1017	2010	2	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	154,572	Tennessee Valley Authority
1018	2010	5	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	153,053	Tennessee Valley Authority
1019	2010	11	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	139,436	Tennessee Valley Authority

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1020	2010	6	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	94,777	Tennessee Valley Authority
1021	2010	7	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	63,936	Tennessee Valley Authority
1022	2010	7	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	57,868	Tennessee Valley Authority
1023	2010	2	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	38,120	Tennessee Valley Authority
1024	2010	1	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	34,100	Tennessee Valley Authority
1025	2010	6	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,559	Tennessee Valley Authority
1026	2010	7	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,261	Tennessee Valley Authority
1027	2010	6	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	24,928	Tennessee Valley Authority
1028	2010	3	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	13,714	Tennessee Valley Authority
1029	2010	1	3393	Allen Steam Plant	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	2,718	Tennessee Valley Authority
1030	2010	6	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	107,961	Tennessee Valley Authority
1031	2010	4	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	49,195	Tennessee Valley Authority
1032	2010	6	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	44,591	Tennessee Valley Authority
1033	2010	8	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	38,730	Tennessee Valley Authority
1034	2010	3	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	38,680	Tennessee Valley Authority
1035	2010	7	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL TRADE	38,138	Tennessee Valley Authority
1036	2010	3	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	33,114	Tennessee Valley Authority
1037	2010	1	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALTRADE	32,944	Tennessee Valley Authority
1038	2010	5	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	31,075	Tennessee Valley Authority
1039	2010	12	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	30,684	Tennessee Valley Authority
1040	2010	7	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	29,202	Tennessee Valley Authority
1041	2010	1	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	28,785	Tennessee Valley Authority
1042	2010	4	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	23,021	Tennessee Valley Authority
1043	2010	9	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	22,924	Tennessee Valley Authority
1044	2010	11	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	20,624	Tennessee Valley Authority
1045	2010	6	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL TRADE	20,405	Tennessee Valley Authority
1046	2010	2	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	POWDER RIVER	19,376	Tennessee Valley Authority
1047	2010	1	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	18,112	Tennessee Valley Authority
1048	2010	11	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL TRADE	16,413	Tennessee Valley Authority
1049	2010	7	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,712	Tennessee Valley Authority
1050	2010	5	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL TRADE	12,116	Tennessee Valley Authority
1051	2010	7	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	11,755	Tennessee Valley Authority
1052	2010	8	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL TRADE	11,202	Tennessee Valley Authority
1053	2010	2	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	8,424	Tennessee Valley Authority
1054	2010	3	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	7,907	Tennessee Valley Authority
1055	2010	2	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	2,005	Tennessee Valley Authority
1056	2010	8	3403	Gallatin	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	1,237	Tennessee Valley Authority
1057	2010	6	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	131,137	Tennessee Valley Authority
1058	2010	7	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	84,042	Tennessee Valley Authority
1059	2010	12	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	77,731	Tennessee Valley Authority
1060	2010	3	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	54,128	Tennessee Valley Authority
1061	2010	8	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	34,350	Tennessee Valley Authority
1062	2010	2	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	25,981	Tennessee Valley Authority
1063	2010	5	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COAL SALES	25,097	Tennessee Valley Authority
1064	2010	1	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	18,618	Tennessee Valley Authority
1065	2010	9	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	10,675	Tennessee Valley Authority
1066	2010	3	3406	Johnsonville	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	325	Tennessee Valley Authority
1067	2010	7	3407	Kingston	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	15,326	Tennessee Valley Authority
1068	2010	8	3407	Kingston	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	785	Tennessee Valley Authority
1069	2010	9	3407	Kingston	TN	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	466	Tennessee Valley Authority
1070	2010	4	6178	Coleto Creek	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK ENERGY RESOURC	82,065	Coleto Creek Power LP
1071	2010	5	6178	Coleto Creek	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK ENERGY RESOURC	16,461	Coleto Creek Power LP
1072	2010	6	6178	Coleto Creek	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK ENERGY RESOURC	16,414	Coleto Creek Power LP
1073	2010	7	6178	Coleto Creek	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	CLOUD PEAK ENERGY RESOURC	16,264	Coleto Creek Power LP
1074	2010	12	6179	Fayette Power Project	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	92,841	Lower Colorado River Authority
1075	2010	11	6179	Fayette Power Project	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,345	Lower Colorado River Authority
1076	2010	9	6179	Fayette Power Project	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	33,069	Lower Colorado River Authority
1077	2010	8	6179	Fayette Power Project	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,970	Lower Colorado River Authority
1078	2010	7	6179	Fayette Power Project	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,917	Lower Colorado River Authority
1079	2010	10	6179	Fayette Power Project	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	32,896	Lower Colorado River Authority
1080	2010	1	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	128,601	NRG Texas Power LLC
1081	2010	7	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	116,793	NRG Texas Power LLC
1082	2010	4	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	73,038	NRG Texas Power LLC
1083	2010	5	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,362	NRG Texas Power LLC
1084	2010	2	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,355	NRG Texas Power LLC
1085	2010	6	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,164	NRG Texas Power LLC
1086	2010	3	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	57,275	NRG Texas Power LLC
1087	2010	10	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	43,925	NRG Texas Power LLC
1088	2010	9	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,292	NRG Texas Power LLC
1089	2010	5	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,274	NRG Texas Power LLC
1090	2010	12	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,778	NRG Texas Power LLC
1091	2010	5	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,675	NRG Texas Power LLC
1092	2010	8	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,663	NRG Texas Power LLC

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1093	2010	9	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,662	NRG Texas Power LLC
1094	2010	6	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,658	NRG Texas Power LLC
1095	2010	3	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,656	NRG Texas Power LLC
1096	2010	3	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,654	NRG Texas Power LLC
1097	2010	7	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,648	NRG Texas Power LLC
1098	2010	11	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,637	NRG Texas Power LLC
1099	2010	11	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,635	NRG Texas Power LLC
1100	2010	6	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,633	NRG Texas Power LLC
1101	2010	2	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,625	NRG Texas Power LLC
1102	2010	12	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,625	NRG Texas Power LLC
1103	2010	9	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,612	NRG Texas Power LLC
1104	2010	10	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,590	NRG Texas Power LLC
1105	2010	1	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,546	NRG Texas Power LLC
1106	2010	10	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,471	NRG Texas Power LLC
1107	2010	8	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,162	NRG Texas Power LLC
1108	2010	4	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	13,795	NRG Texas Power LLC
1109	2010	2	298	Limestone	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	123	NRG Texas Power LLC
1110	2010	7	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	43,554	Public Service Co of Oklahoma
1111	2010	10	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	29,190	Public Service Co of Oklahoma
1112	2010	8	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	29,093	Public Service Co of Oklahoma
1113	2010	7	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	29,091	Public Service Co of Oklahoma
1114	2010	9	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	28,901	Public Service Co of Oklahoma
1115	2010	8	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	28,858	Public Service Co of Oklahoma
1116	2010	12	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	28,800	Public Service Co of Oklahoma
1117	2010	11	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	28,628	Public Service Co of Oklahoma
1118	2010	9	127	Oklaunion	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	14,544	Public Service Co of Oklahoma
1119	2010	10	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	145,999	NRG Texas Power LLC
1120	2010	5	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	102,299	NRG Texas Power LLC
1121	2010	12	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	101,829	NRG Texas Power LLC
1122	2010	11	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,725	NRG Texas Power LLC
1123	2010	4	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,419	NRG Texas Power LLC
1124	2010	7	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	58,043	NRG Texas Power LLC
1125	2010	8	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	43,902	NRG Texas Power LLC
1126	2010	6	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	43,872	NRG Texas Power LLC
1127	2010	12	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COMPLEX	41,763	NRG Texas Power LLC
1128	2010	2	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,274	NRG Texas Power LLC
1129	2010	1	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	29,021	NRG Texas Power LLC
1130	2010	7	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,646	NRG Texas Power LLC
1131	2010	9	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,598	NRG Texas Power LLC
1132	2010	1	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,375	NRG Texas Power LLC
1133	2010	3	3470	W A Parish	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	14,284	NRG Texas Power LLC
1134	2010	8	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	320,117	Southwestern Electric Power Co
1135	2010	7	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	318,489	Southwestern Electric Power Co
1136	2010	5	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	303,854	Southwestern Electric Power Co
1137	2010	10	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	303,381	Southwestern Electric Power Co
1138	2010	12	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	271,822	Southwestern Electric Power Co
1139	2010	3	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	256,660	Southwestern Electric Power Co
1140	2010	1	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	253,266	Southwestern Electric Power Co
1141	2010	9	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	242,220	Southwestern Electric Power Co
1142	2010	11	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	212,622	Southwestern Electric Power Co
1143	2010	2	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	211,658	Southwestern Electric Power Co
1144	2010	4	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	166,443	Southwestern Electric Power Co
1145	2010	6	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	164,278	Southwestern Electric Power Co
1146	2010	4	6139	Welsh	TX	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	30,524	Southwestern Electric Power Co
1147	2010	6	4143	Genoa	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	28,300	Dairyland Power Coop
1148	2010	7	4143	Genoa	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	19,431	Dairyland Power Coop
1149	2010	8	4143	Genoa	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	18,530	Dairyland Power Coop
1150	2010	9	4143	Genoa	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	15,891	Dairyland Power Coop
1151	2010	10	4143	Genoa	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	13,235	Dairyland Power Coop
1152	2010	11	4143	Genoa	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	1,500	Dairyland Power Coop
1153	2010	4	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	149,651	Dairyland Power Coop
1154	2010	3	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	145,209	Dairyland Power Coop
1155	2010	12	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	139,935	Dairyland Power Coop
1156	2010	7	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	133,832	Dairyland Power Coop
1157	2010	2	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	125,060	Dairyland Power Coop
1158	2010	1	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	119,569	Dairyland Power Coop
1159	2010	8	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	115,434	Dairyland Power Coop
1160	2010	6	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	103,913	Dairyland Power Coop
1161	2010	5	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	88,873	Dairyland Power Coop
1162	2010	10	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	87,848	Dairyland Power Coop
1163	2010	11	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	82,946	Dairyland Power Coop
1164	2010	9	4271	John P Madgett	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NORTH ANTELOPE	72,031	Dairyland Power Coop
1165	2010	4	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	81,642	Wisconsin Public Service Corp

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1166	2010	6	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	54,279	Wisconsin Public Service Corp
1167	2010	7	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	54,211	Wisconsin Public Service Corp
1168	2010	5	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	54,113	Wisconsin Public Service Corp
1169	2010	8	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	40,897	Wisconsin Public Service Corp
1170	2010	10	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	40,804	Wisconsin Public Service Corp
1171	2010	3	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	40,707	Wisconsin Public Service Corp
1172	2010	2	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	40,586	Wisconsin Public Service Corp
1173	2010	1	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	39,650	Wisconsin Public Service Corp
1174	2010	11	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	27,019	Wisconsin Public Service Corp
1175	2010	12	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	26,821	Wisconsin Public Service Corp
1176	2010	9	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	25,883	Wisconsin Public Service Corp
1177	2010	6	4072	Pulliam	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NRG	13,602	Wisconsin Public Service Corp
1178	2010	10	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	327,382	Wisconsin Electric Power Co
1179	2010	2	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	273,025	Wisconsin Electric Power Co
1180	2010	3	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	260,689	Wisconsin Electric Power Co
1181	2010	4	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	257,705	Wisconsin Electric Power Co
1182	2010	11	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	257,332	Wisconsin Electric Power Co
1183	2010	12	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	247,546	Wisconsin Electric Power Co
1184	2010	1	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	235,831	Wisconsin Electric Power Co
1185	2010	8	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	229,357	Wisconsin Electric Power Co
1186	2010	9	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	228,048	Wisconsin Electric Power Co
1187	2010	5	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY	196,954	Wisconsin Electric Power Co
1188	2010	7	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	163,953	Wisconsin Electric Power Co
1189	2010	6	4041	South Oak Creek	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	163,845	Wisconsin Electric Power Co
1190	2010	11	4078	Weston	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	47,637	Wisconsin Public Service Corp
1191	2010	10	4078	Weston	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	16,444	Wisconsin Public Service Corp
1192	2010	7	4078	Weston	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NRG	16,421	Wisconsin Public Service Corp
1193	2010	6	4078	Weston	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	NRG	13,915	Wisconsin Public Service Corp
1194	2010	9	4078	Weston	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	13,740	Wisconsin Public Service Corp
1195	2010	1	4078	Weston	WI	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES LLC	121	Wisconsin Public Service Corp
1196	2010	7	3943	Fort Martin Power Station	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	28,290	Monongahela Power Co
1197	2010	7	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	49,430	Ohio Power Co
1198	2010	3	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	42,042	Ohio Power Co
1199	2010	2	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	24,924	Ohio Power Co
1200	2010	11	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,503	Ohio Power Co
1201	2010	5	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,406	Ohio Power Co
1202	2010	1	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	16,135	Ohio Power Co
1203	2010	8	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	16,113	Ohio Power Co
1204	2010	1	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	16,002	Ohio Power Co
1205	2010	6	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	13,725	Ohio Power Co
1206	2010	5	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COALSALES	8,239	Ohio Power Co
1207	2010	4	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	Peabody COALSALES	7,874	Ohio Power Co
1208	2010	3	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	COALSALES	7,309	Ohio Power Co
1209	2010	9	3947	Kammer	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	OPCO	1,493	Ohio Power Co
1210	2010	7	3946	Willow Island	WV	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	ARCH	6,169	Monongahela Power Co
1211	2010	11	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	213,490	Basin Electric Power Coop
1212	2010	8	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	148,350	Basin Electric Power Coop
1213	2010	10	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	132,053	Basin Electric Power Coop
1214	2010	4	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	115,701	Basin Electric Power Coop
1215	2010	12	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	98,415	Basin Electric Power Coop
1216	2010	7	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	82,766	Basin Electric Power Coop
1217	2010	6	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	82,376	Basin Electric Power Coop
1218	2010	3	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	82,260	Basin Electric Power Coop
1219	2010	9	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,648	Basin Electric Power Coop
1220	2010	5	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,546	Basin Electric Power Coop
1221	2010	2	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,329	Basin Electric Power Coop
1222	2010	1	6204	Laramie River Station	WY	SUB	Coal	S	WY	005	NORTH ANTELOPE ROCHELLE MINE	PEABODY COAL SALES	49,195	Basin Electric Power Coop

Exhibit 7

Hong, B.D. and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," EIA, *Quarterly Coal Report, January—April 1994*, DOE/EIA-0121 (94/Q1) (Aug. 1994)

Carbon Dioxide Emission Factors for Coal

by

B.D. Hong and E. R. Slatick

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Introduction

Coal is an important source of energy in the United States, and the Nation's reliance on this fossil fuel for electricity generation is growing. The combustion of coal, however, adds a significant amount of carbon dioxide to the atmosphere per unit of heat energy, more than does the combustion of other fossil fuels.(1) Because of a growing concern over the possible consequences of global warming, which may be caused in part by increases in atmospheric carbon dioxide (a major greenhouse gas), and also because of the need for accurate estimates of carbon dioxide emissions, the Energy Information Administration (EIA) has developed factors for estimating the amount of carbon dioxide emitted as a result of U.S. coal consumption.

Carbon dioxide emission factors for U.S. coals have previously been available from several sources. However, those emission factors have shortcomings because they are based on analyses of only a few coal samples. Most are single factors applied to all coals, regardless of rank (i.e., whether anthracite, bituminous, subbituminous, or lignite) or geographic origin. Because single factors do not account for differences among coals, they fail to reflect the changing "mix" of coal in U.S. coal consumption that has occurred in the past and will occur in the future. Lacking standardization, the factors previously available also differ widely from each other.(2)

EIA's emission factors will improve the accuracy of estimates of carbon dioxide emissions, especially at State and regional levels, because they reflect the difference in the ratio of carbon to heat content by rank of coal and State of origin. EIA's emission factors are derived from the EIA Coal Analysis File, a large database of coal sample analyses. The emission factors vary significantly by coal rank, confirming a long-recognized finding, and also within each rank by State of origin. These findings were verified statistically.

Two types of carbon dioxide emission factors have been developed. First are basic emission factors covering the various coal ranks by State of origin. These basic emission factors are considered as "fixed" for the foreseeable future until better data become available. Second are emission factors for use in estimating carbon dioxide emissions from coal consumption by State, with consuming-sector detail. These emission factors are based on the mix of coal consumed and the basic emission factors by coal rank and State of origin. These emission factors are subject to change over time, reflecting changes in the mix of coal consumed.

EIA's emission factors will not only enable coal-generated carbon dioxide emissions to be estimated more accurately than before, but they will also provide consistency in estimates. Energy and environmental analysts will find EIA's emission factors useful for analyzing and monitoring carbon dioxide emissions from coal combustion, whether they are estimated by the State of origin of the coal, consuming State, or consuming sector.

Coal Combustion and Carbon Dioxide Emissions

The amount of heat emitted during coal combustion depends largely on the amounts of carbon, hydrogen, and oxygen present in the coal and, to a lesser extent, on the sulfur content. Hence, the ratio of carbon to heat content depends on these heat-producing components of coal, and these components vary by coal rank.

Carbon, by far the major component of coal, is the principal source of heat, generating about 14,500 British thermal units (Btu) per pound. The typical carbon content for coal (dry basis) ranges from more than 60 percent for lignite to more than 80 percent for anthracite. Although hydrogen generates about 62,000 Btu per pound, it accounts for only 5 percent or less of coal and not all of this is available for heat because part of the hydrogen combines with oxygen to form water vapor. The higher the oxygen content of coal, the lower its heating value.(3) This inverse relationship occurs because oxygen in the coal is bound to the carbon and has, therefore, already partially oxidized the carbon, decreasing its ability to generate heat. The amount of heat contributed by the combustion of sulfur in coal is relatively small, because the heating value of sulfur is only about 4,000 Btu per pound, and the sulfur content of coal generally averages 1 to 2 percent by weight.(4) Consequently, variations in the ratios of carbon to heat content of coal are due primarily to variations in the hydrogen content.

method developed by the American Society for Testing and Materials. These data observations (samples) covered all of the majo most of the minor coal-producing States (Table FE1). Except for Arizona, North Dakota, and Texas, all of the major coal-producing States were considered to have a sufficiently large number of data observations to yield reliable emission factors.

The ratio of carbon to heat content was computed for each of the 5,426 selected coal samples by coal rank and State of origin un the assumption that all of the carbon in the coal is converted to carbon dioxide during combustion.(7) Variations in the ratios were observed across both coal rank and State of origin. Analysis was performed to determine whether these variations were statistica significant and to ensure that other factors pertaining to the samples (that is, the year the sample was collected and the degree of cleaning the sample received) were not significantly responsible for the observed variations.

Table FE1. Number of Observations by Coal Rank and State of Origin

State of Origin	Anthracite	Bituminous	Sub-bituminous	Lignite
Alabama	--	224	--	--
Alaska	--	--	--	--
Arizona	--	8	--	--
Arkansas	--	8	--	--
California	--	--	--	--
Colorado	--	164	18	--
Georgia	--	1	--	--
Idaho	--	2	--	--
Illinois	--	332	--	--
Indiana	--	51	--	--
Iowa	--	67	1	--
Kansas	--	19	--	--
Kentucky: East	--	486	--	--
Kentucky: West	--	151	--	--
Louisiana	--	--	--	--
Maryland	--	13	--	--
Missouri	--	86	--	--
Montana	--	6	23	2
Nevada	--	4	--	--
New Mexico	--	50	--	--
North Dakota	--	--	--	16
Ohio	--	228	--	--
Oklahoma	--	155	--	--
Oregon	--	--	2	--
Pennsylvania	523	679	--	--
South Dakota	--	--	--	3
Tennessee	--	271	--	--
Texas	--	--	--	11
Utah	--	104	2	--
Virginia	--	169	--	--
Washington	--	181	36	4
West Virginia	--	1,071	--	--
Wyoming	--	133	121	1
Total.	**523**	**4,663**	**203**	**37**

1920-1929	657	12.1
1930-1939	772	14.2
1940-1949	744	13.7
1950-1959	1,043	19.2
1960-1969	557	10.3
1970-1979	339	6.2
1980-1986	418	7.7
Total	5,426	100.0
Degree of Cleaning		
Raw	4,519	83.3
Washed	847	15.6
Partially washed	60	1.1

Note: Total may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, “Analysis of the Relationship Between the Heat and Carbon Cont
U.S. Coals,” September 1992.

Of the total samples, 83 percent were raw coal, with the remainder either washed or partially washed. Cleaning should not materi affect the ratio of a coal's heat-to-carbon content because the process removes primarily non-combustible impurities. This was confirmed by an analysis of variance. There were differences in the carbon-to-heat-content ratios between washed or partially wa and raw coal, but with a R^2 value of 0.06, the differences did little to explain the variation in the ratios. Therefore, no data correcti was warranted to account for the small effect that coal cleaning had on emission factors.

Analysis of variance was used to test the statistical significance of differences in the carbon-to-heat-content ratios across coal ran across State of origin within coal rank. The continuous response variable (the carbon dioxide emission factor) was related to classification variables of rank and State of origin. The carbon dioxide emission factor was assumed to be a linear function of the parameters associated with the coal rank and State of origin.[9]

The statistical analyses (Table FE3) indicated that: (1) there are statistically significant differences in carbon dioxide emission fact across both coal rank and State of origin; (2) coal rank and State of origin each explain approximately 80 percent of the variation carbon dioxide emission factors; and (3) State of origin combined with coal rank is a slightly more powerful explanatory variable th either coal rank or State of origin alone.

Table FE3. Summary of Statistical Analyses Carbon Dioxide Emission Factors by Coal Rank and Sta Origin

Variable	**F Test**	R^2	**MSE**	**Root MSE**
Year Collected	***	0.01	55.18	7.43
Degree of Cleaning	***	0.06	52.07	7.22
Coal Rank	***	0.78	12.24	3.50
State of Origin	***	0.81	10.78	3.28
State of Origin Combined				
with Coal Rank	***	0.82	9.98	3.16

Notes: The F test indicates the statistical significance of differences in the emission factors across levels of the explanatory variable; *** indicates significance at th 0.001 level. R^2 (coefficient of determination) indicates the proportion of total variation in the emission factors explained by the model. MSE (mean square error) is th variance of the emission factors, and root MSE is the corresponding standard deviation.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, “Analysis of the Relationship Between the Heat and Carbon Cont
U.S. Coals,” September 1992.

Carbon Dioxide Emission Factors by Coal Rank and State of Origin

The (arithmetic) average emission factors obtained from the individual samples (assuming complete combustion) (Table FE4)[10] confirm the long-recognized finding that anthracite emits the largest amount of carbon dioxide per million Btu, followed by lignite,

Idaho	--	205.9	--	--
Illinois	--	203.5	--	--
Indiana	--	203.6	--	--
Iowa	--	201.6	[d]207.2	--
Kansas	--	202.8	--	--
Kentucky: East	--	204.8	--	--
Kentucky: West	--	203.2	--	--
Louisiana	--	--	--	[b]213.5
Maryland	--	210.2	--	--
Missouri	--	201.3	--	--
Montana	--	209.6	213.4	220.6
Nevada	--	201.8	--	--
New Mexico	--	205.7	[e]208.8	--
North Dakota	--	--	--	218.8
Ohio	--	202.8	--	--
Oklahoma	--	205.9	--	--
Oregon	--	--	210.4	--
Pennsylvania	227.4	205.7	--	--
South Dakota	--	--	--	217.0
Tennessee	--	204.8	--	--
Texas	--	[f]204.4	--	213.5
Utah	--	204.1	207.1	--
Virginia	--	206.2	--	--
Washington	--	203.6	208.7	211.7
West Virginia	--	207.1	--	--
Wyoming	--	206.5	212.7	215.6
U.S. Average	**227.4**	**205.3**	**211.9**	**216.3**

[a]Based on carbon and heat content data supplied by Usibelli Coal Mining Company for the subbituminous C coal currently being produced in the State.

[b]Based on the CO_2 emission factor for Texas lignite.

[c]Based on the CO_2 emission factor for U.S. lignite.

[d]Derived from “Element Geochemistry of Cherokee Group Coals (Middle Pennsylvanian) from South-Central and Southeastern Iowa,” *Technical Paper No. 5*, Iow Geological Survey (Iowa City, IA, 1984), pp. 15, 48, and 49.

[e]Based on the CO_2 emission factor for subbituminous A coal.

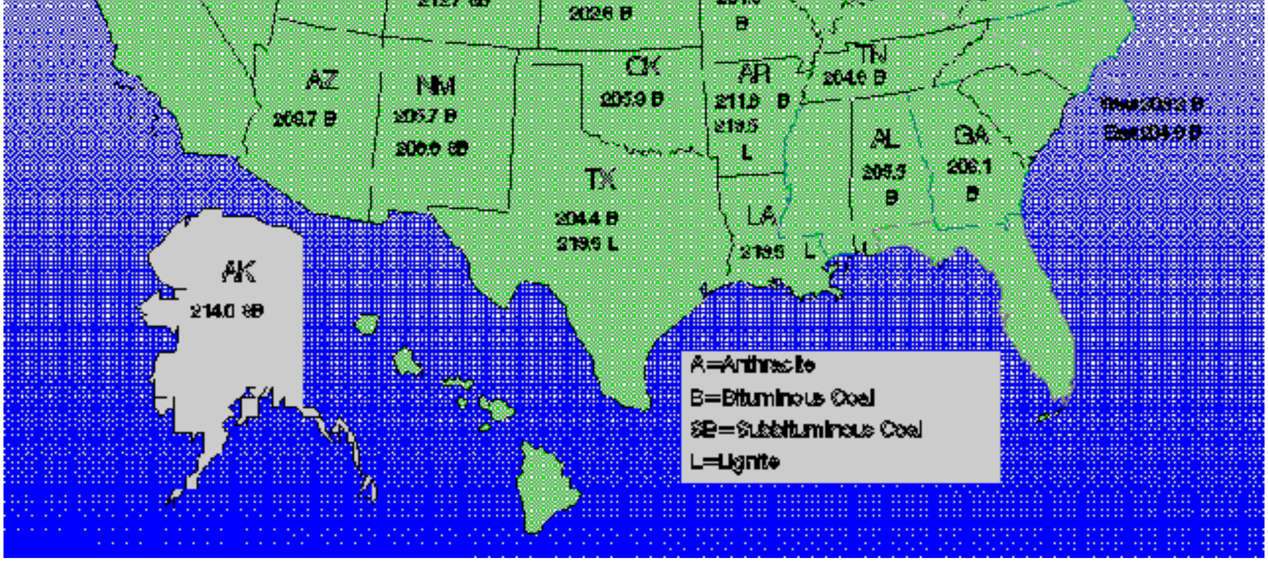
[f]Based on the CO_2 ratio for U.S. high-volatile bituminous coal.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, “Analysis of the Relationship Between the Heat and Carbon Con of U.S. Coals,” September 1992.

In general, the carbon dioxide emission factors are lowest for coal produced in States east of the Mississippi River (Figure FE1), v the predominant coals are bituminous in rank and therefore have relatively low emission factors. By comparison, the coal deposits the West are largely subbituminous coals, which have relatively high emission factors. In a broad sense, the geographic differenc reflect the greater degree of coalification--the process that transformed plant material into coal under the influence of heat and pressure--in the coal-bearing areas in the East.

In the Appalachian Coal Basin, the emission factors for bituminous coal range from a low of 202.8 pounds of carbon dioxide per n Btu in Ohio to a high of 210.2 in Maryland.(12) Pennsylvania anthracite, which is produced in small amounts, has the highest emi factor among all coal ranks (227.4). For Illinois Basin coal, all bituminous in rank, the emission factors are relatively uniform, rang from 203.2 in western Kentucky to 203.6 in Indiana.

Figure FE1: Average Carbon Dioxide Emission Factors for Coal by Rank and State of Origin



West of the Mississippi River, the emission factors for bituminous coal range from more than 201 pounds of carbon dioxide per m Btu in Missouri, Iowa, and Nevada to more than 209 in Arizona, Arkansas, and Montana. About 16 percent of the 1992 coal outpu west of the Mississippi was bituminous coal, with production chiefly from Utah, Arizona, Colorado, and New Mexico.

Subbituminous coal is the predominant rank of coal produced west of the Mississippi River, accounting for 62 percent of the regio total coal output in 1992. Subbituminous coal in Wyoming's Powder River Basin, the principal source of this rank of coal, has an emission factor of 212.7 pounds of carbon dioxide per million Btu. This is the same as for subbituminous coal in Colorado, but slig below that in Montana. The lowest emission factor for subbituminous coal is in Utah (207.1) and the highest is in Alaska (214.0).

The emission factor for lignite from the Gulf Coast Coal Region in Texas, Louisiana, and Arkansas is 213.5 pounds of carbon diox per million Btu. This is 1 to 3 percent lower than the emission factors for lignite in the Fort Union Coal Region in North Dakota, So Dakota, and Montana and for lignite in the Powder River Basin in Wyoming. The 1992 output of lignite accounted for 22 percent o production west of the Mississippi River, with two-thirds from Texas and most of the balance from North Dakota.

All of EIA's carbon dioxide emission factors for coal by rank and State of origin should be considered as "fixed" for the foreseeabl future. This is because detailed coal analysis data are not widely available annually, and because the EIA emission factors, as developed from the EIA Coal Analysis File, are considered to effectively represent the relationship between the carbon and heat content of the various U.S. coals. However, the basic emission factors will be reviewed when sufficient additional coal analysis da are accumulated.

Carbon Dioxide Emission Factors by Coal-Consuming Sector and State

Coal use among the consuming sectors and States varies in quantity as well as in rank and State of origin. Therefore, emission fa by consuming sector in each State were derived by weighting the emission factors by coal rank and State of origin by the respect amounts received by sector.[(13)],[(14)] For comparison, emission factors for 1980 and 1992 are reported in this article (Table FE5). should be noted that the amount of coal received in a certain year may not equal the amount consumed during that year because stock additions or withdrawals. Furthermore, because data on the origin and destination of coal are available only for coal distribu EIA's emission factors for coal consumption by sector assume that the mix of coal received during a certain year was the same as consumed in that year.

The emission factors for coal consumption involving combustion are based on the assumption that all of the carbon in coal is converted to carbon dioxide during combustion. Actually, a very small percentage of the carbon in coal is not oxidized during combustion. The emission factors in Table FE5 can be adjusted to reflect incomplete combustion.[(15)]

In coke plants, coal is carbonized, not combusted, to make coke, which is used in the manufacture of pig iron by the iron and stee industry. Although most of the carbon in the coal carbonized remains in the coke, a small amount is retained in byproducts, some which are consumed as energy sources and others as non-energy raw materials.[(16)] Examination of historical data for coke plan operations indicates that about 10 percent of the carbon in coking coal remains in non- energy byproducts.[(17)] However, no allowances have been made in the emission factors for coke plants (Table FE5) for carbon retained in non-energy byproducts, lea any adjustments to the user's stipulations.

Connecticut	--	204.9	--	--	--	204.7	226.1	220.2	226.1	205.2
Delaware	206.0	206.9	--	--	205.9	207.4	221.8	221.1	206.0	207.0
District of Columbia	--	--	--	--	205.0	--	205.5	206.3	205.4	206.3
Florida	204.0	204.4	--	--	204.2	205.1	205.0	205.7	204.0	204.5
Georgia	204.3	204.8	--	--	204.9	204.9	204.7	204.9	204.3	204.8
Hawaii	--	--	--	--	--	204.4	--	--	--	204.4
Idaho	--	--	--	--	212.6	212.2	205.4	205.0	210.7	211.3
Illinois	207.1	206.2	205.2	206.5	204.2	203.7	203.9	203.9	206.7	205.9
Indiana	204.0	205.6	205.0	206.0	203.7	204.5	203.7	203.8	204.3	205.5
Iowa	207.2	211.1	--	--	205.7	208.3	205.1	204.2	207.0	210.7
Kansas	209.2	210.9	--	--	201.9	205.3	202.2	202.9	209.0	210.8
Kentucky	204.0	204.1	204.6	206.3	205.4	205.4	204.6	204.6	204.1	204.2
Louisiana	212.7	212.9	--	--	203.9	210.9	201.3	--	212.1	212.8
Maine	--	--	--	--	206.0	204.9	216.2	213.0	207.9	205.3
Maryland	206.6	207.0	205.9	--	206.1	208.4	210.6	211.7	206.3	207.1
Massachusetts	206.4	206.8	--	--	206.3	207.0	218.2	214.1	207.6	206.9
Michigan	206.0	208.9	205.5	--	204.8	205.3	205.0	205.0	205.7	208.5
Minnesota	212.9	213.0	--	--	211.6	211.8	208.6	212.3	212.7	212.9
Mississippi	204.7	204.5	--	--	204.0	204.6	202.6	227.4	204.7	204.5
Missouri	204.5	206.2	205.2	--	203.6	204.5	202.1	203.4	204.5	206.1
Montana	213.9	213.5	--	--	211.2	211.4	205.6	213.3	213.7	213.5
Nebraska	211.7	212.7	--	--	212.3	213.1	212.6	219.2	211.7	212.7
Nevada	208.2	208.4	--	--	204.5	204.1	208.4	204.1	208.1	208.3
New Hampshire	206.9	206.3	--	--	207.0	207.1	227.2	225.4	207.0	206.5
New Jersey	206.6	206.6	--	--	218.3	207.3	227.2	227.1	207.1	206.8
New Mexico	205.7	205.7	--	--	212.0	212.7	209.8	206.3	205.7	205.7
New York	205.7	206.1	205.5	206.1	206.9	207.0	218.9	218.0	206.3	206.5
North Carolina	205.6	205.8	--	--	204.8	205.7	204.9	206.2	205.6	205.8
North Dakota	218.8	218.8	--	--	218.8	218.3	218.5	216.8	218.8	218.6
Ohio	204.4	204.4	205.4	206.4	204.0	204.5	203.8	205.5	204.5	204.6
Oklahoma	210.5	212.6	--	--	202.2	207.5	205.7	207.0	210.0	212.3
Oregon	212.7	212.9	--	--	212.7	211.5	205.6	204.1	212.5	212.8
Pennsylvania	206.1	206.2	205.7	206.1	207.9	208.5	221.2	219.7	206.4	206.7
Rhode Island	--	--	--	--	210.0	--	223.9	227.4	217.2	227.4
South Carolina	204.9	205.0	--	--	205.0	205.3	204.8	205.3	204.9	205.0
South Dakota	218.1	218.8	--	--	210.5	212.7	212.0	212.8	217.6	217.9
Tennessee	204.0	204.0	210.2	--	204.8	205.5	204.5	204.6	204.1	204.2
Texas	213.0	212.9	209.8	--	212.3	212.3	213.7	211.0	212.8	212.9
Utah	204.1	204.3	210.8	205.6	205.2	204.1	204.1	204.1	205.7	204.4
Vermont	205.7	--	--	--	207.8	212.2	227.4	227.4	216.0	216.8
Virginia	205.9	206.0	206.2	206.2	205.1	206.2	205.0	206.3	205.7	206.1
Washington	208.7	209.3	--	--	206.3	205.8	204.3	206.9	208.3	209.1
West Virginia	206.9	207.0	205.3	206.7	205.4	206.6	205.0	210.2	206.6	207.0
Wisconsin	207.0	209.9	205.4	--	205.5	206.1	205.8	204.9	206.8	209.5
Wyoming	212.7	212.0	--	--	212.0	212.5	212.3	212.7	212.6	212.1

The change in mix of coal ranks produced reflects the large sectorial and regional shifts in coal consumption that have occurred i past two decades. The electric utility sector dominates coal consumption, and its share has grown substantially. Of total coal consumption in 1992, electric utilities accounted for 87 percent, up from 81 percent in 1980, due mostly to increases in utility coal consumption west of the Mississippi River.[19] The share held by low-rank coals in the electric utility sector increased substantiall Subbituminous coal rose from 24 percent in 1980 to 31 percent in 1992, and lignite grew from 7 to 10 percent during the period. I contrast, bituminous coal fell from 69 percent in 1980 to 58 percent in 1992. The share held by anthracite (about 1 percent) did no change.

Coal used to produce coke is virtually all bituminous in rank; less than 1 percent is anthracite. Only a few States, mostly in Appala supply coking coal. The coke industry, which has been declining, accounted for only 4 percent of total coal consumption in 1992, from 9 percent in 1980.

All ranks of coal are used by the other industrial and the residential/commercial sectors.[21] The other industrial sector accounted percent of total coal consumption in 1992, slightly less than in 1980. However, the emission factor for this sector increased sizabl during the period, due mainly to the rising use of low-rank coals in the West, and contributed to the increase in emission factors fo overall national average. The residential/commercial sector is a relatively minor component of coal consumption, with about 1 per of the total in 1980 and 1992.

As with coal consumption by sector, the amount of carbon dioxide emitted from total coal combustion in a particular State--and he the carbon dioxide emission factor for that State--depends on the mix of coal consumed by various consuming sectors in that Sta during a particular year. When the total energy in Btu from coal consumption by State is known (with no breakdown by coal-consu sector), the State average emission factors can be used to estimate the total amount of carbon dioxide emissions by State.

Publication of Carbon Dioxide Emission Factors

EIA's carbon dioxide emission factors by consuming sector and State will be updated periodically to reflect changes in the mix of coal consumption. EIA plans to report these updates in the *Quarterly Coal Report*, the *State Energy Data Report*, and the annual of *Emissions of Greenhouse Gases in the United States*.

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[1]Coal combustion emits almost twice as much carbon dioxide per unit of energy as does the combustion of natural gas, whereas the amount from crude oil combustion falls between coal and natural gas, according to Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1985-1990*, DOE/EIA-0573 (Washington, DC, September 1993), p. 16.

[2]Examples of previously published emission factors include, in pounds of carbon dioxide per million Btu, single emission factors of 2 in "United States Emissions of Carbon Dioxide to the Earth's Atmosphere," *Energy Systems Policy*, Vol. 14, 1990, p. 323; 210.2 in *Changing by Degrees*, U.S. Congress, Office of Technology Assessment, February 1991, p. 333; 205.6 for bituminous coal in *Green Gases, Abatement and Control*, IEA Coal Research, June 1991, p. 24; and 183.4 in *Limiting Net Greenhouse Gas Emissions in the U States (Executive Summary)*, U.S. Department of Energy, Office of Environmental Analysis, September 1991, p. 37. EIA's first report emission factors by coal rank, published in *Electric Power Annual 1990*, DOE/EIA-0348(90) (Washington, DC, January 1992), p. 124 were as follows: anthracite, 209; bituminous coal, 209; subbituminous coal, 219; and lignite, 213.

[3]U.S. Department of Energy, Pittsburgh Energy Technology Center, "A Coal Combustion Primer," *PETC Review*, Issue 2 (Pittsburgh, September 1990), p. 17.

[4]The relationships of the various heat-producing components of coal are given in Dulong's formula, which provides a method for calculating the heating value of solid fuels. Dulong's formula is as follows: Btu per pound = 14,544C + 62,028(H - O ÷ 8) + 4,050S. C carbon, H is hydrogen, O is oxygen, and S is sulfur, all expressed in percent by weight. The coefficients represent the approximate heating values of the respective components in Btu per pound. The term O ÷ 8 for hydrogen is a correction applied to account for the portion of hydrogen combined with oxygen to form water. For a further discussion of Dulong's formula, see Babcock and Wilcox Co., *Steam/Its Generation and Use*, 40th edition, 1992, p. 9-9.

[5]Potential carbon dioxide emissions can be calculated by use of the following formula: percent carbon ÷ Btu per pound x 36,670 = po (lbs) of carbon dioxide per million (10^6) Btu. Multiply pounds of carbon dioxide per million Btu by 0.123706 to get million metric tons (MMT) of carbon per quadrillion (10^{15}) Btu.

sole producer of coal in Alaska. The others were assigned appropriate average factors for their coal ranks, as noted in Table FE4.

[11]For the coal analyzed in the EIA Coal Analysis File, the average hydrogen content was as follows, by weight (dry basis): anthracite percent; bituminous coal, 5.0 percent; subbituminous coal, 4.8 percent; and lignite, 4.4 percent.

[12]For information on States that produce coal, see Energy Information Administration, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993), and *State Coal Profiles*, DOE/EIA-0576 (Washington, DC, January 1994).

[13]The amount of coal distributed by State of origin and State of destination is reported on Form EIA-6, "Coal Distribution Report," for consuming sectors other than electric utilities, and on Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of and Quality of Fuels for Electric Plants," for utility coal by rank. The amount and energy content of coal consumption by State and se are detailed in Energy Information Administration, *State Energy Data Report*, DOE/EIA-0214, published annually.

[14]Acknowledgement is due Albert D. Gerard, Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels assistance in developing Table FE5.

[15]Adjustments can be made by multiplying the factors by the estimated percentage of carbon converted to carbon dioxide. This has estimated as 99 percent by G. Marland and A. Pippin, "United States Emissions of Carbon Dioxide to the Earth's Atmosphere by Economic Activity," *Energy Systems and Policy*, Vol. 14, (1990), p. 323. EIA's *Emissions of Greenhouse Gases in the United States 1985-1990* (DOE/EIA-0573, September 1993) also assumed 99 percent combustion for carbon emission estimates.

[16]Byproducts include coke oven gas, benzene, creosote, and other hydrocarbons. See, for example, Energy Information Administrat *Coke and Coal Chemicals in 1980*, DOE/EIA-012(80) (Washington, DC, May 1981), for production and disposition of coal chemical materials.

[17]Another source, *Greenhouse Gas Inventory Reference Manual--IPCC Draft Guideline for National Greenhouse Gas Inventories* (IPCC/OECD Joint Programme, 1993), Volume 3, part 2, 1.29, states that on average 5.91 percent of coal going to coke plants ends as light oil and crude tar, with 75 percent of the carbon in these products remaining unoxidized for long periods.

[18]Energy Information Administration, *Coal Production 1980*, DOE/EIA-0118(80) (Washington, DC, May 1982), p. 20; and *Coal Produ 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993), p. 30.

[19]Energy Information Administration, *Quarterly Coal Report July-September 1993*, DOE/EIA-0121(93/3Q) (Washington, DC, Februa 1994), p. 77; and *Quarterly Coal Report October-December 1987*, DOE/EIA-0121 (87/4Q) (Washington, DC, May 1988), p. 46.

[20]Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1992*, DOE/EIA-019(92) (Washington, DC, August 1993), and *Cost and Quality of Fuels for Electric Utility Plants 1980 Annual*, DOE/EIA-0191(80) (Washington, DC, June 1981

[21]Information on the rank of coal distributed to the other industrial and residential/commercial sectors from States producing more th one rank is not available. Therefore, based on available EIA data, the following coal ranks were assigned to distributions of nonutility from the following coal-producing States: Arkansas, bituminous; Colorado, Montana, Washington, and Wyoming, subbituminous; Tex lignite.

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see also:
Historical Coal Data back to 1949
Projected Coal Supply & Demand to 2030
International Coal Data

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Exhibit 8

USFS, *Climate Change Considerations in Project Level NEPA Analysis* (Jan. 13, 2009)

Climate Change Considerations in Project Level NEPA Analysis
January 13, 2009

Introduction

Forest Service Chief Abigail R. Kimbell characterized the Agency's response to the challenges presented by climate change as "one of the most urgent tasks facing the Forest Service" and stressed that "as a science-based organization, we need to be aware of this information and to consider it any time we make a decision regarding resource management, technical assistance, business operations, or any other aspect of our mission."[1] The Forest Service mission is to "sustain the health, diversity, and productivity of the Nation's forest and grasslands to meet the needs of present and future generations." [2]

Ongoing climate change research was summarized in reports by the United Nations Intergovernmental Panel on Climate Change (IPCC) (www.ipcc.ch), US Climate Change Science Program's Science Synthesis and Assessment Products and the US Global Change Research Program. These reports concluded that climate is already changing; that the change will accelerate, and that human greenhouse gas (GHG) emissions, primarily carbon dioxide emissions (CO_2), are the main source of accelerated climate change.

Projected climate change impacts include air temperature increases; sea level rise; changes in the timing, location, and quantity of precipitation; and increased frequency of extreme weather events such as heat waves, droughts, and floods. These changes will vary regionally and affect renewable resources, aquatic and terrestrial ecosystems, and agriculture. While uncertainties will remain regarding the timing and extent magnitude of climate change impacts, the scientific evidence predicts that continued increases in GHG emissions will lead to increased climate change.

This document provides initial Forest Service guidance on how to consider climate change in project-level National Environmental Policy Act (NEPA) analysis and documentation. The following are the basic concepts outlined in this paper:

1. Climate change effects include the effects of agency action on global climate change and the effects of climate change on a proposed project.
2. The Agency may propose projects to increase the adaptive capacity of ecosystems it manages, mitigate climate change effects on those ecosystems, or to sequester carbon.
3. It is not currently feasible to quantify the indirect effects of individual or multiple projects on global climate change and therefore determining significant effects of those projects or project alternatives on global climate change cannot be made at any scale.
4. Some project proposals may present choices based on quantifiable differences in carbon storage and GHG emissions between alternatives.

[1] Abigail R. Kimbell, Chief, USDA Forest Service, February 15, 2008, letter to Forest Service National Leadership Team

[2] USDA Forest Service Strategic Plan, FY 2007 - 2012

This guidance will be revised as more scientific literature is published, climate change management experience is gained, and government policies are established.

Types of Climate Change Effects

Consider two types of climate change effects when appropriate.

- **The effect of a proposed project on climate change** (GHG emissions and carbon cycling). Examples include: short-term GHG emissions and alteration to the carbon cycle caused by hazardous fuels reduction projects, GHG emissions from oil and gas field development, and avoiding large GHG emissions pulses and effects to the carbon cycle by thinning overstocked stands to increase forest resilience and decrease the potential for large scale wildfire.
- **The effect of climate change on a proposed project.** Examples include: effects of expected shifts in rainfall and temperature patterns on the seed stock selection for reforestation after timber harvest and effects of decreased snow fall on a ski area expansion proposal at a marginal geographic location, such as a southern aspect or low elevation.

Climate Change Considerations in Pre-NEPA Analyses, Purpose and Need Statements, and Proposed Actions

Pre-NEPA analyses and identifying a purpose and need are important first steps in developing a proposed action. Typically, land management plan components (especially the desired conditions and objectives) provide a basis for developing the underlying purpose and need for projects.

Future revised plans are likely to recognize climate change influences on local natural resource management and the ecological, social, and economic environments. The comprehensive evaluation report developed for a land management plan revision and its successive updates provide information on conditions and trends, including climate change. These conditions and trends provide the basis and important underpinnings for designing project purpose and need statements, proposals, and alternatives. In the absence of comprehensive evaluation reports, the Resources Planning Act (RPA) assessments[3] include climate change discussions that may provide some relevant information for considering climate change in project analysis.

Pre-NEPA analyses and assessments often consider existing and projected stresses on the environment (e.g., insect and disease epidemics) and should include the potential effects of climate change on our ability to achieve the desired conditions. This analysis may lead to developing purpose and need statements and proposed actions designed to address climate change effects on the local environment.

The effects of climate change on natural resource management are best considered when developing a proposal prior to initiating NEPA. In this way it is efficient to integrate climate change considerations together with the Agency mission objectives. It is possible, and in some projects likely, that proposals may meet the Agency's mission while also enhancing the resilience or adaptive capacity of resources to the potential impacts of climate change. For

[3] Since 1990, the effects of climate change on forest resources have been included as a focus of assessment research. The RPA assessment results are used by public and private land managers to set a broad-scale context for evaluating future changes in renewable resources (see http://www.fs.fed.us/research/rpa/2005rpa/2000-RPA-Assessment-Update.pdf for the April 2007 interim update to the 2000 RPA Assessment).

example, projects designed to restore the health, resilience, and productivity of forested ecosystems may also improve the capability of the stands or landscape to withstand climate change stresses. Also, consider whether climate change may affect the ability to reach a desired condition. For example, the success of the proposal to restore aspen in a particular location may be reduced by expected warmer temperatures and lower rainfall during the next century.

Climate change mitigation[4] could be an objective or a complementary objective for a particular proposal. Also, proposals may include adaptation[5] proposals and adaptive management strategies to allow for uncertainties in environmental conditions resulting from climate change.

Scoping and Climate Change Issues

Scoping is an integral part of environmental analysis and is used, in part, to identify and refine issues, establish analysis criteria, and explore possible alternatives and their probable environmental effects (Forest Service Handbook (FSH) 1909.15, sec. 11).

Scoping is useful to determine if climate change issues are specifically related to the proposed action. Refrain from prematurely dismissing climate change issues as "outside the scope" of the analysis and use the interdisciplinary team and other sources to identify potential cause-effect relationships (if they exist) between the proposal and climate change. Also, refrain from prematurely assuming that NEPA documentation for every proposal must include a climate change discussion.

Determining whether there is a cause-effect relationship is the first step in identifying a potential issue. Consider whether some element of the proposal will result in direct, indirect, or cumulative effects on GHG emissions or the carbon cycle and the direction of effects (e.g., increase, decrease, or combination of both). Consider this example.

> The proposal to underburn 30,000 acres of ponderosa pine stands to maintain a Fire Regime Condition Class 1 (FRCC 1) condition will directly release CO_2 during the burning operation, which contributes to increasing the atmospheric greenhouse gas concentration. However, research indicates that restoration (or maintenance) of a FRCC 1 condition will result in a lower risk of uncharacteristically severe wildfire for those treated acres. This reduced risk has a two-fold effect on GHG emissions or the carbon cycle:
>
> 1) There is a direct beneficial effect on climate change of decreased GHG emissions from these acres because the risk of acres being burned by uncharacteristically severe wildfires would be reduced, and
>
> 2) There is an indirect beneficial effect by treating these acres because live stands of trees will retain higher capacity to sequester carbon dioxide compared to stands killed by uncharacteristically severe wildfires, especially if not immediately reforested.

Some proposals will not have cause-effect relationships to GHG emissions or the carbon cycle, or are at such a minor scale that the direct effects would be meaningless to a reasoned choice

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[4] To paraphrase the IPCC definition (IPCC, 2007) in this context, mitigation is defined as "A human intervention to reduce the sources or enhance the sinks of greenhouse gases."

[5] In this context, adaptation is defined by the IPCC Fourth Assessment Working Group as "Initiatives and measures to reduce the vulnerability of natural and human systems against actual or expected climate change effects."

among alternatives. Examples include: installing a water guzzler for wildlife habitat improvement, approving a use by a commercial outfitter for guided hunting trips, removing hazardous trees in a campground, and chipping brush along a roadside. All NEPA documentation needs to be relevant to informing the decisionmaker and the public about pertinent environmental effects relevant to the decision being made. The scoping process is designed to facilitate relevant analysis, including relevant climate change analysis.

Developing Alternatives Responding to Climate Change Issues

The President's Council on Environmental Quality (CEQ) directs agencies to consider and evaluate reasonable alternatives to proposals (Title 40, Code of Federal Regulation, Part 1502.14 (40 CFR 1502.14)). Alternatives proposed to address climate change issues need to be relevant to the proposed action's purpose and need as well as technically and scientifically feasible. Alternatives may include mitigation measures to reduce GHG emissions, affect carbon cycling, or enhance adaptive capacity. Alternatives developed to respond to climate change issues should clearly relate to the cause-effect relationship between the proposal and climate change and have meaningfully different climate change-related effects when compared to the proposal and other alternatives.

Direct & Indirect Effects Analysis

The CEQ regulations at 40 CFR 1508.7 and 1508.8 and FSH 1909.15, section 15 provide direction and guidance for assessing direct, indirect, and cumulative effects caused by the proposed action and alternatives. In addition to CEQ and agency NEPA requirements, it is important to understand that individual state laws and programs may require reduction, regulation, or monitoring of GHG emissions.

As presented in the discussion on scoping, an analysis of GHG emissions and carbon cycles is not always appropriate for every NEPA document. As with any environmental impact, GHG emissions and carbon cycling should be considered in proportion to the nature and scope of the Federal action in question and its potential to either affect emissions or be affected by climate change impacts. As with any environmental effects analysis, the scope of effects needs to be established in timing and geography relative to the scope of the actions being considered in the alternatives. There will be some situations where quantitative analysis will be useful and others where qualitative analysis will best serve decisionmaking. The following sections provide guidance on considerations for when to use quantitative and qualitative analyses.

Quantitative Effects of Projects on GHG Emissions & Carbon Cycle Climate Change

Many proposed projects and programs will emit greenhouse gases (direct effect) and, thus, contribute to the global concentration of greenhouse gases that affect climate (indirect effect).

Quantifying greenhouse gases emitted and/or sequestered may help choose between alternatives based on relative direct effects trade-offs. Forest Service decisions having the potential to emit or sequester more greenhouse gases; such as, energy facilities, transmission lines, oil & gas development or leases, and some Federal permitting decisions may be best informed by quantitative analyses. Also, quantitative analysis may be best when addressing applicable requirements for reducing, regulating, or monitoring GHG emissions.

Because greenhouse gases mix readily into the global pool of greenhouse gases, it is not currently possible to ascertain the indirect effects of emissions from single or multiple sources (projects). Also, because the large majority of Forest Service projects are extremely small in the global atmospheric CO_2 context, it is not presently possible to conduct quantitative analysis of actual climate change effects based on individual or multiple projects.

Currently the Agency does not have an accepted tool for analyzing all GHG emissions. Models used by the Agency such as *FOFEM 5.5*[6] and *Consume 3.0*[7] can estimate the conversion of fuel loads into emissions (CO_2, Methane, nitrogen oxide (NO_2)), though these tools are for projects which include prescribed burning of vegetation only. These two models are not used to estimate emissions for other project categories such as oil & gas development, transportation, and so on.

Other models that are being or have been developed include carbon life cycle calculators. For example, the Forest Vegetation Simulator (FVS) is a forest growth and yield model that can produce per acre estimates of total stand carbon and removed carbon over time and under various management scenarios and forest disturbances such as fire, insects, and disease. The FVS also tracks how much of the merchantable carbon is stored in products or is emitted with or without energy capture. Efforts are under way to make FVS growth projections sensitive to changes in climate. Guidance and analysis methods will continue to be developed for estimating GHG emissions and carbon sequestration from activities by federal, state and local governments, and non-governmental organizations which the Agency will continue to evaluate for applicability to its environmental analysis.

It is not necessary to calculate GHG emissions for most projects; however, in situations where the responsible official finds the information useful for decisionmaking, such data and conclusions developed through quantitative analysis would normally only be used for comparing alternatives related to direct effects or addressing any applicable regulatory requirements related to GHG emissions. Without enough scientific understanding to draw conclusions about the significance of the quantitative results, qualitative discussions about the potential for greenhouse gases sequestered and emitted are more appropriate for disclosing climate change implications.

Consider the effects of no action frames, the effects tradeoffs of the proposed action and other action alternatives on GHGs emissions. The projected environmental baseline of the no action alternative can be used to compare quantitative impacts of the alternatives with respect to GHG emissions (when applicable); however, because it is not possible to predict the actual effects of a particular project on global climate change, a baseline comparison cannot be made using the no action alternative relative to climate change.

Qualitative Analysis Methods: GHG Emissions & Carbon Cycle

Qualitative effects disclosure for a project's impacts on GHG emissions and carbon sequestration should be couched in the ecosystem's role in the carbon cycle. In this context, descriptions of

[6] *FOFEM 5.5*. is First Order Fire Effects Model, a public domain computer program for predicting tree mortality, fuel consumption, smoke production, and soil heating caused by prescribed fire or http://www.fire.org/index.php?option=content&task=category&sectionid=2&id=12&Itemid=31.

[7] *Consume v. 3.0* is a software application used to predict fuel consumption, pollutant emissions, and heat release based on a number of factors including fuel loadings, fuel moisture, and other environmental factors http://www.fs.fed.us/pnw/fera/research/smoke/consume/index.shtml.

qualitative impacts should disclose the nature and direction (short-term and long-term) of the impact as opposed to the specific magnitude of the impact.

Forests play a major role in the carbon cycle. The carbon stored in live biomass, dead plant material, and soil represents the balance between CO_2 absorbed from the atmosphere and its release through respiration, decomposition, and burning. Over longer time periods, indeed as long as forests exist, they will continue to absorb carbon. Qualitative discussions about these relationships can show the implications of agency decisions about climate change.

The RPA assessment, literature, and national and regional web sites can provide information about general carbon sequestration and GHG implications of various categories of project activities. These resources describe concepts and provide language explaining general connections between management activities and the carbon cycle that can be incorporated by reference in qualitative discussions.

Cumulative Effects Analysis

As GHG emissions are integrated across the global atmosphere, it is not possible to determine the cumulative impact on global climate from emissions associated with any number of particular projects. Nor is it expected that such disclosure would provide a practical or meaningful effects analysis for project decisions.

Where a proposed project would be anticipated to emit relatively large amounts of greenhouse gases (e.g., large-scale oil and gas development project), the following may be appropriate.

1. Quantify the expected annual and total emissions from the project, where possible, using already generated data from air quality analyses;
2. Provide context for these numbers by comparing to other emission sources (e.g., individual, regional, national, global); and
3. Qualitatively describe the effects of GHG emissions on climate change.

A qualitative cumulative effects discussion could incorporate a summary of local, regional, or national climate change scientific assessments to recognize overall climate change effects expected as a result of all contributions to climate change. However, it will not be possible and it is not expected that the effects of a particular project or multiple projects can be specifically attributed to those effects. The land management plan comprehensive evaluation and RPA Assessment may include information that would help in this summary.

Uncertainty Regarding Climate Change

Although it is possible to quantify a project's direct effects on carbon sequestration and GHG emissions, there is no certainty about the actual intensity of individual project indirect effects on global climate change. Uncertainty in climate change effects is expected because it is not possible to meaningfully link individual project actions to quantitative effects on climatic patterns.

Complete quantifiable information about project effects on global climate change is not currently possible and is not essential to a reasoned choice among alternatives. However, based on climate change science, we can recognize the relative potential of some types of proposals and alternatives to affect or influence climate change and therefore provide qualitative analysis to help inform project decisions. .

Findings of No Significant Impact Related to Climate Change

Context considerations together with 10 intensity factors are used to determine whether a proposed action's environmental impact may be significant (40 CFR 1508.27). A Finding of No Significant Impact documents a Federal agency's reasons why a proposed action will not have a significant effect on the quality of the human environment and an environmental impact statement (EIS) will not be prepared (40 CFR 1508.13).

The responsible official determines the "significance" of effects of a proposal, given the context and intensity of the effects. Significance varies with the context or setting of the proposed action. For a site-specific action, significance usually depends on the effects in the locale rather than the world as a whole. Therefore, actions potentially having effects on climate change that are not discernible at the global scale are unlikely to be determined significant from a climate change standpoint for that reason. The determination is relative to the scope of the environmental effects described in an environmental assessment. Because the context of individual projects and their effects cannot be meaningfully evaluated globally to inform individual project decisions, it is not possible and it is not expected that climate change effects can be found to be "significant" under NEPA and therefore require EIS preparation.

Of the 10 "intensity" factors in the CEQ definition of significance, 5 may be questioned or raised as reasons for requiring an EIS. Factors 2, 4, 5, and 7 can be addressed by explaining the context of the actions and the scope of the effects:

Factor 2 – The degree to which the proposed action affects public health or safety.

Factor 4 – The degree to which the effects on the quality of the human environment are likely to be highly controversial.

Factor 5 – The degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks

Factor 7 – Whether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts.

We can recognize that global climate change may affect human health, that there is uncertainty and unknown risks associated with global climate change, and that the ultimate effects on climate change are indeed the results of incremental cumulative effects of many actions, most of which are outside the Agency's control. However, we should also recognize in our findings that we cannot discern significant climate change effects of our proposals, given the context of projects and plans and the lack of effects that can be meaningfully evaluated under current science, modeling, and policies.

Factor 10 – Whether the action violatesthreatens a violation of Federal, state, or local law or requirements imposed for the protection of the environment.

Under this factor, it would be difficult to determine the significance of effects of one project on greenhouse gases directly, and therefore climate change indirectly, as there are currently no Federal statutes, regulatory standards, or policy direction on the significance of such effects. Until meaningful, accepted thresholds are adopted against which to weigh any project-related GHG emissions, it will not be possible to determine whether a specific project will have a significant effect under this factor.

If a state does have a threshold in law or regulation for GHG emissions, then the environmental analysis needs to address the project's relationship to that threshold (40 CFR 1508.27 (b)(10)). As states and counties begin to develop such thresholds, NEPA practitioners must be aware of their current local situation and how factor 10 should be addressed in a finding of no significant impact.

Decision Documents

It may be appropriate for the decision document rationale to include some indication of how climate change considerations (if any) were weighed during decisionmaking. These statements should reference relevant NEPA documents, assessments, and science to substantiate findings.

In recognizing agency responsibility to consider climate change, the responsible official can cite the Forest Service mission to "sustain the health, diversity, and productivity of the Nation's forests and grasslands to meet the needs of present and future generations" and state how their decision considered climate change issues. They can explain how climate change was considered to the extent possible given the scope of the project, the scope of the effects, and how all the effects were weighed along with the benefits in arriving at a decision. This would convey Chief Kimball's intent that we need to be aware of climate change information and to consider it when making decisions.

Responding to Comments Regarding Climate Change

The CEQ regulations (40 CFR 1503.4) provide direction that is applicable when responding to comments about climate change.

1. Modify alternatives including the proposed action.
2. Develop and evaluate alternatives not previously given serious consideration by the Agency.
3. Supplement, improve, or modify the analysis.
4. Make factual corrections.
5. Explain why the comments do not warrant further agency response, citing the sources, authorities, or reasons which support the Agency's position and, if appropriate, indicate those circumstances that would trigger agency reappraisal or further response.

Though some examples may help, no standard list of responses to comments can work across all national forests or grasslands. However, given the context of global climate change, there are some elements of individual responses that can be standardized. The following are potential information sources to use in response to comments:

- EPA State of Knowledge on Climate Change Science.
- Regional appeal websites contain responses to appeal issues, including those related to climate change http://www.fs.fed.us/appeals/.
- Agency climate change science syntheses and assessments to support forest plan revisions and projects expected to be completed by January 1, 2009.

Tools, Resources, Literature, and Websites

- Examples - Purpose and need, proposed action, issue statement, alternative development, effects analysis, and response to comments examples are available on the intranet at www.examples.fs.fed.us
- Inter-governmental Panel on Climate Change
- US Climate Change Science Program
- Climate Impacts Group, University of Washington
- Climate Change Resource Center
- Climate Assessment for the Southwest, University of Arizona
- Southern Global Climate Change Program
- EPA Greenhouse Gas Equivalencies Calculator
- EPA Climate Change & Forests
- Regional Integrated Sciences and Assessments Program, National Oceanic and Atmospheric Administration
- United States Climate Action Partnership
- Forest Plan Implementation (1900-1) Training Materials
- Consortium for Research on Renewable Industrial Materials
- Forest Vegetation Simulator (FVS)
- CONSUME
- Tools for Carbon Inventory, Management, and Reporting
- Climate, Fire, and Carbon Cycle Sciences

References & Literature

- Science and Assessment Program (SAP 4.3), The Effects of Climate Change on Agriculture, Land Resources, Water Resources, and Biodiversity in the United States
- Science and Assessment Program (SAP 4.4), Adaptation Options for Climate-Sensitive Ecosystems and Resources, U.S. Climate Change Science Program.
- Silviculture and Forest Management Under a Rapidly Changing Climate, Millar, et al, Ecol. Applications, 2007.
- British Columbia Department of Forests Research Publications by Dave Spittlehouse for the Pacific Northwest.
- Intergovernmental Panel on Climate Change's Fourth Assessment Report.
- Climate change and Forests of the Future: Managing in the Face of Uncertainty, *Ecological Applications*, 17(8), 2007, pp. 2145–2151.
- April 2007 interim update to the 2000 RPA Assessment.

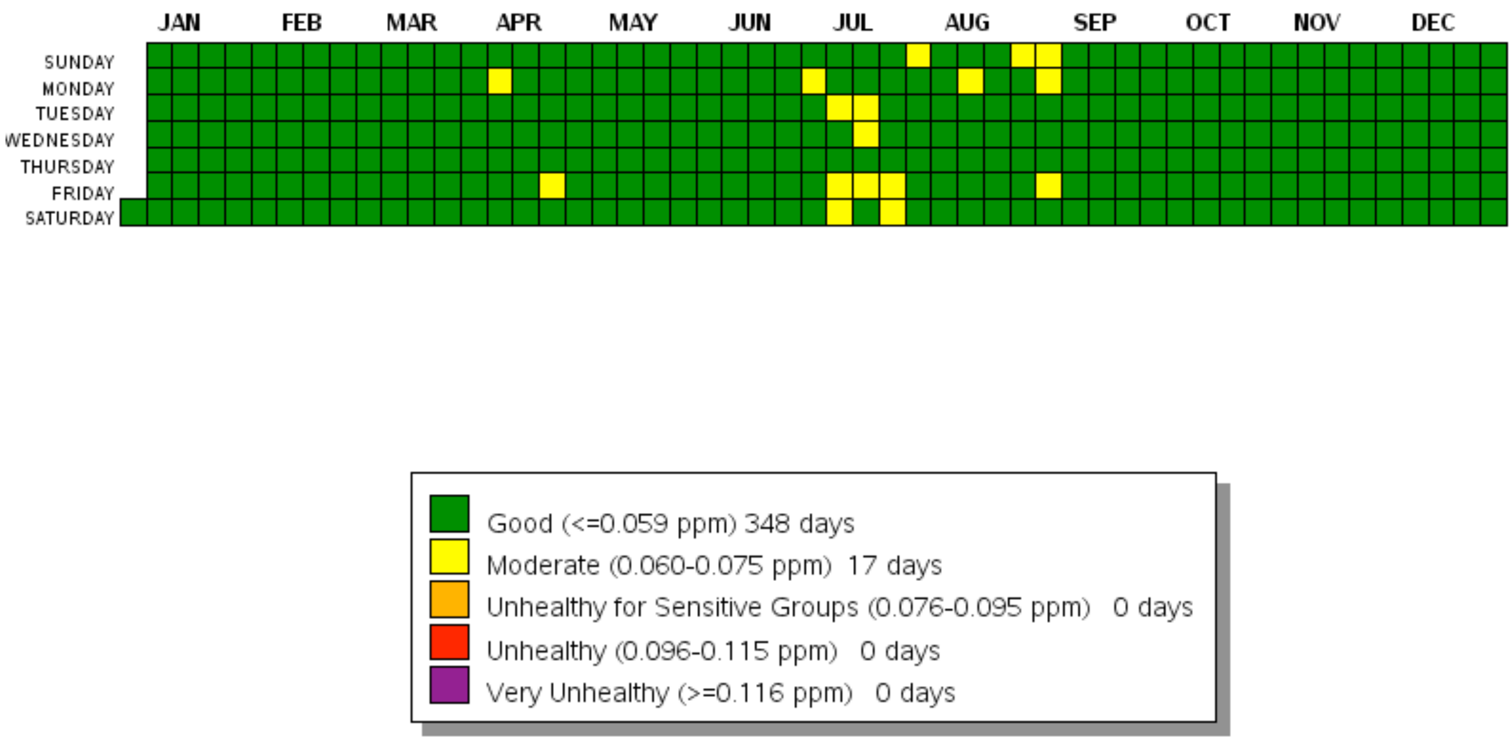
Links for Forest Service Employees

- Region 1 and Region 9 Forest Service internal websites include sample comments.
- The Project, Appeals and Litigation System (PALS) Forest Service internal website is designed to track appeal issues, including those for climate change.

Exhibit 9

U.S. EPA, *Daily Ozone AQI* Levels, 2005-2010, Campbell County, Wyoming

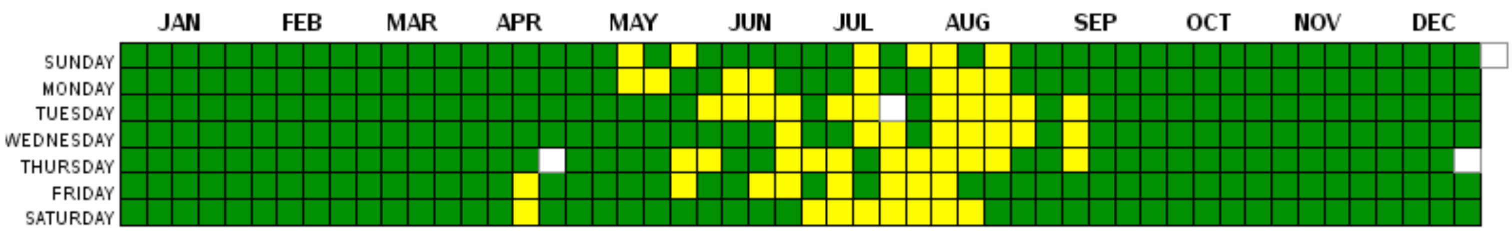
Daily Ozone AQI Levels in 2005
Campbell County, WY

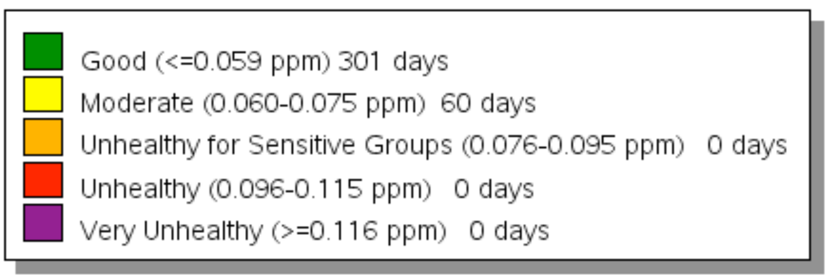


Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 08FEB11

This request took 3.94 seconds of real time (v9.2 build 1495).

Daily Ozone AQI Levels in 2006
Campbell County, WY

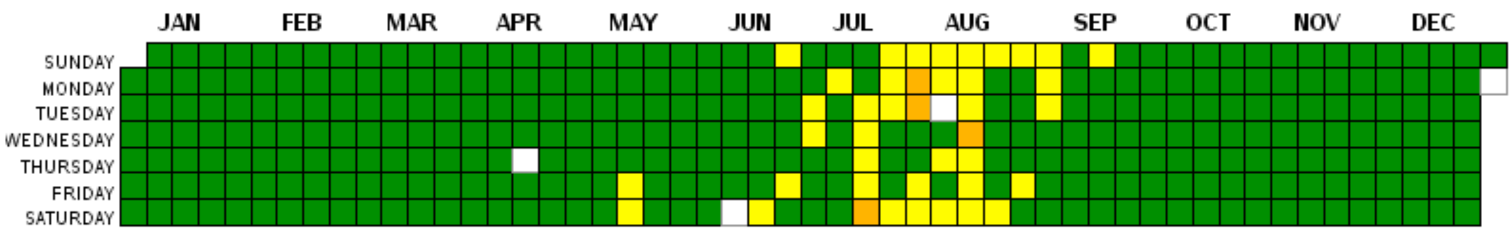




Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 08FEB11

This request took 3.67 seconds of real time (v9.2 build 1495).

Daily Ozone AQI Levels in 2007
Campbell County, WY

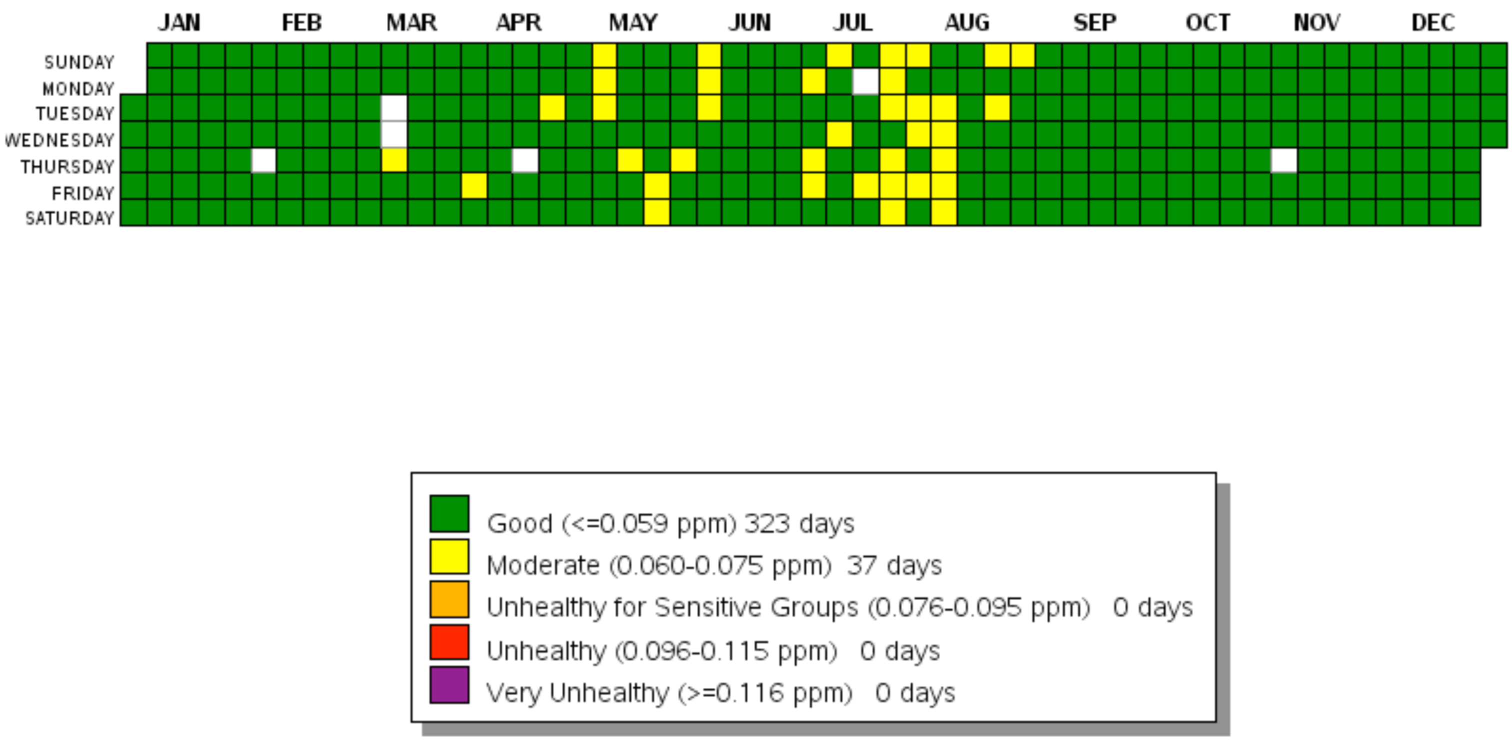


- Good (<=0.059 ppm) 320 days
- Moderate (0.060-0.075 ppm) 37 days
- Unhealthy for Sensitive Groups (0.076-0.095 ppm) 4 days
- Unhealthy (0.096-0.115 ppm) 0 days
- Very Unhealthy (>=0.116 ppm) 0 days

Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 08FEB11

This request took 4.14 seconds of real time (v9.2 build 1495).

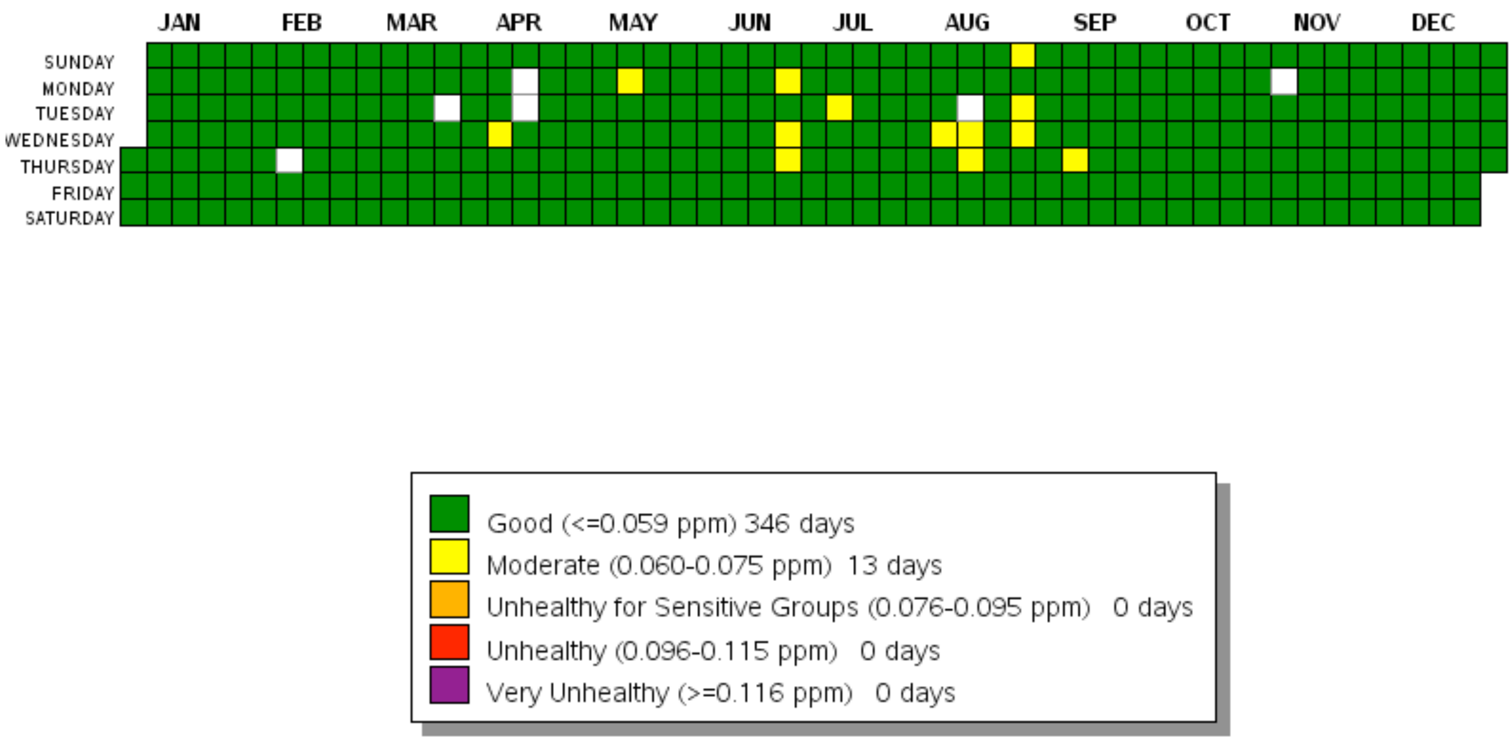
Daily Ozone AQI Levels in 2008
Campbell County, WY



Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 08FEB11

This request took 4.19 seconds of real time (v9.2 build 1495).

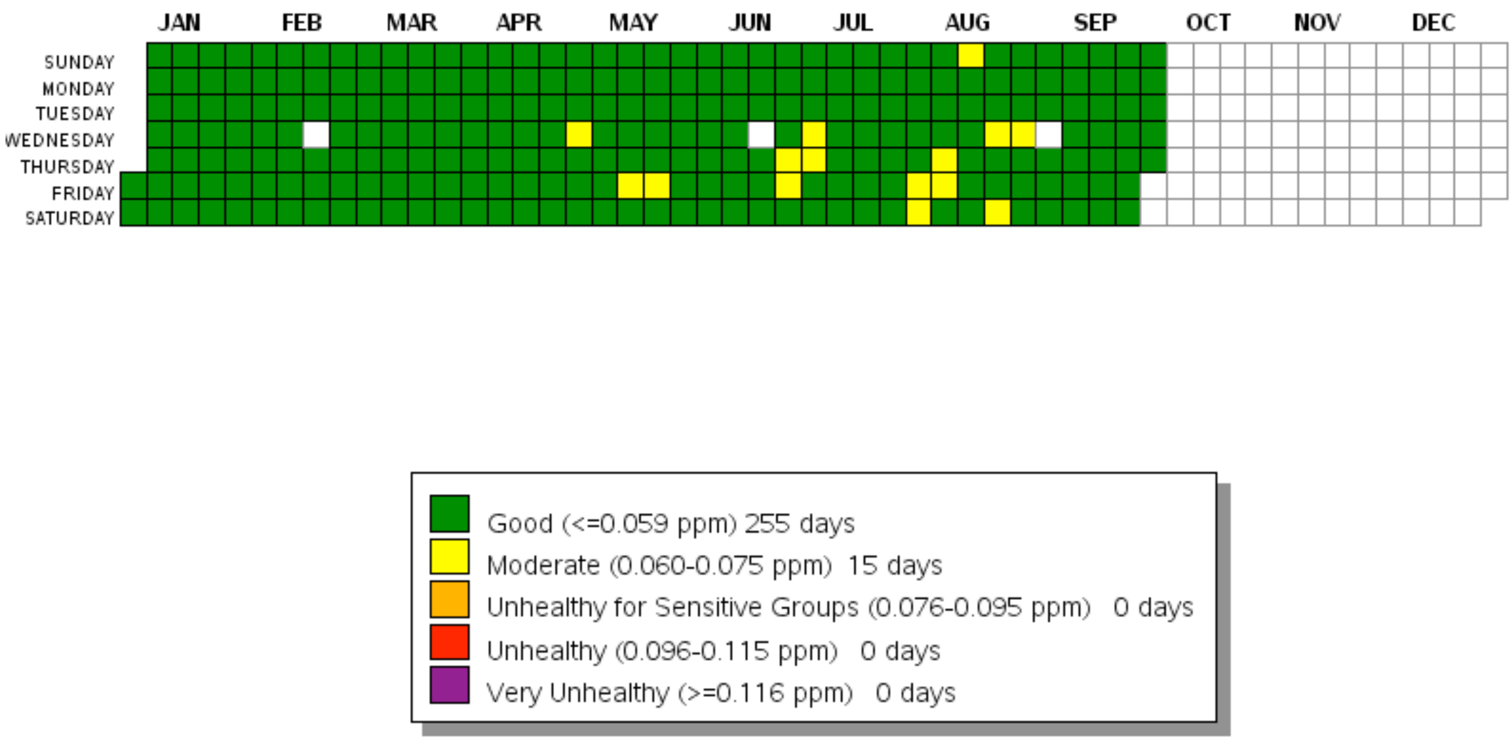
Daily Ozone AQI Levels in 2009
Campbell County, WY



Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 08FEB11

This request took 7.26 seconds of real time (v9.2 build 1495).

Daily Ozone AQI Levels in 2010
Campbell County, WY



Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 08FEB11

This request took 3.93 seconds of real time (v9.2 build 1495).

Exhibit 10

U.S. EPA, Comments on Wright Area Coal DEIS (Sept. 10, 2009)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: EPR-N SEP 10 2009

Sarah Bucklin
Project Manager
Bureau of Land Management
Wyoming High Plains District Office
2987 Prospector Drive
Casper, WY 82604

Re: Draft EIS for Wright Area Coal Lease Applications
[CEQ# 20090209]

Dear Ms. Bucklin:

The U.S. Environmental Protection Agency (EPA) has reviewed the Bureau of Land Management's (BLM) Draft Environmental Impact Statement (EIS) for Wright Area Coal Lease Applications to assess the consequences of holding competitive sales for modified maintenance lease tracts on 18,000 acres of federally-owned solid minerals making available 2.570 billion tons of surface-minable coal in the Powder River Basin (PRB) of Wyoming. Our review and comments are provided pursuant to Section 102(2)(C) of the National Environmental Policy Act (NEPA), 42 U.S.C. Section 4332(2)(c) and Section 309 of the Clean Air Act, 42 U.S.C. Section 7609.

Air quality continues to be EPA's main concern for the energy activities in the PRB. Large surface coal mines have the potential to become particulate emission sources in the PRB contributing to air quality degradation. Although the Wyoming Department of Environmental Quality (WDEQ) has by statute, the authority and responsibility to require mitigation for air quality impacts, the Final EIS should propose additional mitigation measures for air quality impacts that are not directly related to the new leases such as additional dust suppression. During many recent years, air quality monitoring in the area has shown exceedances of the PM_{10} standards (particulate matter less than 10 micrometers in diameter, commonly referred to as fugitive dust). Air quality modeling results from the PRB Coal Review (cumulative air quality effects) also predict additional increases in PM_{10} emissions for this mining area, potentially causing exceedances of the air quality standard. Therefore, we are recommending that the Final EIS analyze more effective dust control measures than the current Best Available Control Technology (BACT) and Best Available Control Measure (BACM) practices and require additional mitigation to reduce fugitive dust from mining the lease tracts and the cumulative effects of mining in the surrounding area.

EPA also has concerns about the impacts of nitrogen dioxide emissions from cast blasting shots and whether the proposed mitigation is sufficient. Voluntary blasting restrictions to control public exposure to NO_x emissions have not always been implemented. Depending on the proximity of public exposure to the explosive fumes, it may be appropriate to incorporate the mitigation measures into the terms of the leases. The most successful control measure would be to eliminate cast blasting entirely as the Eagle Butte Mine has done; alternatively, smaller shots using reduced amounts of explosives could become the standard practice.

The existing PRB Coal Review studies were used effectively in the Draft EIS discussion of the cumulative environmental consequences. We understand that an update to the PRB Coal Review air quality analysis is currently under consideration by BLM. This update is a proactive action by BLM that we support and we are always willing to provide assistance or participate in air quality working groups, if needed. Such an analysis might inform an appropriate control measure strategy to be developed to avoid any adverse impacts.

Consistent with section 309 of the Clean Air Act, it is EPA's responsibility to provide an independent review and evaluation of the potential environmental impacts of this project. In accordance with our policies and procedures for reviews under NEPA and Section 309 of the Clean Air Act, EPA is rating this Revised Draft EIS as EC-2 (EC - Environmental Concerns, 2 - Insufficient Information). This rating means that our review identified environmental impacts that should be avoided in order to fully protect the environment and the Draft EIS lacked sufficient information and analysis regarding impact mitigation and the analysis of the proposed action's impact on climate change. In addition to EPA's detailed comments on the Draft EIS, a full description of EPA's EIS rating system is enclosed.

Please see the following detailed comments for our specific environmental and informational concerns. If you have any questions regarding our comments or this rating, please contact me at (303) 312-6004, or you may contact James Hanley of my staff at (303) 312-6725.

Sincerely,

/s/ Robin Coursen (acting for)

Larry Svoboda
Director, NEPA Program

Enclosure

Wright Area Coal Lease Applications DEIS
Technical Comments

Air Quality Modeling

1. Near Field Impacts -- Direct project impacts using the air dispersion model ISCLT3 for annual PM_{10} and annual NO_x concentrations were disclosed in the Draft EIS for base case and maximum emission scenario years for each of the three mines. No $PM_{2.5}$ impact analysis was conducted in the near field for the Draft EIS. In all cases the modeling predicted compliance with the PM_{10} annual Wyoming Ambient Air Quality Standards (WAAQS). No 24-hour PM_{10} near field predictions were made for the Draft EIS in conformance with the 1994 Memorandum of Agreement between EPA and Wyoming Department of Environmental Quality (WDEQ) that involves comprehensive air monitoring conducted in the area in lieu of PM_{10} modeling. NO_x modeling results were compared against the NO_2 National Ambient Air Quality Standards (NAAQS) (assuming 100% NO_x to NO_2 conversion) and were generally lower than the NAAQS with one exception. For the Jacobs Ranch Mine year 2013, the NO_x prediction was 55 ug/m^3 which exceeds the NO_2 NAAQS by 2 ppb.

Recommendation: The Final EIS should present potential $PM_{2.5}$ near field impacts from the project and identify measures to reduce the NO_2 impacts from the Jacobs Ranch Mine.

2. Additional PM_{10} Mitigation -- Monitoring data in 2007 exceeded predictions of the WDEQ Permit Model. WDEQ approaches PM_{10} control in the Wyoming PRB coal mines through use of a conservative Fugitive Dust Model to determine coal production levels that will not exceed the annual NAAQS at any monitor when required BACM (Best Available Control Methods) are used; and with monitoring data (in the absence of accurate short term models) to show that at actual production levels, 24-hour PM_{10} NAAQS exceedances do not occur.

Recommendation: To ensure compliance with the PM_{10} standards, EPA believes that either mine emissions or emissions from other area sources must be reduced before PRB operations are expanded to realize the upper range of future coal production. We recommend that the Final EIS add additional mitigation measures to reduce fugitive dust emissions. These mitigation measures would be in addition to BACM and should be incorporated into the terms of the proposed leases. Through our discussions with BLM on air quality, it appears that it may be more efficient for the lessees to be obligated for mitigation for other activities on BLM land or private lands.

3. NO_x, NO_2 & Ozone - Many of the voluntary blasting (cast blasts) restriction measures implemented by the mines appear to be successful in reducing or eliminating public exposure to high NO_2 emissions. However, NO_2 emission rates described in Section 3.4.3.2.1, page 3-70 of over 4,500 tpy for the Black Thunder Mine alone are very high and may contribute to visibility impairment and the formation of ozone. EPA is

concerned with measured ozone concentrations in the surrounding area. For example, the WDEQ's Thunder Basin National Grassland site has a design value of 72 ppb (2006-2008), which is very near the NAAQS of 75 ppb. Also, on June 26, 2009, EPA published a proposed revision to the NO_2 NAAQS. EPA is considering a new NO_2 NAAQS over a 1-hour averaging period of between 80 and 110 ppb. The EPA plans on finalizing the rulemaking on January 22, 2010. Given the short-term nature of the cast blasts coupled with a very high emission rate of over 4,500 tpy, we are concerned that compliance with the proposed NO_2 1-hour NAAQS may be problematic.

Recommendation: Because of the high levels of existing ozone levels and our concerns with short-term NO_2 impacts, we recommend that the BLM and proponents should consider additional NO_x mitigation strategies that would reduce visibility impairment, ozone and NO_2 concentrations in the area.

4. (Draft EIS section 3.4.3.2.1) Mitigation for Nitrogen Dioxide Emissions. On page 3-66, the Draft EIS states that Wright Area Mines have already implemented voluntary measures to reduce NO_2 emissions. Because the measures are voluntary, the mine operators may choose not to implement the mitigation measures. It should also be noted that the measures for the mines do not include a prohibition of blasting when conditions are unfavorable (large blast, wet conditions, weather inversions, little wind, wind direction towards residences/road, etc.) The existing mitigation merely requires notification and monitoring.

Recommendation: We recommend that a condition of approval be added to the lease prohibiting blasting when conditions are unfavorable. The mines would then need to analyze the size of blasts in conjunction with weather conditions and potential public exposure to prevent exceedances of the EPA and NIOSH recommended toxicity levels. The Final EIS also needs to more fully describe the types and levels of mitigation and how the mitigation will be implemented to reduce exposure to nitrogen dioxide. For example we understand that several of the mines have reduced the sizes of blasts, changed the composition of the explosive agents used for blasting, and/or changed the placements of blasting agents.

Specific Air Quality Narrative Comments

5. The Executive Summary (ES) presents significance levels for fugitive dust and tailpipe particulates and includes a short discussion of other existing air pollutant sources. EPA recommends inclusion of a summary of the greenhouse gas emissions analyzed in Section 3 and 4 within the Executive Summary.

6. ES-36. It would be helpful to present the value for the annual NO_2 NAAQS within the text so that readers may make comparisons to the maximum modeled NO_x concentrations shown on Figures ES-8, ES-9, and ES-10.

7. Figure ES-11. Explain in the text why a 3-mile buffer was chosen to depict the potential for public exposure to emissions from surface mining operations.

8. Tables 4-11 through 4-14 of the Draft EIS disclose potential cumulative impacts that were tiered from the October 2008 PRB Coal Review Cumulative Air Quality Effects project. The PRB Coal Review disclosed cumulative adverse impacts from $PM_{2.5}$, PM_{10}, and visibility impairment at Class I areas under the three modeled scenarios. Specifically, for both the lower and upper coal development scenarios in 2015, the 24-hour $PM_{2.5}$ prediction is 179.5 µg/m^3 (NAAQS is 35 µg/m^3) and the annual $PM_{2.5}$ prediction is 18.7 µg/m^3 (NAAQS is 15 µg/m^3). For both the lower and upper coal development scenarios, the PM_{10} modeling predicted 24-hour impacts of 512.8 µg/m^3 (NAAQS is 150 µg/m^3). These predictions are all well over the NAAQS for $PM_{2.5}$ and PM_{10}. The 1994 Memorandum of Agreement between EPA and WDEQ does incorporate monitoring in lieu of short-term PM_{10} modeling. However, for planning purposes we believe the type and location(s) of the emissions contributing to these concentrations should be presented in the Final EIS. Since the PRB Coal Review modeling work is under consideration by BLM, we believe this updated analysis should capture all sources within a modeling domain large enough to determine cumulative impacts including PM_{10}, ozone and visibility. The analysis should also present source attribution contributions associated with the locations of predicted elevated pollutant levels. Such an analysis might inform an appropriate control measure strategy to be developed to avoid the predicted adverse impacts.

9. 3.4.1.1 (Table 3-8) Assumed Background Air Pollutant Concentrations. This table contains references to several air monitoring site data collected generally from 2002-2004. The Table units are presented as ug/m^3, however, for some of the parameters it appears that ppb units may be shown instead. We recommend using consistent units throughout the table. It also appears that some of the units are incorrect. Please ensure units are correct. In addition, there are much more recent data available from 2006 and 2007 that should also be incorporated into the table.

    a. The background concentration for NO_2 is listed for the Thunder Basin National Grassland Monitoring Site, which is located more than 20 miles north of Gillette. Please replace this location with the WDEQ site southwest of Gillette which generates NO_2 monitoring data and would be more representative of true background conditions.

    b. Data for SO_2 should be updated to include more recently measured concentrations at the Wyodak Site 4 monitoring station in Campbell County, Wyoming.

    c. It is unclear why data from Eagle Butte Mine was used for background PM_{10} in Table 3-8. There are numerous nearby PM_{10} monitoring sites in the southern PRB, including the WDEQ site southwest of Gillette. For air quality analysis purposes, data presented as Background Data should be data that represents base case ambient conditions near the proposed action.

    d. Page 4-42 references the Memorandum of Agreement between the WDEQ and EPA (January 24, 1994). A condition of the agreement is to continue PM_{10}

monitoring near the mine to ensure compliance with the 24-hour PM_{10} NAAQS. BLM should ensure that the mine operator(s) consult with the WDEQ on any monitoring site adjustments or additions due to the proposed expansion of the active mine area. Particular attention should be made to placement of monitors closer to the active mine areas in order to determine maximum impacts from the mines.

10. Section 3.4.2.3, Page 3-63, text states that "While PRB mining operators have already implemented these control measure in practice, formal approval of the NEAP [Natural Event Action Plan] for the mines in the PRB by EPA Region VIII is still pending". EPA Region VIII approved the WDEQ NEAP on March 13, 2007.

11. Section 3.4.2.3, Page 3-63, the full paragraph describes the NEAP for the mines in the PRB in the context of an Exceptional Event; this is no longer strictly applicable. The Exceptional Event Rule of March 22, 2007 no longer requires a NEAP. However, according to the preamble to the Exceptional Event Rule (Signed March 22, 2007, Effective May 21, 2007), "The EPA believes that it is advantageous for States to keep NEAPs in place that are currently being implemented in order to address the public health impacts associated with recurring natural events such as high wind events. However, following the promulgation of this rule, States will no longer be required to keep NEAPs in place that were not approved as a part of a SIP for an area". We believe the NEAP should be retained because it provides the flexibility to control other emission sources, like fugitive emission sources, that otherwise might not be controlled with BACT. We believe the BACM specified in the NEAP contains an appropriate and reasonable minimum level of control as required under the Exceptional Event Rule for the PRB coal mines. Additional mitigation of PM_{10} should be introduced if PM_{10} exceedances occur at Wright Area Coal Lease mines.

12. We recommend that the Final EIS disclose that emissions from coal combustion have been identified as a significant source of atmospheric mercury. EPA's web site at http://www.epa.gov/mercury/report.htm has several reports summarizing the environmental impacts of mercury, primarily bioaccumulation in the aquatic food web. Concentrations of mercury emitted as a result of combustion vary depending on the chemistry of coal deposits and the type of air pollution controls.

Recommendation: For purposes of the Final EIS, we recommend including any existing information on mercury emissions from power plants currently burning coal from the PRB mines.

Cumulative Environmental Consequences

13. Adverse visibility impairment impact days were also identified in the Draft EIS. These include 26 days at Badlands National Park, 32 days at the Northern Cheyenne Indian Reservation and 18 days at the Wind Cave National Park for the lower 2015 Coal Development scenario.

Recommendation: The Final EIS should add additional mitigation measures to reduce the days of visibility impairment in these Class 1 areas. Since the PRB Coal Review modeling work is under consideration by BLM, we believe this updated analysis should capture all sources within a modeling domain large enough to determine cumulative impacts including PM_{10}, ozone and visibility. The analysis should also present source attribution contributions associated with locations of predicted elevated pollutant levels. Such an analysis might inform an appropriate control measure strategy to be developed to avoid the predicted adverse impacts.

14. Section 4.2.14.1 presents an analysis regarding global climate change and Greenhouse Gas (GHG) emissions. EPA recommends the following updates and changes to this section:

    a. Greenhouse gas emissions from burning the coal should be calculated in the Final EIS and reported in millions of metric tons CO_2-equivalent per year or comparable units. Although the coal is sold as a commodity, the emissions can be calculated using coal production and emissions factors. For a more detailed analysis, the BLM may want to consider calculating the differences in CO_2 emissions from the combustion technologies described in the Draft EIS (standard combustion, IGCC, advanced pulverized coal, circulating fluidized bed).

    b. The Final EIS should disclose the measures the coal mines are using or plan to use to reduce or mitigate direct greenhouse gas emissions, including but not limited to reduction of coalbed methane and railroad locomotives' emission reductions. Mitigation measures designed to reduce the GHG emissions per unit of coal produced needs to be analyzed.

    c. The Final EIS should update the information regarding climate change modeling. For example, the last two paragraphs on page 4-110 of the Draft EIS, starting with "Tools necessary to quantify incremental climatic changes associated with those factors for the projected development activities in the PRB are presently unavailable" and the last paragraph on page 4-110 should be deleted or rewritten to describe current climate change prediction modeling.

    d. The last paragraph of Section 4.2.14 suggests that estimates of greenhouse gas emissions from the combined or cumulative mine operations can be found at Section 3.4.5, but the reference should be to Table 3-24 found in Section 3.18.2 on Page 3-307.

The broader cumulative impact analysis should also factor in the success of reclamation and mitigation plans for various resources. Mining reclamation works well for restoring some aspects of resources such as grazing livestock and wildlife, and visual aesthetics. Other resource values may take a longer time to return to full function or may not be restorable at all (e.g., wetlands, groundwater, and unique habitats).

Recommendation: We recommend that the impact sections for resources that are substantially impacted by cumulative impacts be reevaluated to determine how the impacts will overlap in time and for the resource as a whole. For example, does the timing of maximum impact from other activities (e.g., coalbed methane) coincide with the peak of impacts from coal mining? Are any resources impacted by coal mining approaching sustainability limits because of cumulative impact levels?

Wetlands

15. (Section 3.7.3) Wetlands Compliance, Mitigation and Monitoring. The wetlands mitigation plan needs to be amended to compensate for the long-term loss of wetland values during and following mining. The mitigation ratios may need to be increased to compensate for the temporal loss of wetlands. Wetlands obviously cease to function during the 10 to 20 years of mining. However, wetlands fed by groundwater will not regain function until the ground water table recovers. We recommend that additional mitigation be established to compensate for the long-term loss of wetland values. The mitigation plans for previous or current reclamation may provide good locations for increasing wetlands in the area. Alternatively, the mines may want to improve other wetlands damaged by overgrazing, poorly constructed roads, or off-road vehicle damage.

Wildlife

16. (Section 4.2.8.4) Special Status Species. The analysis for wildlife impacts should be based on the habitat needs of the species of concern, rather than the specific boundaries of the mines and lease tracts. There also needs to be sufficient analysis to understand the impacts of the Lease by Application (LBA) decisions. For example, on page 4-71, the Draft EIS states that no sage grouse leks occur within five miles of the Wright Area Coal LBA tract. It is unclear if the absence of nesting areas is important to the decline in sage grouse population or if there are sufficient numbers of leks nearby to sustain the population. In addition, this information does not appear to be consistent with the cumulative impacts discussion in the last paragraph of page H-67, which states that "Given the absence of grouse, and the limited quantity and marginal quality of potential grouse habitat in the area, US Department of Agriculture-Forest Service Management Direction guidelines for Management Indicator Species (MIS) do not apply to this project." By looking at sage grouse habitat on a component-by-component basis and mainly on LBA and mining properties, the impacts of the LBA decisions on the health and sustainability of the grouse population in this area are not presented . We note that a full biological assessment and evaluation document is being prepared for review in addition to the information in the Final EIS analysis.

Exhibit 11

Tonnesen, G., Z. Wang, M. Omary, C. Chien, Z. Adelman, and R. Morris, et al., *Review of Ozone Performance in WRAP Modeling and Relevance to Future Regional Ozone Planning*, presentation given at WRAP Technical Analysis Meeting (July 30, 2008)

Review of Ozone Performance in WRAP Modeling and Relevance to Future Regional Ozone Planning

Gail Tonnesen, Zion Wang, Mohammad Omary, Chao-Jung Chien
University of California, Riverside

Zac Adelman
University of North Carolina

Ralph Morris et al.
ENVIRON Corporation Int., Novato, CA

Ozone Planning Needs

- New 75 ppb eight-hr average NAAQS for ozone will result in increased number of ozone non-attainment areas and the need for new ozone SIPs.
- New ozone non-attainment areas will be located in western states including rural and remote regions.
- To what extent can previous WRAP visibility modeling be used to assist in ozone planning?

White Paper on WRAP Ozone Modeling

- Review ozone performance in WRAP regional scale visibility modeling.
- Assess suitability of 2002 Base Case and 2018 WRAP model results for use as boundary conditions for future high resolution ozone model simulations.
- Recommend updates and boundary condition values to be used in future ozone modeling studies.

Modeling Needs for Ozone

- Must use photochemical air quality models (CMAQ, CAMx) for ozone SIPs to address several issues:
  - Need to address both 1-hr and 8-hr average.
  - Control strategies might differ in urban versus rural areas.
  - Contributors to ozone include:
    - International transport.
    - Regional transport.
    - local photochemical production: natural & anthropogenic
    - Stratospheric intrusion.

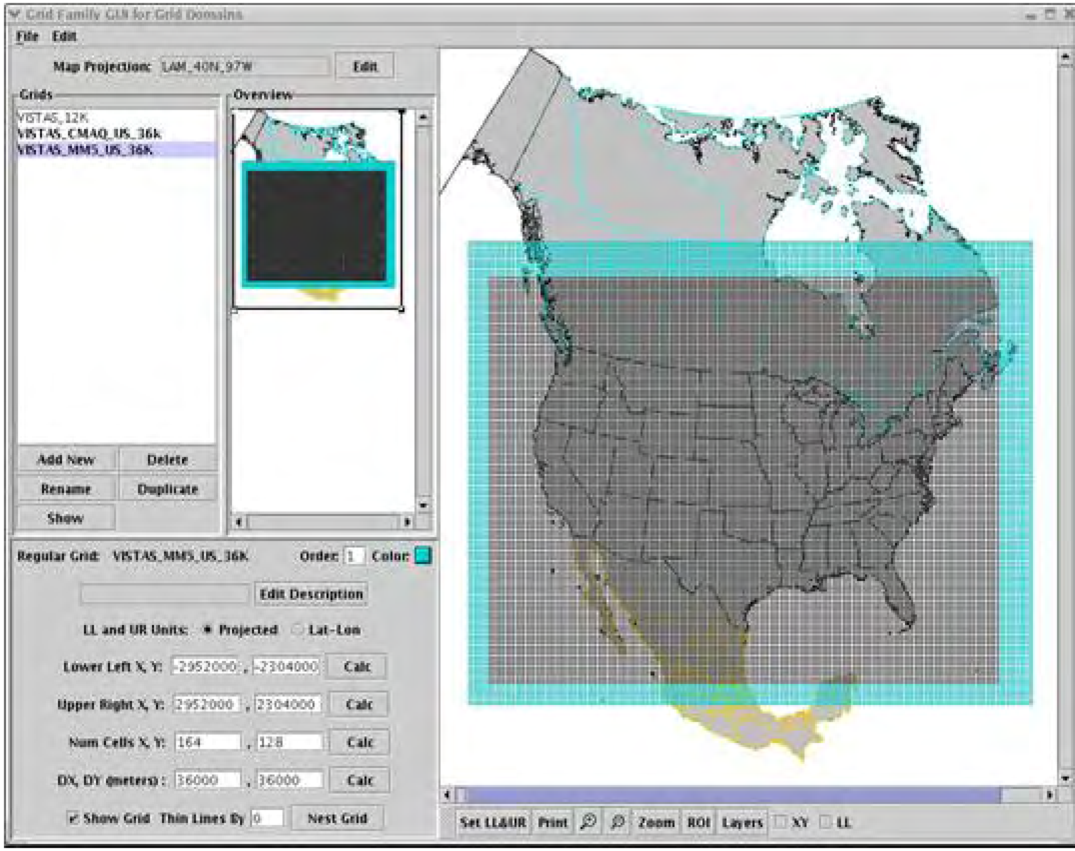
Previous WRAP Ozone Modeling

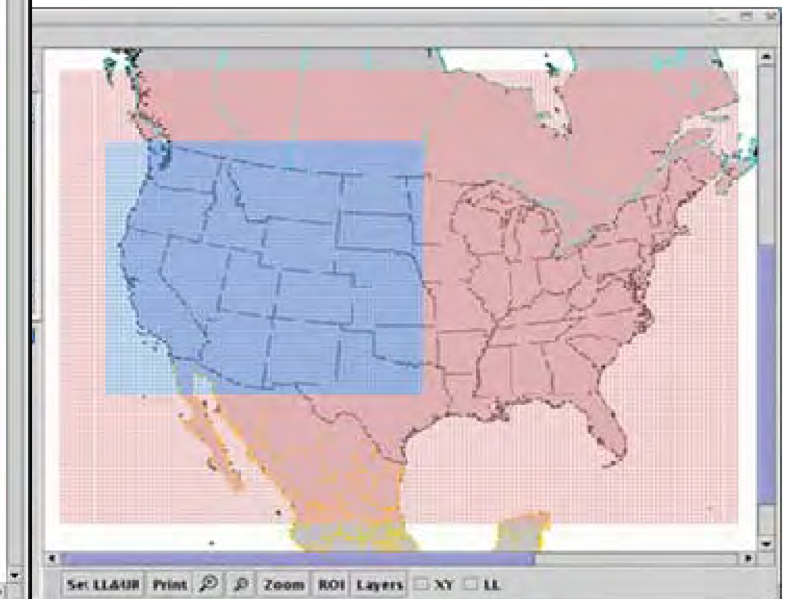
- All WRAP CMAQ and CAMx visibility modeling included modeling of ozone:
  - Ozone and other oxidants effect the formation of secondary PM2.5 species sulfate, nitrate and OC. Gas phase NO2 affects visibility directly.
  - Limited evaluation of ozone performance because regional ozone levels have small uncertainty compared to other input data.

WRAP Visibility Modeling Cases

- 2002 Base version B used for the model performance evaluation (MPE):
  - Full year for 36 km model.
  - Selected months for 12km for 2002 Base version A.
- Planning Cases include:
  - 2002 planning case using typical baseline period emissions (Plan02d).
  - 2018 base case that includes "on the books" emissions reductions (Base18b).
  - Preliminary Reasonable Progress (PRP18a).

Modeling Domain





WRAP 36-km CMAQ/CAMx Domain within MM5 36-km domain

WRAP CMAQ domain: red: 36-km blue: 12-km

Review of Previous Ozone MPE

- AQS gas phase data includes ozone data at 249 sites in the western US in 2002.
- Most of the sites in the AQS are for urban influenced sites.
- Some urban sites also include NO2, CO, HC, SO2.
- **We do not expect the 36 km model to perform well for urban areas because of grid resolution.**
- Limited gas phase data available at rural and remote sites – need more rural gas species monitoring.

Model Performance Approach

- Time-series plots of model and observed data.
- Spatial plots of model and data.
- Mean error and bias performance metrics.

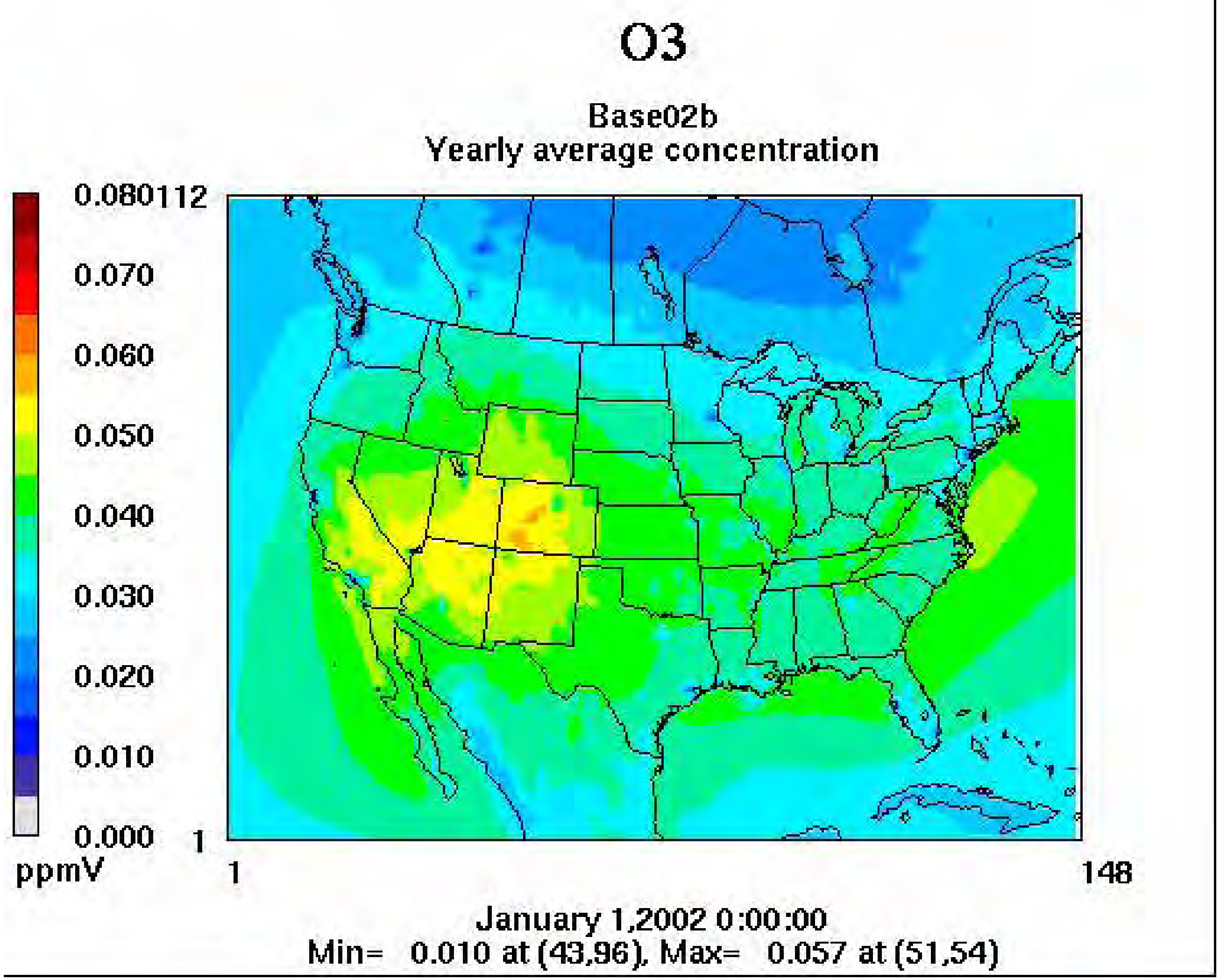
MPE Results available at:

www.cert.ucr.edu/aqm/308/cmaq.shtml

#base02aV4512kvs36k

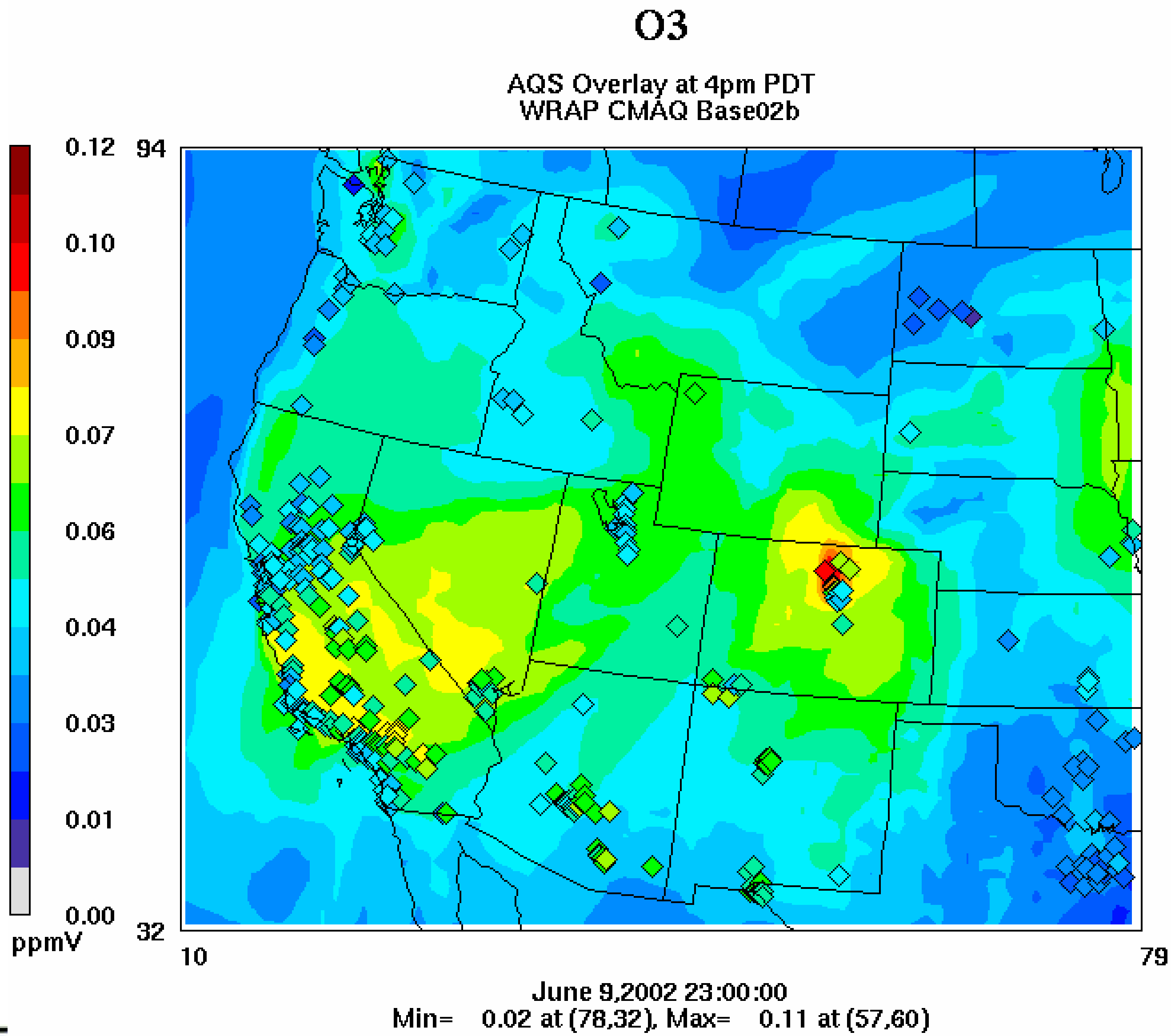
#base02bvsbase02a36k

2002 Model Annual Average Ozone

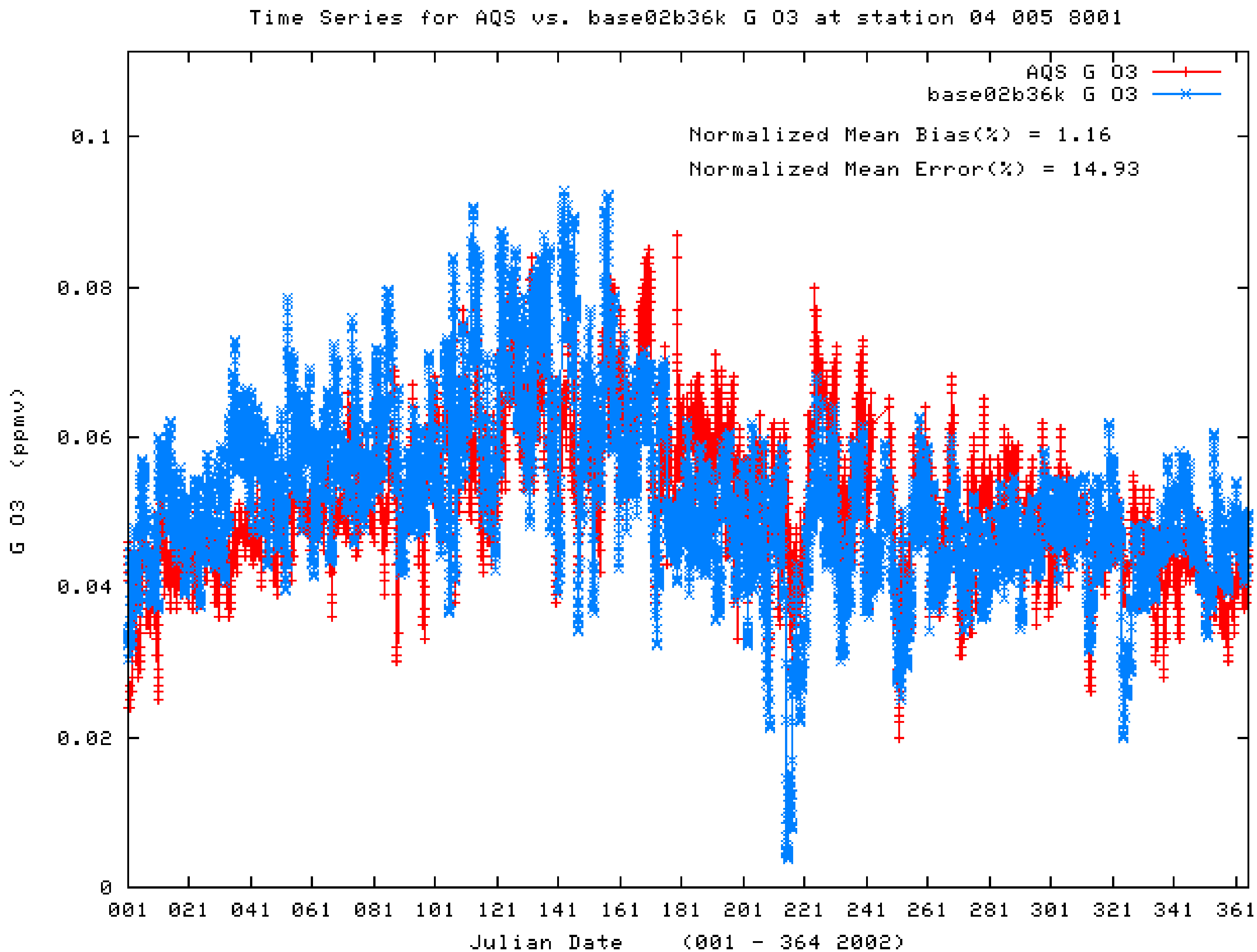


ENVIRON UCR UNC CAROLINA ENVIRONMENTAL PROGRAM

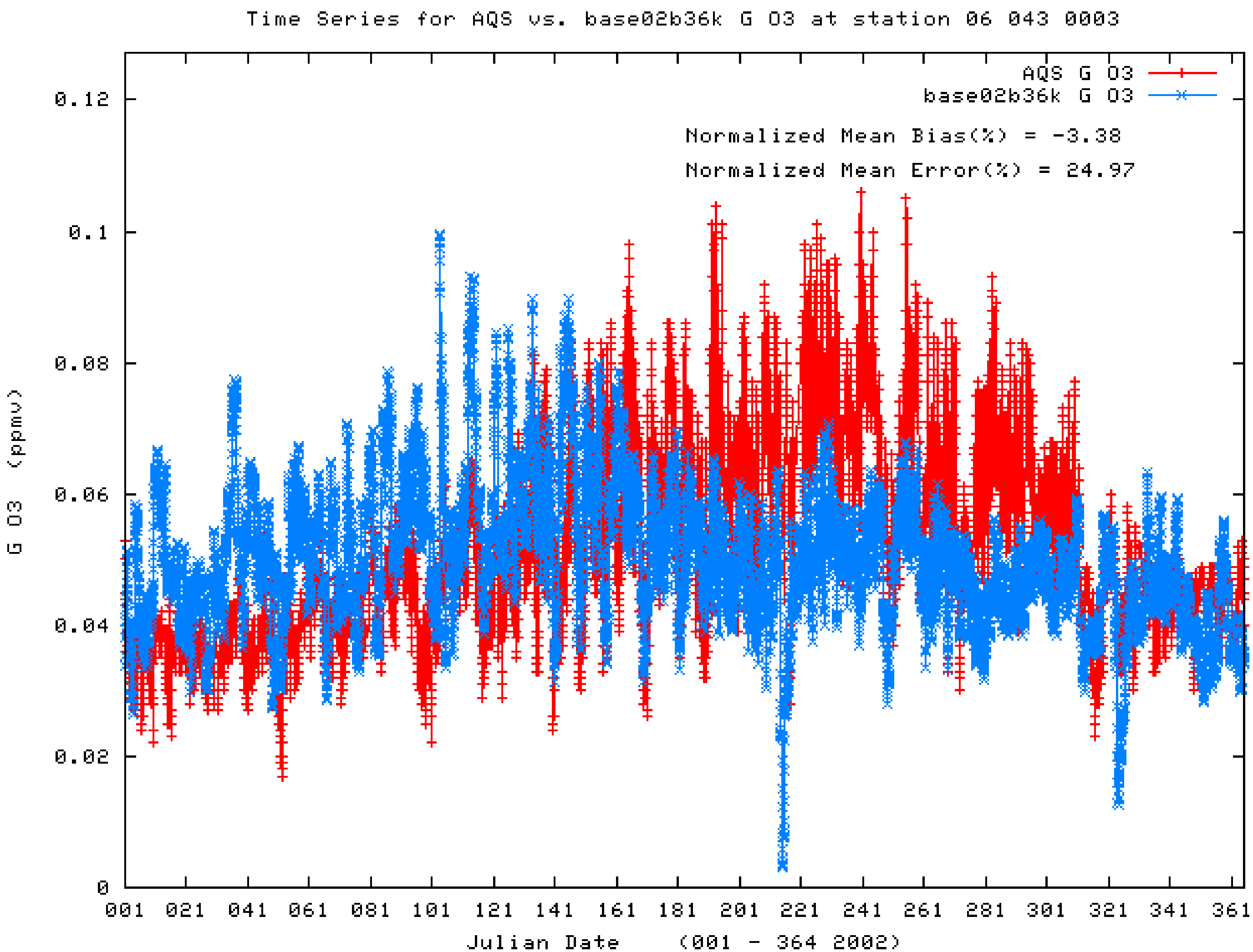
Daily comparisons at 4 pm PDT: June 9, 2002



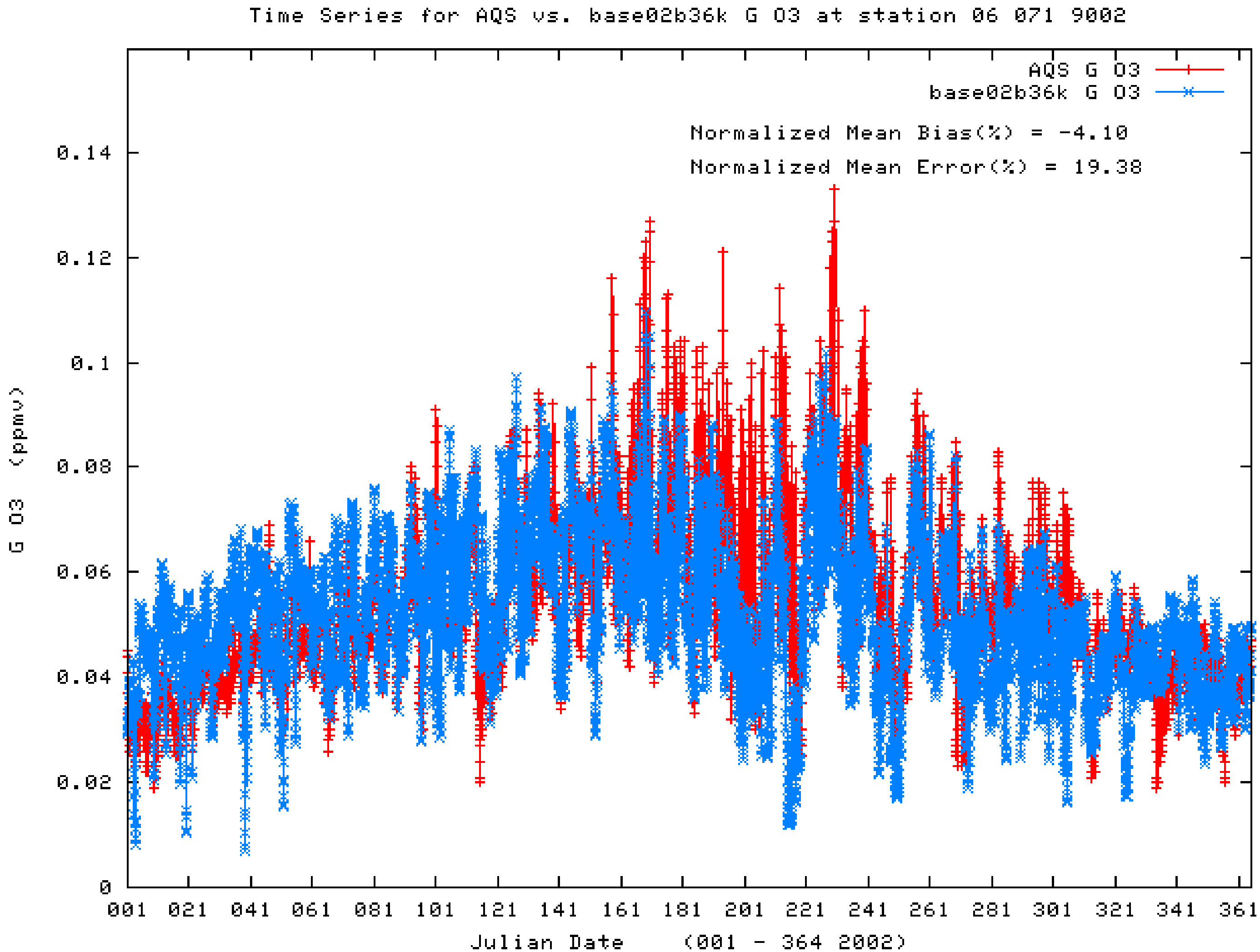
Annual O3 Time-series: Grand Canyon NP



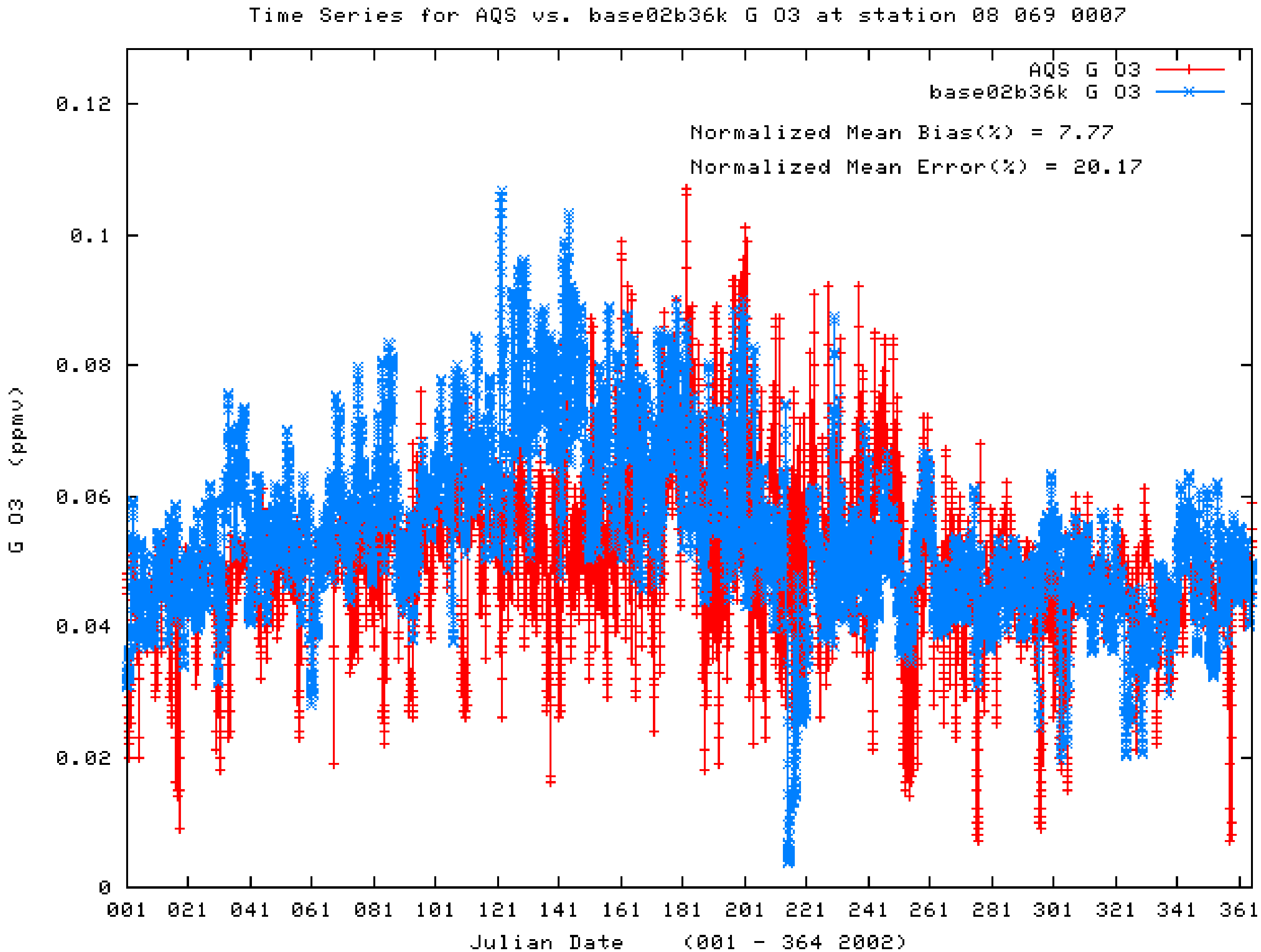
Annual O3 Time-series: Yosemite NP



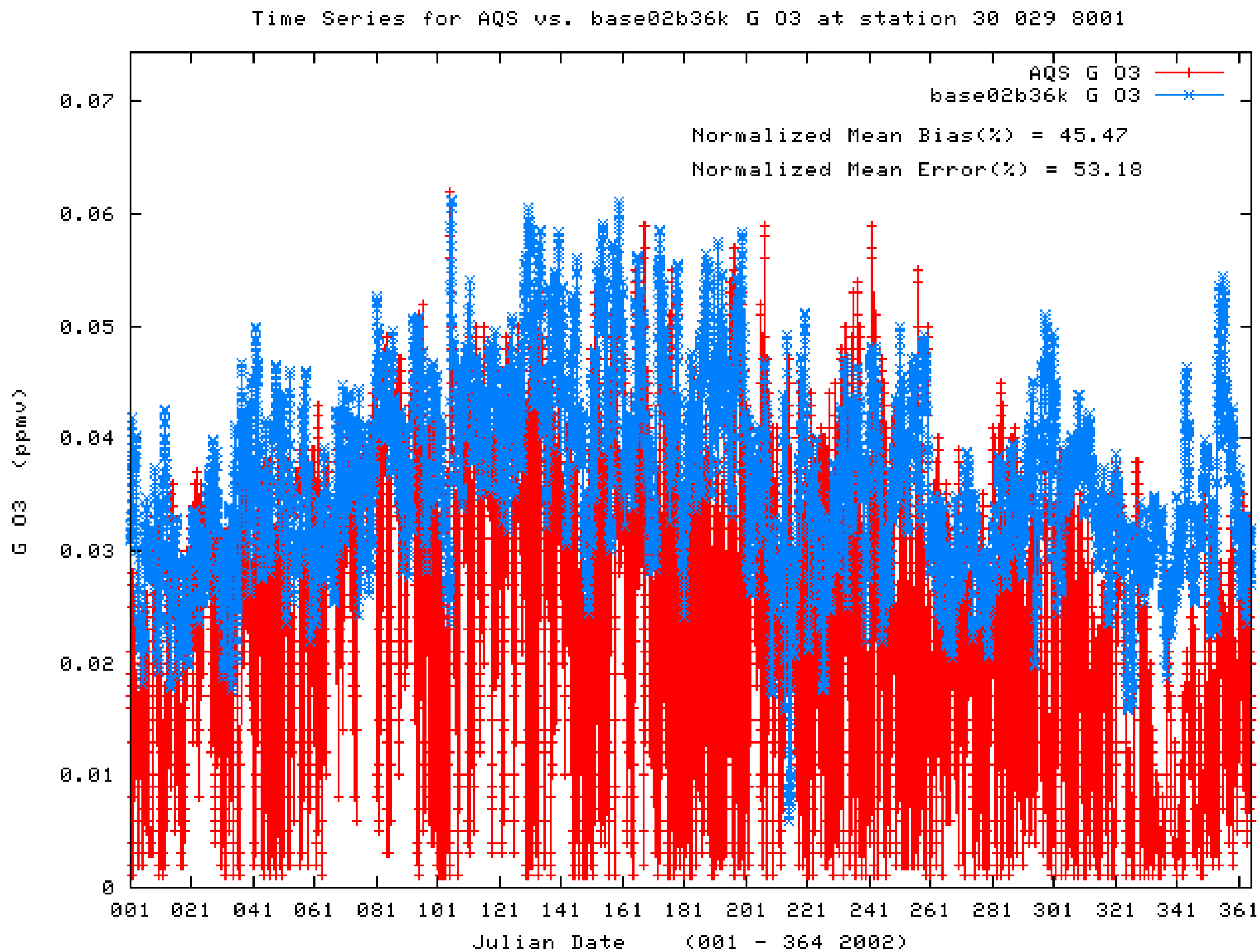
Annual O3 Time-series: Joshua Tree



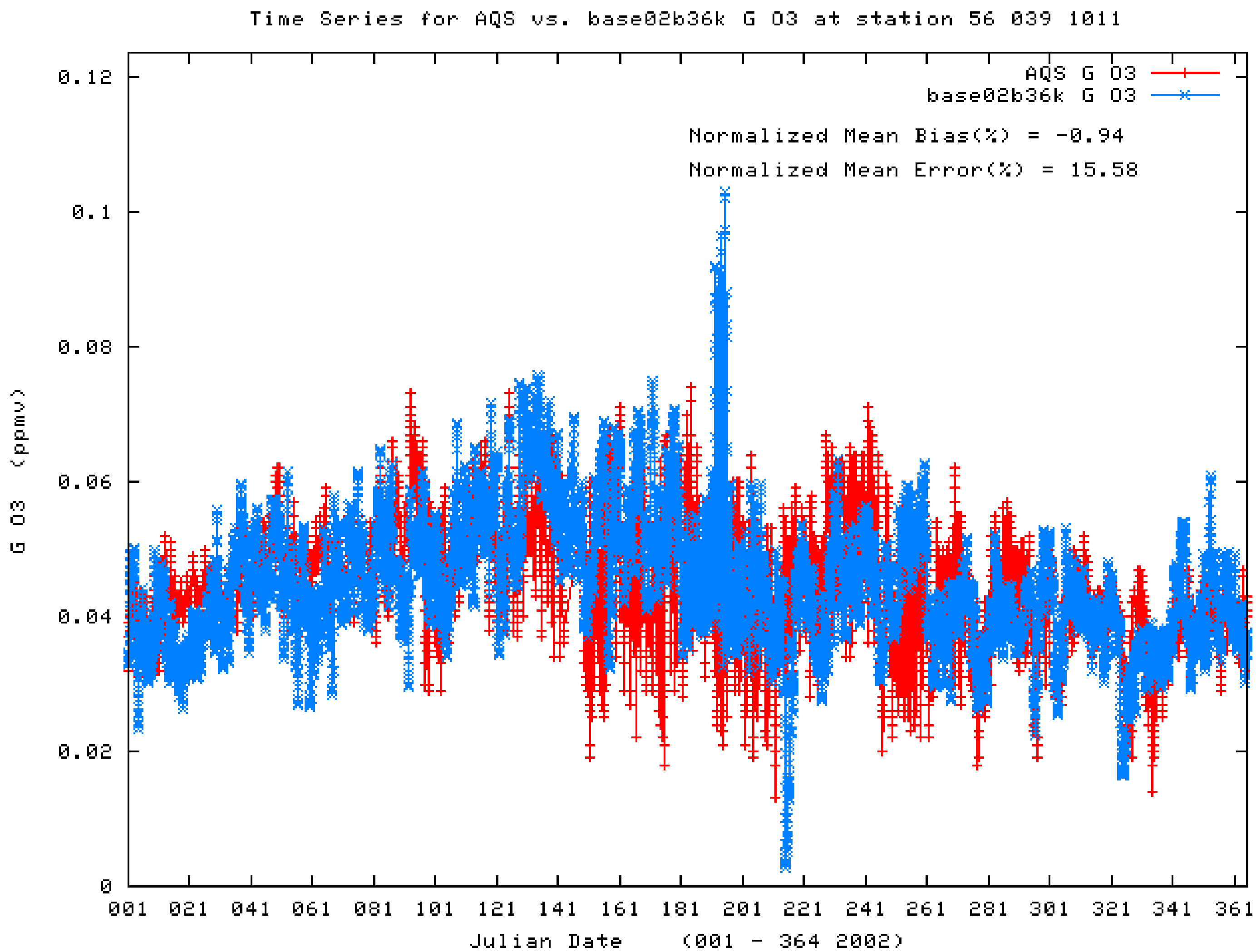
Annual O3 Time-series: Rocky Mountain NP



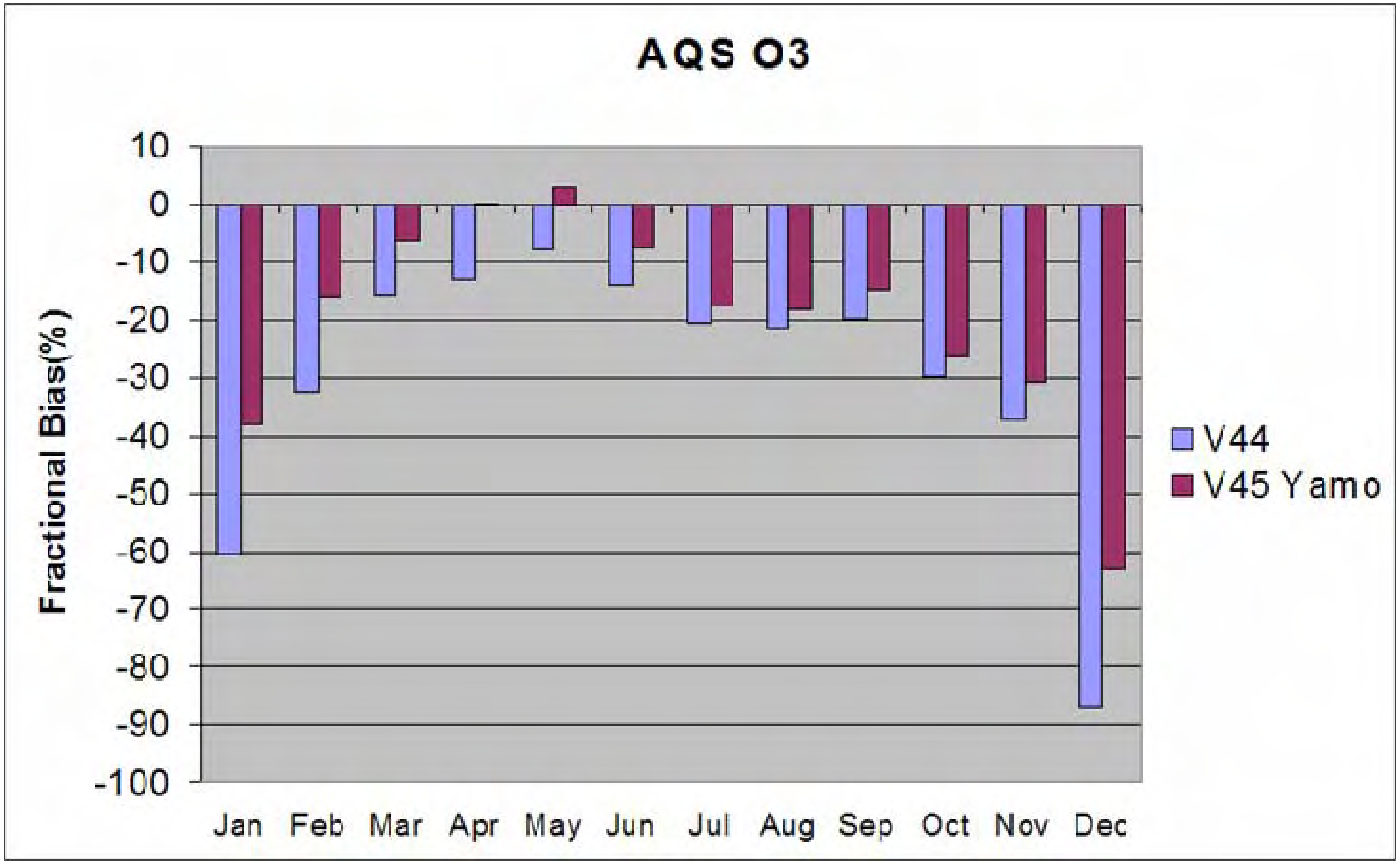
Annual O3 Time-series: Glacier NP



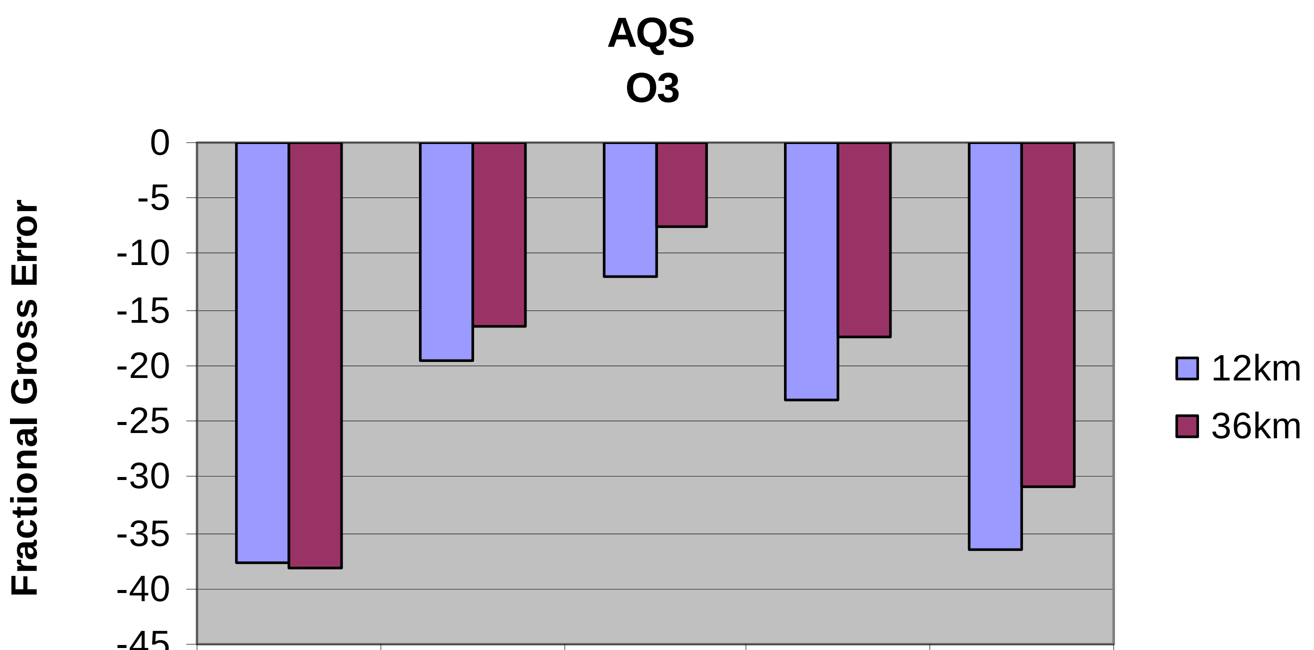
Annual O3 Time-series: Yellowstone NP



Tabulated Fractional Bias and Error
(using 60 ppb filter for observed data)

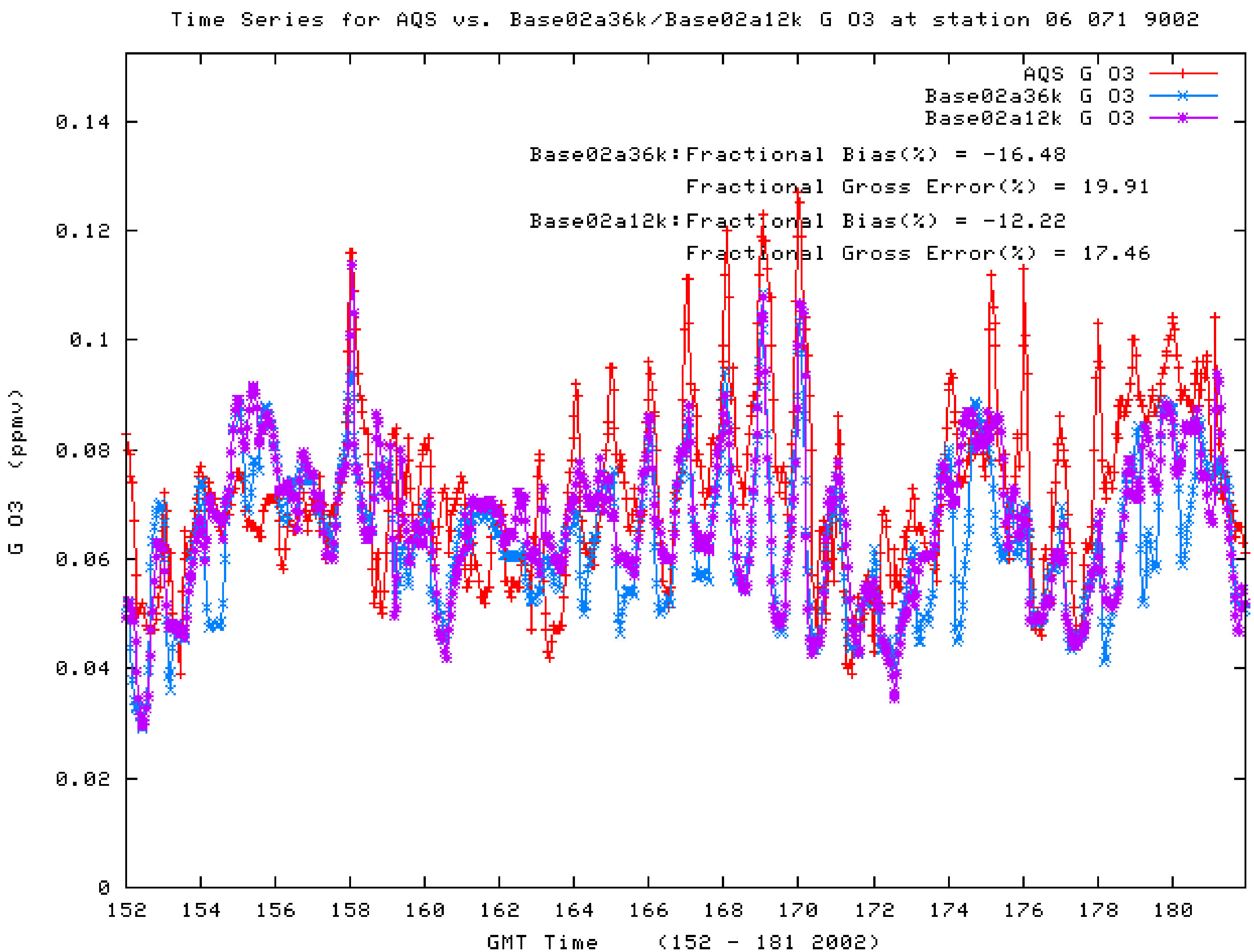


Tabulated Fractional Bias and Error
(using 60 ppb filter for observed data)



	January	February	June	July	November
12km	-37.7	-19.5	-12.1	-23.2	-36.5
36km	-38.1	-16.4	-7.5	-17.5	-30.9

Ozone 36km vs. 12km: Joshua Tree



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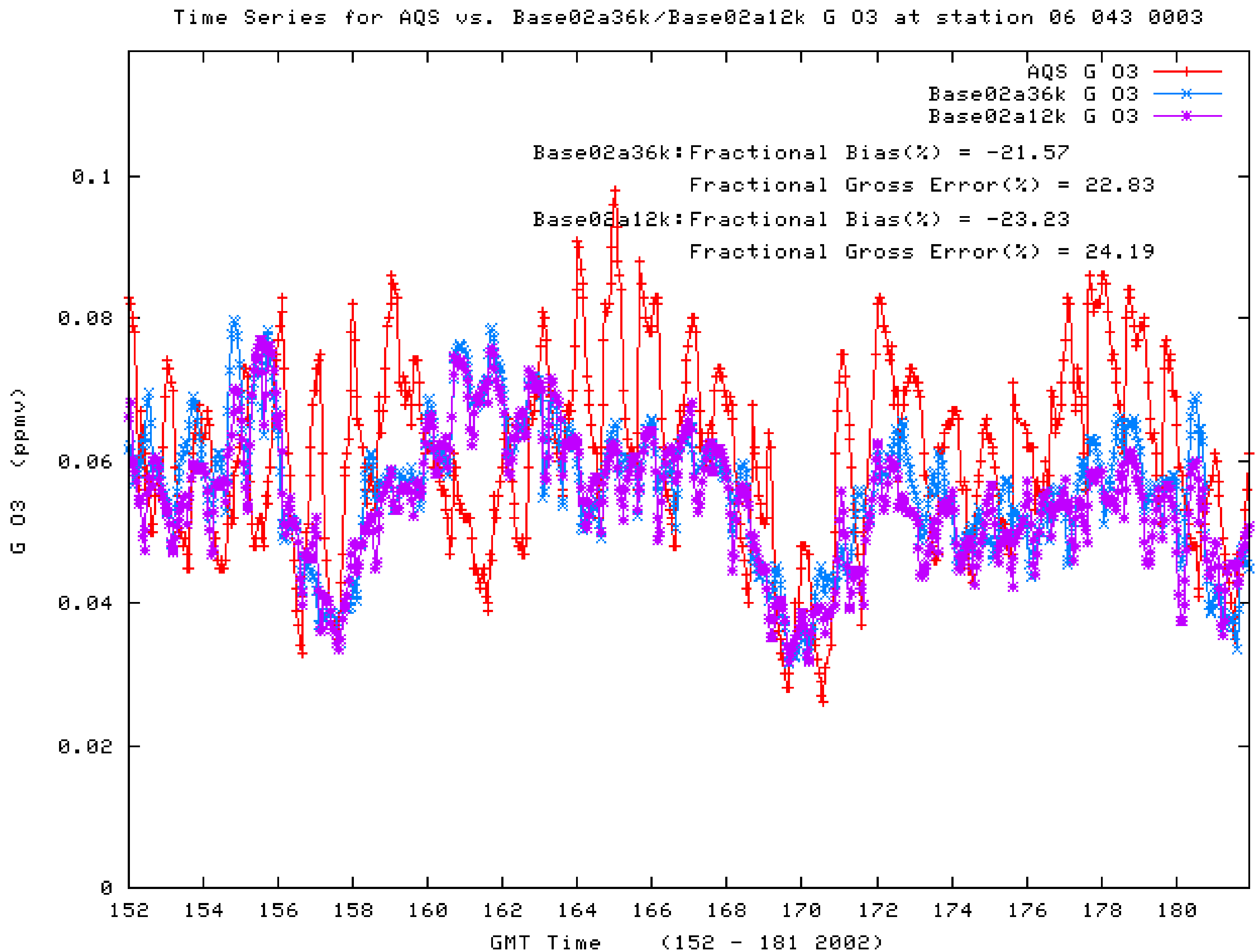
Ozone 36km vs. 12km: Yosemite NP



ENVIRON

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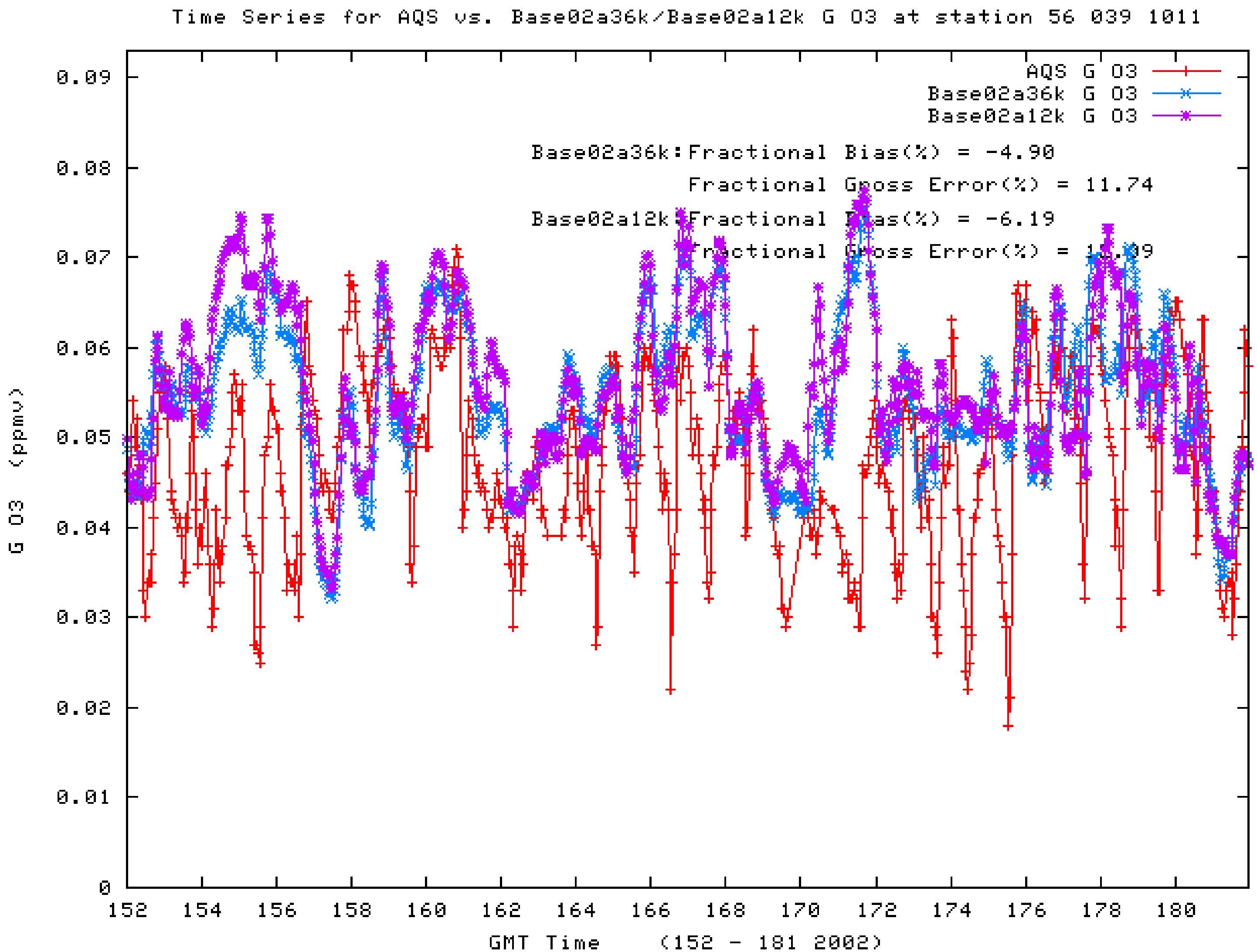
UNC CAROLINA ENVIRONMENTAL PROGRAM

Ozone 36km vs. 12km: Yellowstone NP



Summary for Ozone MPE

- Limited monitoring data available for rural and remote sites.
- 12km model was not superior to 36km model.
- CMAQ performed well for ozone for remote sites (although data for MPE was very limited).
- Tabulated metrics shown above are not appropriate for rural ozone MPE because of 60 ppb filter and the predominance of urban sites.

Future Needs for Ozone MPE

- Need to identify rural and upwind urban sites in AQS database for more complete MPE, and need to add new monitoring sites.
- Explore use of satellite data for ozone, NO2 and other gas species.
- Need aloft measurements and ocean aloft measurements to better characterize transport.
- Develop new metrics for MPE that do not employ the 60 ppb ozone filter.

Projected Ozone for 2018

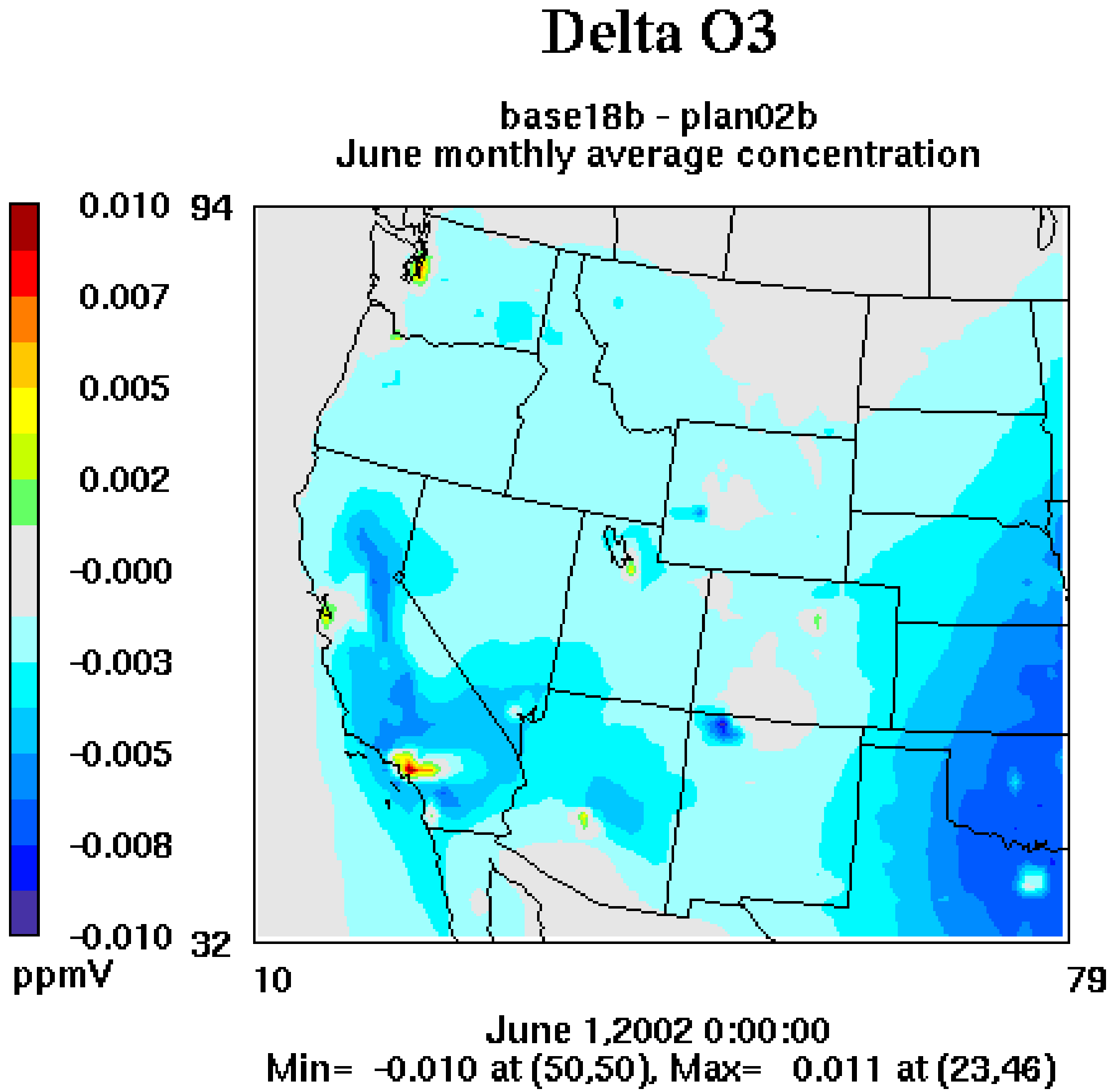
- Compare Base 2018 Base Case and 2018 Preliminary Reasonable Progress Case to the 2002 Planning Case for benefits on ozone reduction.
- Results available on RMC webpage:

  www.cert.ucr.edu/aqm/308/cmaq.shtml

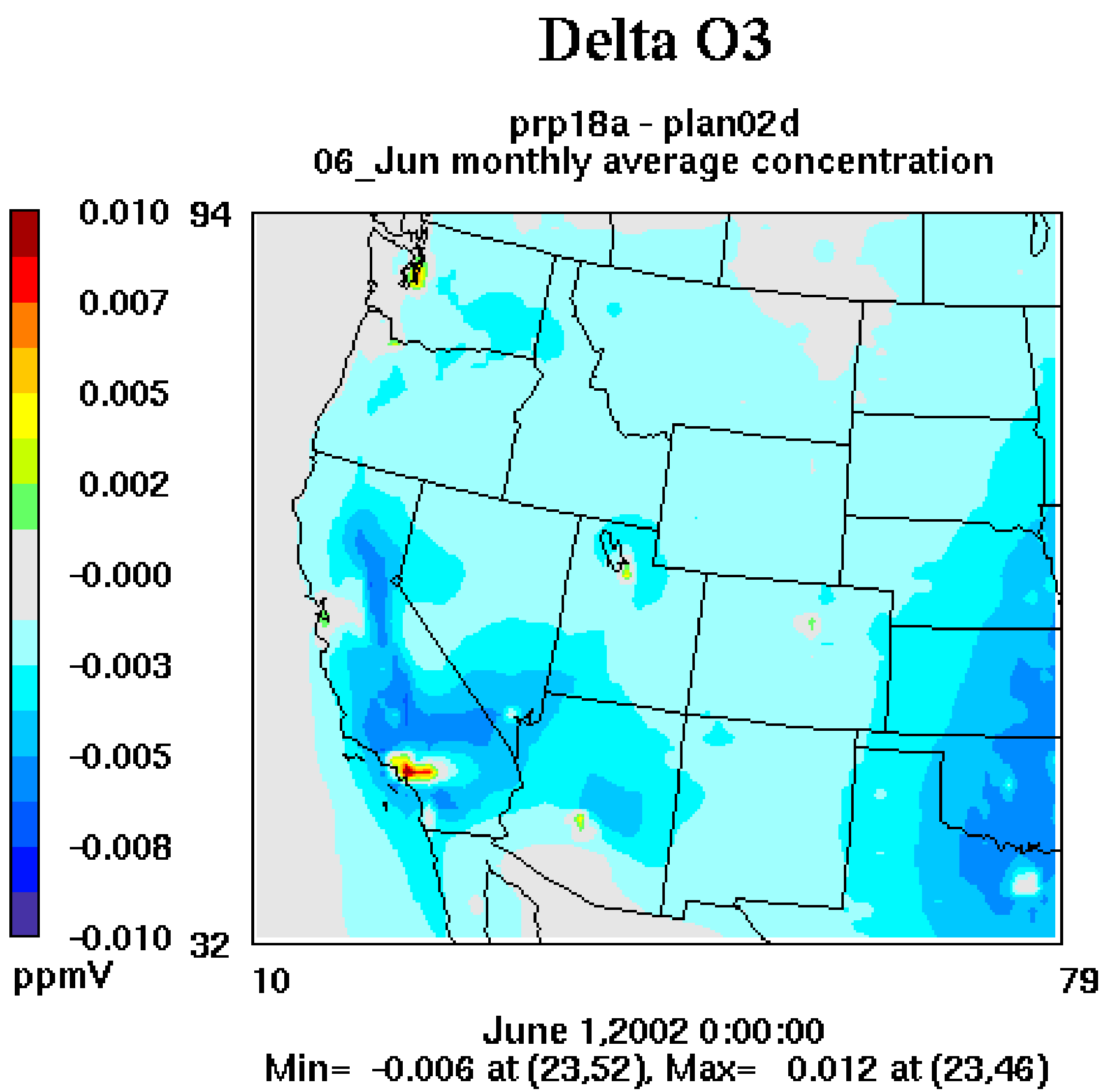
  #base18bvsplan02b

  #prp18avsplan02d
- Results include daily average, monthly average and annual average spatial difference plots.

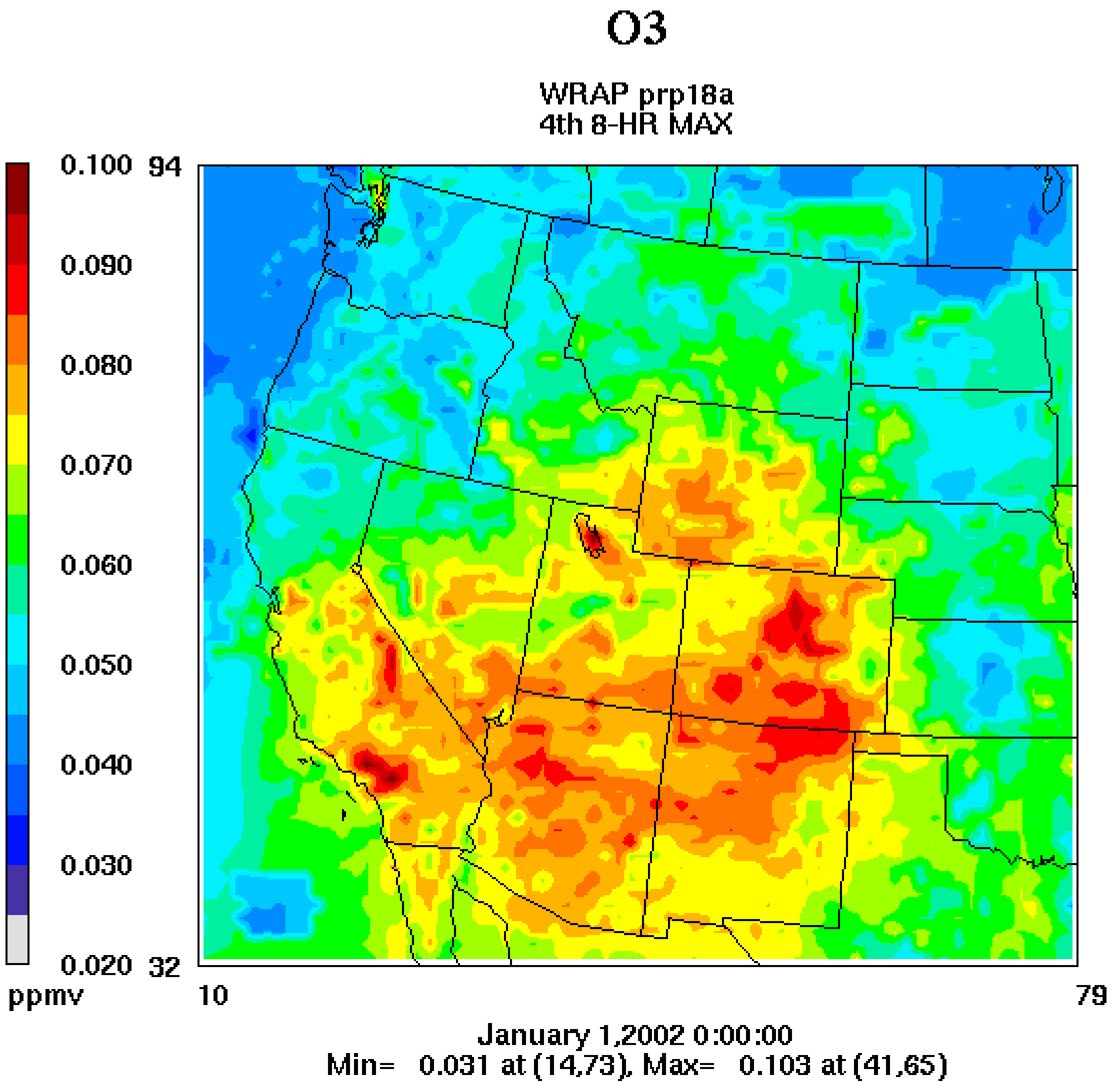
Projected June average ozone change for 2018 base case



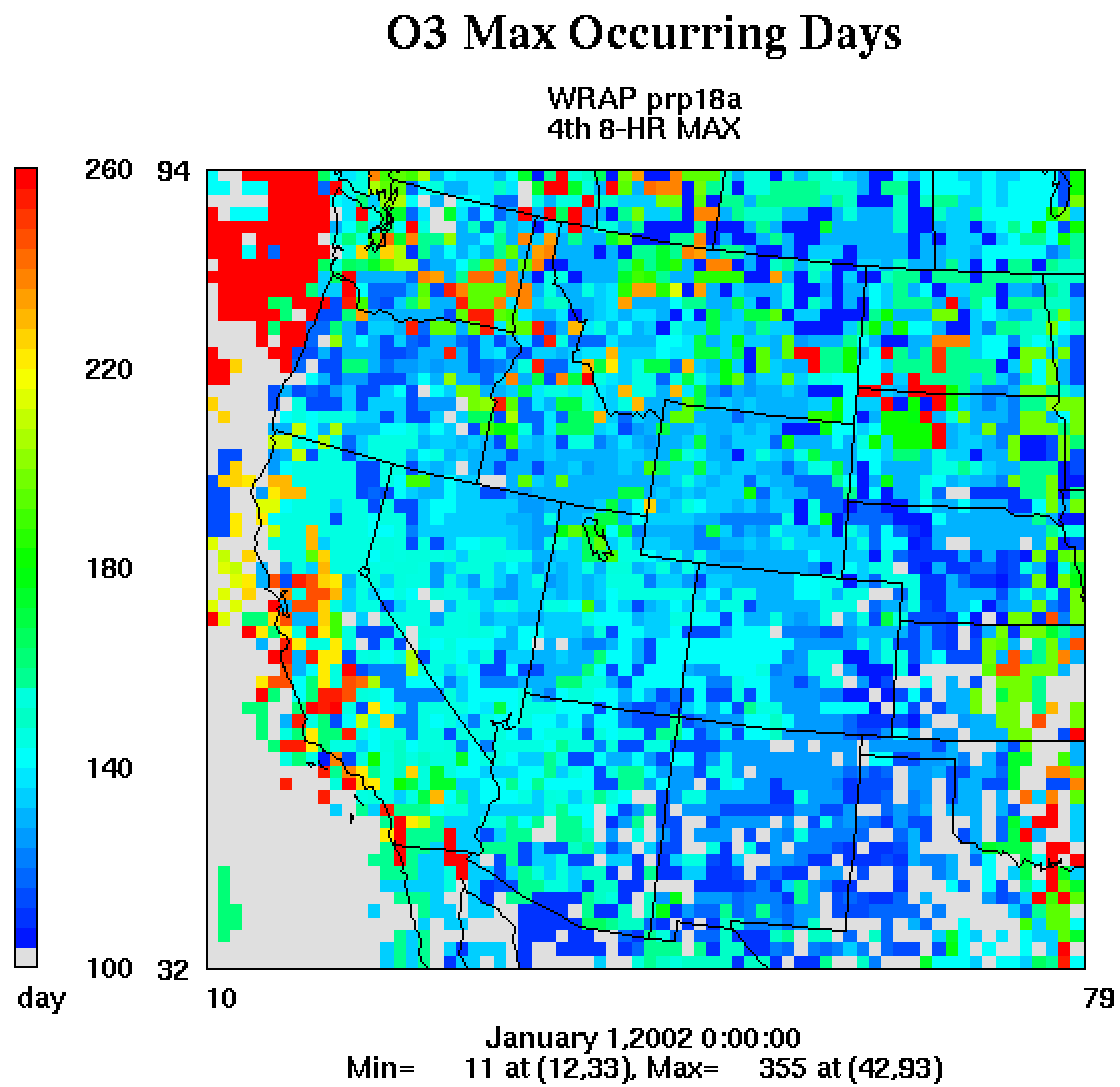
Projected June average ozone change for 2018 PRP case



Projected 4st Max 8-hr average ozone for 2018 PRP case



Projected 1st Max 8-hr average ozone for 2018 PRP case



Summary of 2018 Ozone Predictions

- Reductions in monthly average ozone of 1 to 10 ppb during summer in 2018 Base Case.
- Slightly larger reductions in 2018 PRP case.
- PRP18a case predicts exceedence of the 8-hr average ozone standard in much of the southwestern US, mostly in spring.
- Likely that there is large contribution from tranported ozone.
- Need to re-evaluate GEOSCHEM ozone BC.

Uncertainties in Input Data

- Emissions data – largest uncertainty, ranges from 30% to a factor of 3 depending on source category. WRAP made significant improvements in emissions, largest uncertainties remain in biogenic VOC, and NH3.
- Meteorology, vertical mixing and PBL height – can have large effect on model performance, especially for urban areas. Need to compare MM5 and WRF.
- Boundary conditions – we have pretty good BC estimates from GEOSCHEM. Larger uncertainty in ozone at model top and in the future BC and transport.
- Uncertainty related to future climate – probable increases in biogenic VOC and in reactivity.

Uncertainties in Model Science

- Photochemical mechanisms – gas phase ozone chemistry is best for rural low NOx conditions. Mechanisms underestimate reactivity for urban high NOx conditions.
- Heterogeneous and aqueous chemistry – potentially largest uncertainty affecting regional ozone formation. Large uncertainty in NOx budget and fate of NOx (N2O5 hydrolysis, renoxification, HOx radical budgets).
- Grid resolution effects – artificial dispersion might over estimate ozone formation in areas with large emissions. Also makes MPE more difficult. Nested grids in CAMx can better handle urban ozone budgets.

Applications of WRAP data

- Existing planning cases and 2002 base case are useful for evaluating ozone in rural & remote areas.
- Sensitivity studies can be performed to estimate effects of boundary conditions and sensitivity to emissions controls, either across the board emissions reductions or by source category.
- Data can be extracted from 2002 base case to create BC for new, high resolution 4-km ozone modeling.

Ozone Sensitivity to VOC and NOx

- Ozone can be reduced by controlling both VOC and NOx.
- Urban ozone in the west is more sensitive to VOC control, while NOx controls can have both benefits and transient dis-benefits for urban ozone. (There is no NOx dis-benefit for urban ozone if NOx reductions are sufficiently large.)
- Rural ozone is more sensitive to NOx controls.
- Ozone sensitivity to VOC and NOx reductions can be estimated directly using ambient indicator ratios (although data is limited) and using model sensitivity simulations.

Ozone Production Efficiency per NOx

- Ozone produced per molecule of NOx emissions varies considerably – less efficient ozone production at low VOC/NOx ratios and at higher VOC and NOx concentrations because NOx is more rapidly converted to inert HNO3:
  - Power plant plumes: 1-3 molecules O3 per NOx
  - Urban conditions: 4-10 molecules O3 per NOx
  - Rural conditions: 10-100 molecules O3 per NOx
- Much greater benefit of controlling mobile and areas sources of NOx in rural areas for an equivalent mass reduction.

Recommended Model Updates

- New emissions data should be included in future CMAQ or CAMx runs: MEGAN biogenic model; new oil & gas inventory; lightning NOx emissions.
- Should use updated model versions and updated chemistry, new CB-05 or new SAPRC07, if available.
- Updated global simulations for present and future BC.
- Need to save 3-d concentration files in all future runs.
- Long-term needs:
  - More ambient monitoring of gas species.
  - Advances in science of NOx budget and fate.

Exhibit 12

U.S. EPA, Comments on Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Sublette County, Wyoming (February 14, 2008)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

February 14, 2008

Ref: EPR-N

Mr. Robert A. Bennett, State Director
Bureau of Land Management
Wyoming State Office
5353 Yellowstone Road
Cheyenne, Wyoming 82009

Re: Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project
Sublette County, Wyoming CEQ #20070542

Dear Mr. Bennett:

In accordance with our responsibilities under Section 102(2)(C) of the National Environmental Policy Act (NEPA), 42 U.S.C. Section 4332(2)(C), and Section 309 of the Clean Air Act, 42 U.S.C. Section 7609, the U.S. Environmental Protection Agency Region 8 (EPA) has reviewed the Revised Draft Supplemental Environmental Impact Statement for the Bureau of Land Management's (BLM) proposed Pinedale Anticline Oil and Gas Exploration and Development Project (Revised Draft SEIS). The Revised Draft SEIS provides additional alternatives and impacts analyses in response to changes to the preferred alternative and to comments received on the December 2006 Draft SEIS.

The Revised Draft SEIS supplements a previous EIS and a 2000 Record of Decision authorizing up to 700 producing wells in the Pinedale Anticline Project Area (PAPA). The Revised Draft SEIS assesses both the site-specific and cumulative environmental impacts of year-round drilling, completions, and production of up to 4,399 additional natural gas wells on up to 12,885 acres of new disturbance. The year-round drilling is proposed within certain areas of the PAPA that coincide with big game crucial winter habitats and greater sage-grouse seasonal habitats. The PAPA encompasses 198,037 acres and is located directly south of Pinedale, Wyoming, in Sublette County. The Bridger-Teton National Forest is located west, north, and east of the PAPA and comes within 2.3 miles of the PAPA boundary. In addition, the PAPA is located approximately 11 miles west of the Bridger Wilderness Area. The Bridger Wilderness Area is a federal Class I area under the Clean Air Act, requiring special protection of air quality and air quality related values, such as visibility.

The Revised Draft SEIS considers five alternatives in detail. The preferred alternative consists of up to 4,399 additional wells on up to 12,885 acres of new surface disturbance by the year 2025. The drilling and completions within big game crucial winter habitats would occur year-round within concentrated development areas centered in a core area on the Anticline Crest. The Proposed Action also includes installation of a liquids gathering system in the central and southern portions of the PAPA complementing the existing liquids gathering system in the northern portion of the PAPA. Tier 2 equivalent emission controls would be installed on 29 out of 48 drilling rigs at peak drilling in 2009. The proponent's new Proposed Alternative is similar to the Preferred Action in that it consists of the same project components including 4,399 additional wells on up to 12,885 acres of disturbance. However, the core development area considered under the Preferred Alternative is different spatially from the Proposed Action and includes a potential development area (PDA). With the PDA, the Preferred Alternative has the potential for year-round development on 70,200 acres, over 60% greater than the core development area proposed under the Proposed Action. In addition to the Proposed Action and Preferred Alternative, the Revised Draft SEIS considers two other action alternatives that differ primarily in areas where year-round development may occur; installation of liquids gathering systems; and air quality mitigation measures. The Revised Draft SEIS also includes a No Action Alternative, which is based on elements set forth in the 2000 Pinedale Anticline Record of Decision (ROD).

EPA Region 8 has reviewed the Revised Draft SEIS and has three primary concerns, which are briefly highlighted in this letter: air quality impacts to visibility and ozone, and groundwater impacts. The enclosed "Detailed Comments" provides more discussion of our concerns regarding these issues as well as our comments on the proposal's impacts to surface water quality and wetlands.

AIR QUALITY IMPACTS - VISIBILITY

The Revised Draft SEIS discloses the significant and unanticipated impacts to visibility that occurred since implementation of the 2000 Pinedale Anticline ROD. The NO_X emissions from all sources operating in the PAPA in 2005 were five times the analysis threshold set in the 2000 Pinedale Anticline ROD (Revised Draft SEIS, page 3-70). For visibility, the 2005 emissions led to a modeled 45 days of visibility impairment greater than 1.0 deciview (dv) at the Class I Bridger Wilderness Area, 5 days at the Class I Fitzpatrick Wilderness Area, and additional days at other regional Class I areas (Revised Draft SEIS, page 3-73). Under the No Action scenario (ie., where development occurs under the provisions of the 2000 ROD) predicted 2007 visibility impacts are even higher than the 2005 predictions, with 62 days above 1.0 dv at Bridger Wilderness Area, 8 days at Fitzpatrick Wilderness Area, and additional days at other regional Class I and sensitive Class II areas (Revised Draft SEIS, page 4-78). Given the unforeseen and significant impacts that have occurred from the development of the 642 producing oil and gas wells approved under the 2000 Pinedale Anticline ROD, EPA recommends the Revised Draft SEIS identify effective and enforceable mitigation strategies to ensure environmental protection as the proposed 4,399 additional wells on the Pinedale Anticline are developed. EPA also recommends the Revised Draft SEIS provides a plan to mitigate the significant air quality environmental impacts resulting from the existing oil and gas development on the PAPA.

EPA and the Wyoming Department of Environmental Quality (WDEQ) participated on the Air Quality Stakeholders group that provided early guidance and comments to the BLM on the air quality modeling and visibility mitigation plan included in the December 2006 Draft SEIS. The air quality analysis and a substantial part of the visibility mitigation plan negotiated for the December 2006 Draft SEIS have been carried forward to this Revised Draft SEIS. However, the mitigation plan included in this Revised Draft SEIS includes significant modifications of the original commitments. EPA is concerned these modifications weaken the plan's ultimate goal and create uncertainty about achieving the ultimate goal of zero days of visibility impairment at Bridger Wilderness Area. The modified commitments suggest reluctance to commit to the full mitigation plan and have eroded EPA's confidence that the goal of zero days will be achieved. Without further specificity on how the ultimate goal will be achieved, EPA believes that the proposed project will result in at least ten days of visibility impairment at the federal Class I Bridger Wilderness Area. EPA considers ten days of visibility impairment greater than 1.0 dv a significant, adverse impact to air quality.

AIR QUALITY IMPACTS - OZONE

The Revised Draft SEIS updates the ozone analysis with a current state-of-science photochemical grid model. This level of analysis is particularly important given the elevated ozone levels that have been recorded at ambient air monitoring stations neighboring the PAPA. The BLM modeling analysis predicts ozone concentrations approaching EPA's current National Ambient Air Quality Standard (NAAQS). Specifically, ozone concentrations for the Proposed Action are predicted to be 0.0782 ppm near the PAPA. For Alternative C with the 80 percent reduction in drill rig emissions, ozone concentrations are predicted to be 0.0765 ppm near the PAPA (Alternative C is similar to BLM's Preferred Alternative). However, the Revised Draft SEIS does not provide analysis of ozone concentrations for the first five years prior to full implementation of the 80 percent reduction in drill rig emissions under the Preferred Alternative air quality mitigation strategy. The performance evaluation of the photochemical model supported the model's reliability in predicting ozone but also noted a small underestimation bias. With predicted ozone concentrations approaching the current standard and an underestimation bias in the model, EPA is concerned about the potential environmental and health impacts associated with the projected 0.0782 and 0.0765 ppm ozone concentrations. This concern is further substantiated by the elevated ozone concentrations above the current 0.08 ppm standard recorded at ambient air monitoring stations near the PAPA in 2005 and 2006. In addition, natural gas development and production under the Preferred Alternative is anticipated to continue until 2065.

In view of the ozone levels monitored, modeled and predicted, EPA recommends that an air quality mitigation strategy be developed to address these potentially significant air quality and health impacts. The SEIS should also include modeled demonstrations that the proposed action will not incrementally contribute to violations of a NAAQS. In addition, EPA is currently reviewing the national primary and secondary standards for ozone. This project may be affected if EPA determines that a revision to the current ozone standard is necessary and appropriate. Consequently, EPA may have further comments on the project's ozone analysis after the final rule is issued.

GROUNDWATER

The Revised Draft SEIS includes important new information on groundwater monitoring in the PAPA. The monitoring data suggest that current drilling and production activities on the PAPA have contributed to contamination of an aquifer used as a drinking water source. Existing benzene contamination exceeding the Drinking Water Standard (maximum concentration level or MCL) in two wells was attributed to oil and gas exploration activities in the Revised Draft SEIS. Further, benzene and other hydrocarbons have been detected in 88 of the approximately 230 water supply wells monitored. The Revised Draft SEIS does not disclose the monitored concentrations; it is, therefore, unknown how much the monitored concentrations are above or below the MCL. Based upon the extent of contamination of these two wells completed in an aquifer used as a source of drinking water and benzene contamination in approximately one third of the other wells monitored, EPA is concerned about the significance of existing and potential future impacts associated with activities in the PAPA. EPA believes that such impacts are environmentally unsatisfactory.

The Revised Draft SEIS provides only raw data. EPA believes the Revised Draft SEIS does not provide an adequate analysis of the effects of the expanded well field on groundwater; nor does it discuss the potential effectiveness of the proposed mitigation measures. Although the 2000 Pinedale Anticline ROD required all wells within one mile of proposed development be monitored on an annual basis, there is no documentation of how many wells exist within this defined buffer area nor can it be documented that monitoring took place in the defined areas. The Wyoming State Engineer has identified 4000 points of use within the PAPA. While some of these points of use may be duplicates, monitoring has taken place in only approximately 230 wells. The full extent of the benzene and hydrocarbon contamination in the PAPA has not been comprehensively evaluated. Although there are distinct aquifers in this area described in the Revised Draft SEIS, information on impacts and potential mitigation measures were generalized across all of the aquifers. Further, the Revised Draft SEIS acknowledges the source of the widespread low concentration detections (lower than the MCL) is not known (Revised Draft SEIS, page 3-85). EPA recommends that a more clear understanding of the extent of the benzene and hydrocarbon contamination, the aquifers, and the source of contamination is needed to develop effective mitigation measures.

The Revised Draft SEIS provides mitigation measures intended to reduce impacts to groundwater. These measures, however, were not identified as necessary nor were they evaluated as to their effectiveness in any of the alternatives. As the source of the widespread contamination remains unclear, it is difficult to identify and implement appropriate and effective mitigation measures to protect valued groundwater supplies. EPA recommends that where impacts have occurred or may reasonably be expected to occur to groundwater sources as a result of oil and gas production, including but not limited to hydraulic fracturing practices, an effective and enforceable mitigation plan should be developed. The mitigation plan could specifically include plans for replacement of quality water to water users if necessary.

EPA's RATING

Consistent with section 309 of the Clean Air Act, it is EPA's responsibility to provide an independent review and evaluation of the potential environmental impacts of this project. In accordance with our policies and procedures for reviews under NEPA and Section 309 of the Clean Air Act, EPA is rating this Revised Draft SEIS as "Environmentally Unsatisfactory – Inadequate Information" (EU-3) because our review has identified significant, adverse, long-term impacts to air quality and groundwater quality. The "EU" rating is based on potential adverse impacts to visibility in federal Class I areas without adequate mitigation; the extent of groundwater contamination in the PAPA where development has already occurred; and EPA's concern about further potential groundwater contamination impacts that may occur with the proposed project. Some of this contamination exceeds National Drinking Water Quality Standards. In addition, EPA is currently reviewing the national primary and secondary standards for ozone. This review will be completed by March 12, 2008. Should the ozone standard be revised, EPA may have additional comments on the SEIS and project. These impacts are of sufficient magnitude that the proposed action should not proceed as proposed. Further, the "EU" rating makes this project a candidate for referral to the Council on Environmental Quality (CEQ) if the unsatisfactory impacts we identified are not resolved. The rating of "3" is based on the lack of adequate information to characterize existing groundwater contamination or the extent of potential groundwater impacts from the proposed action. The Revised Draft SEIS also does not contain adequate analyses from air quality modeling to disclose the predicted ozone concentration under varying emission scenarios. This "3" rating indicates EPA's belief that the Draft EIS is not adequate for purposes of our 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. The "3" rating also makes this project a potential candidate for referral to CEQ. In addition to EPA's detailed comments on the Revised Draft SEIS, a full description of EPA's EIS rating system is enclosed.

If you have any questions regarding our comments or this rating, please contact Larry Svoboda, Region 8 NEPA Program Director, at 303-312-6004, or Carol Campbell, Acting Assistant Regional Administrator of Ecosystems, Protection and Remediation at 303-312-6340.

Sincerely,

/signed/

Robert E. Roberts
Regional Administrator

cc: John Corra, Wyoming Department of Environmental Quality
Chuck Otto, BLM Pinedale Field Office Manager

Enclosures

Detailed Comments by the Region 8 Environmental Protection Agency for the Draft Supplemental Environmental Impact Statement (SEIS) Pinedale Anticline Oil and Gas Exploration and Development Project Sublette County, Wyoming

Air Quality – Visibility

The Clean Air Act requires special protection of air quality and air quality related values (such as visibility) in many of the nation's wilderness areas and national parks. Subpart II of Part C of the Clean Air Act prescribes a program specifically for the protection of visibility in federal Class I areas and establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I federal areas which impairment results from man-made air pollution." EPA's implementing regulations require states to submit implementation plans that contain such measures as are necessary to make reasonable progress towards the national requirements, and that states establish reasonable progress goals toward improving visibility on the worst days and preventing further degradation in visibility during the best days. Actions by BLM that lack adequate mitigation of potential visibility impacts could impede Wyoming's and neighboring states' ability to submit State Implementation Plans that meet the Clean Air Act requirements.

In addition to its visibility provisions, the Clean Air Act contains general provisions for a Prevention of Significant Deterioration (PSD) program designed to protect federal Class I areas from air quality degradation under Subpart I of Part C. The PSD program places an affirmative responsibility on federal land managers to protect air quality in many of the most important national parks and wilderness areas in the nation from human-caused pollution. The Wilderness Act further directs the federal land management agencies to protect the wilderness character of those areas designated as wilderness. In that Act, Congress recognized the importance of preserving designated areas in their natural condition and declared a policy to "secure for the American people of present and future generations the benefits of an enduring resource of wilderness."

As stated on page 4-74 of the Revised Draft SEIS, "BLM considers a 1.0 deciview (dv) change to be a significance threshold for visibility impairment," which is consistent with other federal agencies' approach to visibility protection. Pursuant to the Clean Air Act and other provisions of law, EPA and the Federal Land Managers have developed regulations, guidance, and technical tools including models and data that land managers can use to help protect air quality in federal Class I areas. One of these is a guidance document from the Federal Land Managers' Air Quality Related Values Workgroup (FLAG), a workgroup that the federal land managers formed to develop a more consistent approach to evaluate air pollution effects on the areas that they manage. The FLAG guidance document states that impacts greater than 1.0 dv would be considered perceptible and significant for new source review purposes, and EPA supports efforts by the Federal Land Managers to coordinate and streamline their participation in permitting. EPA has not adopted the 1.0 dv threshold into rules governing the requirements for federal or state New Source Review programs.

The Revised Draft SEIS includes analysis of modeled visibility impacts for both the current level of development in 2005 and the proposed project development through 2023. In Chapter 3.11, the Revised Draft SEIS discusses the visibility analysis conducted for 2005 and discloses the impacts of development that have occurred since BLM's 2000 Pinedale Anticline ROD. This analysis was conducted because the level of development since 2000 led to emissions that significantly exceeded those analyzed in the earlier EIS, triggering additional analysis under the 2000 Pinedale Anticline ROD. The visibility modeling analysis for the 2005 level of development predicts 45 days per year of visibility change greater than the 1.0 dv threshold at the Bridger Wilderness Area, five days per year at the Fitzpatrick Wilderness Area, and additional days at other regional Class I and sensitive Class II areas. Under the No Action scenario where development occurs under the provisions of the 2000 ROD, predicted 2007 visibility impacts are even higher with 62 days above 1.0 dv at Bridger Wilderness Area, 8 days at Fitzpatrick Wilderness Area and additional days at other regional Class I and sensitive Class II areas.

The BLM Preferred Alternative (Alternative D) proposes an air quality mitigation plan that attempts to reduce visibility impacts to Federal Class I areas from both the existing development and the proposed development. Detailed in Section 4.9.3.5 of the Revised Draft SEIS, the air quality mitigation plan provides for a two-phased approach to minimizing visibility impacts. Phase I mitigation would initiate after issuance of the ROD and would require operators to reduce project induced visibility impairment to 2005 levels. Immediately following Phase I, Phase II would require operators to reduce drill rig emissions by 80 percent over four years. The intervening years (years two through five) would have stepped 20 percent decreases in NO_x emissions with corresponding decreases in the number of days of impairment in the Class I areas. The ultimate goal of Phase II mitigation is zero days of visibility impairment at Bridger Wilderness Area. However, after the five-year period and the 80 percent reduction in NO_x emissions from drilling rigs, the Bridger Wilderness area is projected to have at least 10 days of impairment (greater than 1.0 dv) with impairment at other nearby Class I areas as well. During the first five years the proposed project will not meet the intent of Section 169A of the Clean Air Act (CAA) Amendments of 1977, which requires the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from man-made air pollution."

EPA fully supports the ultimate goal of Phase II air quality mitigation: zero days of visibility impairment over 1.0 dv at the Bridger Wilderness Area. However, EPA is concerned that the commitment to achieve the goal has been weakened with the significant modifications of the original commitments. Specifically, EPA is concerned that the addition of "practicable" in the commitment for "using any and all practicable means with full consideration of all resources" and the addition of "technically and economically practicable" create uncertainty and doubt that the ultimate goal will be achieved. The modified commitments suggest reluctance to commit to the full mitigation plan and have eroded EPA's confidence that the goal of zero days will be achieved. Without further specificity on how the ultimate goal will be achieved, EPA believes the proposed project will result in at least ten days of visibility impairment at the federal class I Bridger Wilderness Area. EPA considers ten days of visibility impairment greater than 1.0 dv a significant, adverse impact to air quality. EPA recommends BLM strengthen the language and include more specific details in the air quality mitigation plan to ensure the goal of zero days of impairment is met within a scheduled timeframe. Specifically, EPA recommends that the Revised SEIS include the air quality mitigation commitments set forth in the December 2006 Draft SEIS that if modeling cannot demonstrate achievement of this goal within five years of the ROD being signed, the Operators, BLM, EPA, and WDEQ would jointly agree to a mitigation plan that complies with the goal of zero days, using any and all available means.

Air Quality – Ozone Analysis

EPA commends BLM for updating the Ozone (O_3) analysis using the photochemical grid model, CAMx. The Revised Draft SEIS discloses summary results from air modeling conducted for the proposed Pinedale Anticline project and other cumulative emission sources. The maximum predicted ozone impacts using the EPA guidance approach occur near the PAPA. For Alternative C (Alternative C is similar to BLM's Preferred Alternative) with the 80 percent reduction in drill rig emissions, ozone concentrations are predicted to be 0.0765 ppm near the PAPA. The Revised Draft SEIS does not provide analysis of ozone concentrations for the first five years prior to full implementation of the 80 percent reduction in drill rig emissions under the air quality mitigation strategy. The performance evaluation of the photochemical model supported the model's reliability in predicting ozone but also noted a small underestimation bias. With predicted ozone concentrations approaching the current standard and an underestimation bias in the model, EPA is concerned with the health impacts associated with the projected 0.0782 and 0.0765 ppm ozone concentrations with this proposed project. This concern is further substantiated by the elevated ozone concentrations above the current 0.08 ppm ozone standard recorded at Sublette County ambient air monitoring stations in 2005 and 2006.

In view of the ozone levels monitored, modeled and predicted, EPA recommends that an air quality mitigation strategy be developed to address not only NO_x sources, but include measures to control other O_3 forming precursors such as volatile organic compounds (VOCs) and formaldehyde. The SEIS should also include modeled demonstrations that the proposed action will not incrementally contribute to violations of a NAAQS. In addition, EPA is currently reviewing the national primary and secondary standards for ozone. This project may be affected if EPA determines that a revision to the current ozone standard is necessary and appropriate. Consequently, EPA may have further comments on the project's ozone analysis after the final rule is issued.

Detailed Ozone Comments

1. The design value predictions for the reported modeling for Alternative C (Alternative C is similar to BLM's Preferred Alternative) were based on an 80 percent NO_x reduction in the PAPA after four years with intervening years of 20 percent stepped decreases in NO_x emissions. For the intervening years, predicted O_3 design value concentrations have not been reported. These values may be considerably higher and EPA recommends they be reported in the SEIS.

2. Figure 4-4 of Appendix H of the Air Quality Impact Analysis Technical Support Document for the Revised Draft SEIS upper right map depiction for Alternative C (Alternative C is similar to Alternative D, BLM's Preferred Alternative) presents the predicted difference in O_3 design value impacts from Alternative C with Phase II mitigation to the base case scenarios. Please clarify the location of the maximum impact location from this figure. Furthermore, the difference of 5.5 ppb presented in Figure 4-4 is not represented in Table 4-1 of Appendix H. EPA recommends the maximum predicted O_3 concentration near the PAPA and approximate location of these impacts be presented in the SEIS.

3. Ozone concentrations were predicted for cumulative sources in the PAPA and surrounding areas. EPA recommends the SEIS disclose ozone concentrations for PAPA specific sources in order to determine the direct project impacts. In addition, EPA recommends the analysis disclose the absolute modeled results in addition to the results calculated under EPA's guidance approach.

4. Section 5.2.2.1. EPA Guidance Ozone - Projection Approach EPA guidance for projecting future ozone concentrations using relative reduction factors to scale current observed ozone design values is required for State Implementation Plan (SIP) modeling in urban non-attainment areas. The approach is useful in the context of the current study; however, the ozone monitoring network is very sparse compared to urban monitoring networks. For this reason EPA recommends the absolute model prediction of maximum ozone concentrations be presented in addition to the "scaled" modeled attainment test (MATS) results used in SIP modeling.

Groundwater

The Revised Draft SEIS includes significant new information on groundwater monitoring that was completed under a monitoring program established under the 2000 Pinedale Anticline ROD. The monitoring data suggest that current drilling and production activities on the PAPA have contributed to contamination of an aquifer used as a drinking water source. Benzene and other hydrocarbons have been detected in 88 of the approximately 230 water supply wells monitored or 38 percent of the wells tested. Existing benzene contamination exceeding the Drinking Water Standard (maximum concentration level or MCL) in two wells was attributed to oil and gas exploration activities in the Revised Draft SEIS. The Revised Draft SEIS does not disclose the monitored concentrations; it is, therefore, unknown how much the monitored concentrations are above or below the MCL. Based upon the extent of contamination of these two wells completed in an aquifer used as a source of drinking water and benzene contamination in approximately one third of the other wells monitored, EPA is concerned about the significance of existing and potential future impacts associated with activities in the PAPA. EPA believes that such impacts are environmentally unsatisfactory.

While the monitoring data suggest significant impacts to groundwater have occurred in the PAPA, insufficient information has been provided to fully understand the nature of the existing contamination and the potential for additional groundwater contamination from the proposed action. Although the 2000 Pinedale ROD required that all wells within one mile of proposed development be monitored on an annual basis, there is no documentation of how many wells are within this defined buffer area nor is it documented that monitoring took place in the defined areas. The Wyoming State Engineer has identified 4000 points of use within the PAPA. While some of these points of use may be duplicates, monitoring has taken place in only approximately 230 wells. The full extent of the benzene and hydrocarbon contamination in the PAPA has not been comprehensively evaluated. In addition, although there are five distinct aquifers in this area described in the Revised Draft SEIS, information on impacts and potential mitigation measures were generalized across all of the aquifers.

The Revised Draft SEIS provides mitigation measures intended to reduce impacts to groundwater. These measures, however, were only identified as potential requirements and were not evaluated as to their effectiveness in any of the alternatives. As the source of the widespread low concentration detections remains unclear, it is difficult to identify and implement effective mitigation measures to protect valued groundwater supplies without understanding of the source of contamination. EPA recommends that where impacts have occurred or may reasonably be expected to occur to groundwater sources as a result of oil and gas production, including but not limited to hydraulic fracturing practices, an effective and enforceable mitigation plan should be developed. The mitigation plan could specifically include plans for replacement of quality water to water users if necessary.

Based on the information included in the Revised Draft SEIS, EPA recommends BLM develop a monitoring plan sufficient to characterize each of the aquifers throughout the PAPA. Use of industrial water wells, not designed for monitoring purposes, provides inadequate information to identify and mitigate groundwater problems. We suggest that monitoring methods approved by the Wyoming DEQ be used to ensure Quality Control over the monitoring process, including proper drilling methods and casing. Furthermore, each new well within the PAPA should be logged and sampled during drilling preventing any cross-contamination with industrial uses. EPA also suggests the Revised SEIS include a map identifying the approximately 230 wells that have been tested; the wells with detectable levels of benzene and other hydrocarbons; and the wells with benzene concentrations above the MCL.

EPA believes it is important to sustain and protect quality drinking water supplies in times of increased demand for water and especially in times of drought. Rather than using potable grade water for drilling, EPA recommends BLM consider and evaluate non-potable alternative drilling water sources in the Revised SEIS. The Fort Union Formation at a slightly deeper depth is an aquifer with adequate quality for industrial purposes but is not of high enough quality for a water supply at this time. In addition, reuse of produced water is also demonstrated within the PAPA and could potentially be an appropriate alternative for industrial water supply.

Finally, EPA recommends the Revised SEIS include a more detailed analysis of cumulative groundwater impacts. EPA is aware of additional groundwater contamination that has occurred in the Jonah field directly south and adjacent of the Pinedale Anticline. The drilling water well in the Jonah field has monitored levels of benzene of 615 ug/l at a depth of over 900 feet with lower concentrations near surface. This information should be disclosed to the public in addition to any other existing monitoring analyses for the area.

No Action Alternative

As previously mentioned in EPA's April 6, 2007, comments on the Draft SEIS, NEPA requires analysis of a No Action Alternative in order to establish an environmental impacts baseline for comparison with the Proposed Action. In the December 2006 Draft SEIS and in this Revised Draft SEIS, BLM analyzes the No Action Alternative in terms of continuing with the present course of action until that action is changed (i.e., approving wells under the 2000 ROD until approval of a new ROD). The Revised Draft SEIS states there is "uncertainty" with regard to the 2000 ROD. Any uncertainty should be resolved by examining the extent of development actually analyzed in the Pinedale Anticline Oil and Gas Exploration and Development Project EIS, that is, impacts associated with the development of 700 producing natural gas wells over a 10 to 15 year time period. EPA believes that this scenario should be the basis for the No Action Alternative rather than the No Action Alternative considered in the Revised Draft SEIS which includes the development of an additional 1,139 wells for a total of approximately 1,800 wells by the year 2011. EPA recommends the No Action Alternative and baseline analysis be revised to accurately reflect the 700 producing well scenario analyzed in the initial Pinedale Anticline EIS and implemented in the 2000 ROD.

Surface Water, Water Quality, and Aquatic Habitat

In the Revised Draft SEIS's executive summary, it is acknowledged that sediment yields will be substantially increased above current conditions in six hydrologic sub-watersheds that coincide with the Anticline Crest. This conclusion is substantiated by the *Erosion Modeling, Sediment Transport Modeling and Salt Loading Technical Report* prepared by HydroGEO which was presented in Table 4.14-4 in the previous Draft SEIS (December 2006). This important finding and the table illustrating the diverse and varied effects in different subwatersheds should be re-inserted in the Revised Draft SEIS. This information provides insight and geographic pattern to a potentially significant environmental effect, and EPA recommends that this Table and a discussion of its findings should be a part of this analysis. According to the model, the average annual sediment yield would increase by 73% in the New Fork River – Alkali Creek, 102% in Mack Reservoir and 26% in the Sand Draw-Alkali Creek sub-watersheds in 2023 (under the worst case modeling scenario with no reclamation). Yet, Chapter 4.14 concludes these substantial increases in sediment yield are not expected to result in "significant" impact to surface water resources under any of the alternatives. It appears this conclusion is reached based on a finding that the increased sediment loading, although substantial, would not impair the designated uses for these waters. The Revised Draft SEIS does not clearly explain the basis for this conclusion. EPA strongly recommends that the Revised SEIS clarify how the projected increased sediment yields are translated into projected compliance with Wyoming's narrative water quality standard for settleable solids, which states:

> "In all Wyoming surface waters, substances attributable to or influenced by the activities of man that will settle to form sludge, bank or bottom deposits shall not be present in quantities which could result in significant aesthetic degradation, significant degradation of habitat for aquatic life or adversely affect public waters supplies, agricultural or industrial water use, plant life or wildlife."

It is also clear from the Revised Draft SEIS that avoiding adverse effects to the designated uses will rely on "extensive" use of Best Management Practices (BMPs) to prevent erosion, as well as timely reclamation. To ensure adverse effects to surface water quality are avoided, EPA recommends the Revised SEIS identify: 1) the target and the threshold of change (e.g., percent change of fines, or in suspended sediment) from the target being used to determine compliance with the designated uses assigned to these waters; and 2) the level of effectiveness for the applicable BMPs; 3) the process that will be used to ensure effective implementation and maintenance of those BMPs (i.e., ongoing and future monitoring of effectiveness and implementation enforcement); 4) and how sufficient reclamation will be accomplished and monitored given the ambient ecological conditions.

The Revised Draft SEIS notes that a number of waters within the Anticline Crest are prime sport fisheries. Measures of impact to these aquatic communities from increased sediment yield could be based on either change in biological condition or change in bedded sediments (% fines). The Revised Draft SEIS notes that a report by EcoAnalysts, Inc. (2005) concluded "... there has been no discernable change in ... invertebrate biology indices between 2000 and 2005." EPA recommends the Revised SEIS provide more detail about this analysis as well as the general approach to and results of the monitoring conducted by the Sublette County Conservation District (SCCD). For example, is the biological monitoring approach used similar to, or consistent with, the Wyoming DEQ's bioassessment protocol? [see: Wyoming DEQ's *Redevelopment of the Wyoming Stream Integrity Index (WSII) for Assessing the Biological Condition of Wadeable Streams in Wyoming*]. At a minimum, EPA recommends the discussion include information about the biological metrics or index used, the basis for their derivation and application, and level of precision by which these analyses are able to define thresholds that would avoid "significant degradation of habitat for aquatic life" under Wyoming's narrative standard.

Once a target and threshold of change from the target have been identified, EPA recommends BLM implement a comprehensive water monitoring plan to ensure the BMPs are successfully mitigating the impacts from increased sedimentation and that the identified target is being met. At a minimum, we recommend that BLM establish a monitoring program in the most sensitive watersheds and the watersheds most likely to be impacted. EPA is concerned that such monitoring is not already ongoing, and looks forward to BLM establishing an effective monitoring program and utilizing the results from those monitoring efforts to direct reclamation resources and efforts.

It is best to involve a system of BMPs that targets each stage of the erosion process to ensure success from construction activities. The most efficient approach involves minimizing the potential sources of sediment from the outset. This means limiting the extent and duration of land disturbance to the minimum needed, and protecting surfaces once they are exposed. BMPs should also involve controlling the amount of runoff and its ability to carry sediment by diverting incoming flows and impeding internally generated flows. And finally, BMPs should involve retaining sediment that is picked up on the project site through the use of sediment-capturing devices. On most sites successful erosion and sedimentation control requires a combination of structural and vegetative practices. Above all BMPs are best performed using advance planning, good scheduling and maintenance.

In the 2000 Pinedale Anticline ROD, BLM committed to implementing a monitoring program to ensure that the Green and New Fork Rivers continue to support their designated uses. Yet, the Draft SEIS indicates that it is not known if significant impact has occurred to surface water. EPA recommends BLM include a discussion of the surface monitoring program, any obstacles in implementing the program, and any monitored results in the Revised SEIS. Further, the Revised SEIS should analyze the potential for underground aquifer interaction with surface water and the potential resulting impacts should the benzene and hydrocarbon contamination reach these high value prime fisheries.

Wetlands

As noted in the Revised Draft SEIS, certain wetlands are subject to protection pursuant to the Clean Water Act and Executive Order 11990. The Clean Water Act (CWA) Section 404 regulates discharge of dredged or fill material into "waters of the United States," including jurisdictional wetlands. Under CWA Section 404, permits for such discharges are generally issued by the U.S. Army Corps of Engineers, in accordance with EPA's CWA Section 404(b)(1) guidelines. These guidelines require, among other provisions, that no discharge of dredged or fill material shall be permitted unless appropriate and practicable steps have been taken which will minimize potential adverse impacts of the discharge on the aquatic ecosystem (40 CFR 230.10(d). In addition, Executive Order 11990 – Protection of Wetlands (May 24, 1977) states in pertinent part as follows: "Section 1. (a) Each agency shall provide leadership and shall take action to minimize the destruction, loss or degradation of wetlands, and to preserve and enhance the natural and beneficial values of wetlands in carrying out the agency's responsibilities for (1) acquiring, managing, and disposing of Federal lands and facilities; and (2) providing Federally undertaken, financed, or assisted construction and improvements; and (3) conducting Federal activities and programs affecting land use, including but not limited to water and related land resources planning, regulating, and licensing activities. (b) This Order does not apply to the issuance by Federal agencies of permits, licenses, or allocations to private parties for activities involving wetlands on non-Federal property." It should be noted that Executive Order 11990 is not limited to wetlands regulated under the Clean Water Act.

EPA considers the protection, improvement, and restoration of wetlands and riparian areas to be a high priority. Executive Order 11990 directs all Federal Agencies to provide leadership and take action to minimize the destruction, loss or degradation of wetlands, and to preserve and enhance the natural and beneficial values of wetlands. EPA recommends that, consistent with the Executive Order, indirect draining of, or direct disturbance of, wetland areas should be avoided if at all possible. If disturbance is unavoidable, BLM should commit to replace in kind such impacted wetlands and to a level that fully restores wetland function and value. Due to the time it can take to adequately reclaim disturbed wetlands and the potential life of this project, BLM may consider requiring mitigation to begin concurrent with the disturbance.

The Revised Draft SEIS provides updated information on potential impacts to wetlands from the Proposed Action and Preferred Alternative. An additional 183.9 acres of disturbance in riparian forest and riparian shrub vegetation are predicted, yet no mitigation for wetland and riparian resources has been identified (page 4-129). EPA recommends that the Revised SEIS discuss BLM's approach to implementing federal wetland policies and legal requirements in the continued development of the PAPA. In particular, EPA recommends the Revised SEIS clearly explain how BLM will be mitigating the loss and disturbance of wetlands and streams within and adjacent to the PAPA under Executive Order 11990. EPA is available to provide guidance and work with BLM towards development of a mitigation plan for the Revised SEIS and development of an implementation plan.

Greenhouse Gas Emissions

EPA believes the greenhouse gases section in the Final SEIS should be expanded, keeping in mind that there are currently no EPA regulatory standards directly limiting greenhouse gas emissions[1]. While methane represents only 8 percent of the U.S. greenhouse gas emissions, it is 23 times more effective as a greenhouse gas than carbon dioxide. Oil and natural gas systems are the biggest contributor to methane emissions in the U.S., accounting for 26 percent of the total (EPA's Natural Gas Star Program and the US Emissions Inventory 2007: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005). EPA recommends that to the extent possible the Revised SEIS estimate and disclose the amount of methane and carbon dioxide emissions associated with each alternative in carbon dioxide-equivalent terms. As a point of comparison, EPA recommends the Revised SEIS consider utilizing a greenhouse gas equivalencies calculator to translate greenhouse gas emissions into terms that are easier to conceptualize. For example, a comparison of emissions to a range of other greenhouse gas

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[1] Since issuance of the April 2, 2007 Supreme Court opinion in Massachusetts, et. al. v. EPA, 127 S. Ct. 1438, 549 U.S. __ (2007), EPA has begun to develop regulations to address greenhouse gas emissions from motor vehicles and fuels under the direction of the President's May 14, 2007 Executive Order and relevant Clean Air Act authorities. The Agency continues to evaluate the potential effects of the Court's decision with respect to addressing emissions of greenhouse gases under other provisions of the Clean Air Act. Thus, neither this comment letter nor the EIS for an individual project reflects, and should not be construed as reflecting, the type of judgment that might form the basis for a positive or negative finding under any provision of the Clean Air Act.

emitting sectors (www.epa.gov/solar/energy-resources/calculator.html).

As part of a cumulative impact analysis, in the event the GHG emissions associated with the project are significant, EPA recommends the Revised SEIS compare annual projected greenhouse gas emissions from the proposed project to annual emissions from other existing and reasonably foreseeable future projects. In addition, we recommend that the Revised SEIS compare the annual greenhouse gas emissions from the proposed project to estimated annual greenhouse gas emissions at a regional, national, and global scale. Emissions of greenhouse gases in the United States have been quantified by the U.S. Department of Energy and EPA in publications released in 2007. EPA recommends that the cumulative impacts analysis also include a general, qualitative discussion of the anticipated effects of climate change, including potential effects at a regional level.

The Revised SEIS should also identify possible mitigation measures that may be implemented to reduce and capture methane gas and reduce potential impacts. There are a number of voluntary, cost-effective technologies and practices to reduce and off-set greenhouse gas emissions. Through EPA's Natural Gas STAR (www.epa.gov/gasstar), EPA works with companies that produce, process, transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potent greenhouse gas.

Accountability for Implementation of Effective Mitigation Measures

The Revised Draft SEIS discloses the significant and unanticipated impacts to groundwater, air quality and wildlife that have occurred since implementation of the 2000 Pinedale Anticline ROD. Of particular concern:

- Benzene and other hydrocarbons have been detected in 88 of approximately 230 water supply wells sampled since monitoring began in 2004 (Revised Draft SEIS, page 3-84).

- Elevated ozone concentrations above the current National Ambient Air Quality Standard (NAAQS) have been recorded at Sublette County ambient air monitoring stations in 2005 and 2006 (Revised Draft SEIS, Table 3.11-2) and ground-level ozone concentrations have also increased.

- For 2005 "actual" emissions, a modeled 45 days of visibility impairment greater than 1.0 dv has occurred at the Class I Bridger Wilderness Area, 5 days at the Class I Fitzpatrick Wilderness Area, and additional days at other regional Class I areas (Revised Draft SEIS, page 3-73). For 2007, the predicted impacts to visibility are even higher with 62 days of visibility impairment predicted for the Bridger Wilderness Area (Revised Draft SEIS, page 4-78).

- Sage grouse male counts have declined by 51 percent on leks near the PAPA that were heavily impacted by gas wells from one year prior to well development in 1999 through 2004 (Revised Draft SEIS, page 3-135, Holloran, 2005).

Given the unforeseen and significant impacts that have occurred from the development of the 642 producing oil and gas wells approved under the 2000 Pinedale Anticline ROD, EPA believes that it is of the utmost importance that the Revised Draft SEIS identify effective and enforceable mitigation strategies to ensure environmental and public health protection as the proposed 4,399 additional wells on the Pinedale Anticline are developed. The Revised Draft SEIS should also develop a plan to mitigate the significant environmental impacts resulting from the oil and gas development that has already occurred on the PAPA. While the Revised Draft SEIS includes many of the necessary components that provide a starting point for mitigation, EPA recommends each of the mitigation plans include a mechanism for public accountability, such as stakeholder forums and/or annual status reports. Public accountability can be an important tool in ensuring mitigation targets are met in a timely manner.

Exhibit 13

COM, *Update of Task 3A Report for the Powder River Basin Coal Review Cumulative Air Quality Effects for 2020*, Prepared for Bureau of Land Management, High Plains District Office, Wyoming State Office, and Miles City Field Office (Dec. 2009)

Update of Task 3A Report for the Powder River Basin Coal Review Cumulative Air Quality Effects for 2020

Prepared for

Bureau of Land Management
High Plains District Office,
Wyoming State Office, and
Miles City Field Office

Submitted by

AECOM, Inc.
Fort Collins, Colorado

December 2009

UPDATE OF TASK 3A REPORT FOR THE POWDER RIVER BASIN COAL REVIEW CUMULATIVE AIR QUALITY EFFECTS FOR 2020

Prepared for

BUREAU OF LAND MANAGEMENT
HIGH PLAINS DISTRICT OFFICE,
WYOMING STATE OFFICE, AND
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ES.1 INTRODUCTION

The Powder River Basin (PRB) of Wyoming and Montana is a major coal-producing region in the United States (U.S.). It also has produced large quantities of natural gas and oil, and has experienced significant development of coal bed natural gas (CBNG) from its coal seams. The region has a diverse set of environmental values, including proximity to some of the most pristine areas in the U.S.

This update to the Task 3A Report for the PRB Coal Review evaluates the air quality-related environmental impacts of ongoing development in the region. The Task 1A Report for the PRB Coal Review, Current Air Quality Conditions (ENSR 2005a) documented the air quality impacts of operations during a base year (2002), using actual emissions and operations for that year. The base year analysis evaluated impacts both within the PRB itself and at selected sensitive areas surrounding the region. The analysis specifically quantified impacts of coal mines, power plants, CBNG development, and other activities. Results were provided for both Wyoming and Montana source groups and receptors.

The Task 2 Report for the PRB Coal Review, Past and Present and Reasonably Foreseeable Development Activities (ENSR 2005b) depicted the range of projected coal-related development in the PRB, for selected source groups. The report identified reasonably foreseeable development (RFD) activities for the years 2010, 2015, and 2020, and was separated into selected, partially overlapping source groups, including power plants, coal mine development, conventional oil and gas and CBNG activities, and other coal-related energy development scenarios. The results of that study were used to develop changes in air pollution emission rates for source groups in 2010, 2015, and 2020 which are the basis for modeled estimates of the projected cumulative air quality impacts. The 2020 RFD scenarios from the Task 2 report were updated with current information, as applicable, and revised emissions were included in this updated analysis.

The original Task 3A report (ENSR 2006) provided a modeled change in impacts on air quality and air quality-related values (AQRVs) resulting from the projected RFD activities in 2010. Impacts of coal and other resource development were evaluated for each source group and for the various receptor groups. The Task 2 projected development for 2010 was modeled using the same model and meteorological data that were used for the base year study in the Task 1A report. Impacts for 2015 and 2020 were qualitatively projected based on modeled impacts for 2010 and expected changes in source group emissions identified in the Task 2 study. As the uncertainty associated with predicted developments for 2015 and 2020 decreased, it became increasingly valuable to update the original Task 3A qualitative estimates for 2015 and 2020 with a quantitative evaluation. In 2008, the cumulative air quality effects for 2015 were modeled, and the Task 3A study correspondingly was updated (ENSR 2008a).

This current update to the Task 3A report quantitatively updates the original Task 3A qualitative analysis based on modeled changes in impacts on air quality and AQRVs resulting from the projected RFD activities in 2020. Similar to the original Task 3A report, impacts due to development of selected source types were evaluated at various receptor locations. Several important changes that occurred during the development of the 2015 update were carried through to this 2020 update. The changes that affect the comparison of this updated report with the original Task 3A report include:

- A new version of the dispersion model used to predict air quality and AQRVs;
- Initiation of the dispersion model with a different meteorological year;
- An improved base year emissions inventory; and
- Updated RFD emission sources and projected emissions activities to 2020.

ES.2 TECHNICAL APPROACH

Similar to the original Task 3A report, this updated analysis evaluates two levels of coal development: a lower production (or development) scenario and an upper production scenario. Existing and projected sources in the study area were analyzed using base year emissions and adjusting those emissions based on the projected development level. Emissions were evaluated for sources in the study area, which comprises several counties in the PRB in both states:

- Wyoming portion of the study area comprises all of Campbell County, all of Sheridan and Johnson counties except the Bighorn National Forest lands to the west of the PRB, and the northern portion of Converse County
- Montana portion of the study area comprises the area of relevant coal mines including portions of Rosebud, Custer, Powder River, Big Horn, and Treasure counties

The study evaluates impacts on air quality and AQRVs resulting from projected development of RFD activities (for 2020) in the study area. For the original Task 3A study, a quantitative modeling assessment was used to predict ambient air quality impacts for 2010, and qualitative evaluations were made for 2015 and 2020. For this current update to the Task 3A study, the original 2020 qualitative evaluations were quantitatively updated based on the same approach previously used to predict ambient air quality impacts for 2010 and 2015.

A state-of-the-art, guideline dispersion model was used to evaluate impacts at several locations:

- Near-field receptors in Wyoming (within the PRB study area);
- Near-field receptors in Montana (within the PRB study area);
- Receptors in nearby federally designated pristine or Class I areas; and
- Receptors at other sensitive areas (sensitive Class II areas).

The U.S. Environmental Protection Agency (USEPA) guideline CALPUFF model system version 5.8 (Scire et al. 2000a,b) was used for this study, which differs from the version used in the Task 1A and original Task 3A studies. The modeling domain is identical to the Task 1A, original Task 3A, and 2015 update to the Task 3A studies and extends over most of Wyoming, southeastern Montana, southwestern North Dakota, western South Dakota, and western Nebraska. A group of agency stakeholders participated in developing the modeling protocol and related methodology that were used for this analysis (ENSR 2008b).

This updated Task 3A report uses an identical model setup, meteorological input data, and base year emissions inventory as the 2015 update. Previously, the base year inventory was developed for actual emissions in 2002; for this update, the base year emissions inventory is for year 2004. Detailed information regarding the development of the emissions information is available in the 2015 update report (ENSR 2008a) and its corresponding Technical Support Document (ENSR 2008d). The base year emissions inventory is projected into future year 2020 for upper and lower production scenarios.

The meteorological data set for 2003 was selected as the worst-case meteorological year during the 2015 update based on an analysis of visibility impacts at the nearest Class I areas. The meteorological year 2003 was then used to model impacts for all emissions sources for the revised base year and the 2015 and 2020 development scenarios. Modeling data settings generally were set to default values. Base year ozone concentrations also were incorporated into the model using measured concentrations representative of the study area.

The objective of this updated study is to provide a quantitative evaluation of projected 2020 cumulative air quality impacts for comparison to both the base year impacts and the 2020 qualitative projections from the original Task 3A report. For this updated study, the base year (2004) and projected future year (2020) impacts are evaluated using the same receptor set and modeling domain used for the Task 1A and original Task 3A reports. The 2020 development scenarios were directly modeled for this study. The only difference between the base year and future year predicted impacts is due to the projected change in emissions as a result of RFD activities in the PRB study area. This report documents the modeled impacts for 2020 under both the upper and lower development scenarios. The changes in air quality and AQRVs due to projected development in the PRB are summarized and compared with the original Task 3A qualitative projections for 2020.

ES.3 CUMULATIVE IMPACTS

Generally, measured air quality conditions are good throughout the region. The base year (2004) modeling showed that there is reason for concern regarding the short-term impacts for some pollutants including particulate matter (PM) with an aerodynamic diameter of 10 microns or less (PM_{10}) and PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). The base year modeling also predicted substantial visibility impacts at the nearby Class I and sensitive Class II areas. For regulatory purposes, the Class I evaluations are not directly comparable to the air quality permitting requirements, because the modeling effort does not segregate increment-consuming sources that would need to be evaluated under the Prevention of Significant Deterioration (PSD) program. The cumulative impact analysis focuses on changes in cumulative impacts versus a comparison to PSD-related evaluations, which would apply to specific sources. Changes in predicted impacts for air quality parameters (NO_2, sulfur dioxide [SO_2], PM_{10}, and $PM_{2.5}$) were evaluated, along with changes in AQRVs at Class I and sensitive Class II areas.

It is important to note that the effects of Best Available Retrofit Technology (BART) implementation are not incorporated into the results presented below, since the states are still developing their implementation plan. It is anticipated that air quality effects from large sources summarized below likely would be reduced as a result of BART regulations.

Table ES-1 presents the modeled impacts on ambient air quality at the near-field receptors in Montana and Wyoming. Results indicate the maximum impacts at any point in each receptor group. Results are summarized for both 2020 development scenarios, and results from the base year are included for comparison purposes. Peak impacts occur at isolated receptors and are likely due to unique source-receptor relationships. The model results should not be construed as predicting an actual exceedence of any standard, but are at best indicators of potential impacts.

The results of the modeling depict the anticipated changes under both development scenarios. For the Wyoming near-field receptors, the predicted impact of the 24-hour PM_{10} and $PM_{2.5}$ concentrations show localized exceedences of the National Ambient Air Quality Standard (NAAQS) for the base year (2004), as well as for both development scenarios for 2020. The 2020 development scenarios show the concentration increases by a factor of 2.5 relative to the base year for these parameters. Additionally, 2020 development scenarios show a 20 percent increase of annual PM_{10} and $PM_{2.5}$ concentrations at peak Wyoming near-field receptors. This level of increase indicated modeled exceedences of annual standards for $PM_{2.5}$.[1] Impacts of NO_2 and SO_2 emissions are predicted to be below the NAAQS and Wyoming State Ambient Air Quality Standard (SAAQS) at the Wyoming near-field receptors.

Based on the modeling results, impacts at Montana near-field receptors would be in compliance with the NAAQS and the Montana SAAQS for all pollutants and averaging periods. Importantly, the 1-hour NO_2 concentrations at Montana near-field receptors for 2015 were predicted to exceed the SAAQS at isolated locations due to CBNG development in Wyoming; however, with the anticipated southward progression of the CBNG wells, the 1-hour NO_2 concentrations in 2020 are predicted to remain below the SAAQS. The southward progression of the CBNG wells also contributes to a

[1] At the time of publication of this report, the annual PM_{10} NAAQS have been revoked by the USEPA. The state-specific annual PM_{10} standards are still in effect. Modeled impacts are compared to the annual PM_{10} threshold for consistency with the original Task 3A Report.

predicted decrease in impacts for annual NO_2, PM_{10} and $PM_{2.5}$ relative to the base year. Although large percentage increases were predicted in SO_2 impacts, the levels would be below the ambient standards for all pollutants in the Montana near-field.

Table ES-1
Projected Maximum Potential Near-field Impacts
(μg/m³)

Pollutant	Averaging Time	Base Year (2004) Impacts	2020 Lower Development Scenario Impacts	2020 Upper Development Scenario Impacts	NAAQS	Wyoming SAAQS	Montana SAAQS	PSD Class II Increments
Wyoming Near-field								
NO_2	Annual	31.3	80.5	80.6	100	100	--	25
SO_2	Annual	15.3	16.4	16.5	80	60	--	20
	24-hour	112.3	144.3	144.3	365	260		91
	3-hour	462.0	936.7	936.7	1,300	1,300	--	512
$PM_{2.5}$	Annual	13.4	**16.3**	**16.3**	15	15	--	--
	24-hour	**87.6**	**218.4**	**218.5**	35	35	--	--
PM_{10}	Annual	38.4	46.6	46.6	--	50	--	17
	24-hour	**250.4**	**624.1**	**624.3**	150	150	--	30
Montana Near-field								
NO_2	Annual	3.3	2.5	2.6	100	--	100	25
	1-hour	409.0	440.1	442.7	--	--	564	--
SO_2	Annual	1.6	3.0	3.1	80	--	80	20
	24-hour	16.1	24.7	27.1	365	--	365	91
	3-hour	65.0	138.9	138.9	1,300	--	1,300	512
	1-hour	162.9	237.0	259.1	--	--	1,300	--
$PM_{2.5}$	Annual	1.0	0.9	0.9	15	--	15	--
	24-hour	10.2	10.2	10.2	35	--	35	--
PM_{10}	Annual	2.8	2.5	2.6	--	--	50	17
	24-hour	29.1	29.3	29.3	150	--	150	30

Note: -- = No standard or increment.
μg/m³ = microgram per cubic meter.
Bold numbers indicate potential exceedences.

Table ES-2 provides modeled impacts at the three Class I areas and two Class II areas with the greatest impacts. A comparison to SAAQS and PSD increments is provided; however, the analysis did not separate PSD increment-consuming sources from those that did not consume increment. The PSD-increment comparison is provided for informational purposes only and cannot be directly related to a regulatory interpretation of PSD increment consumption.

None of the modeled Class I areas currently have, or are predicted to have, NAAQS or SAAQS exceedences. **Table ES-2** compares the modeled impacts to the PSD Class I and sensitive Class II increment levels. At the Northern Cheyenne Indian Reservation (IR), Badlands National Park (NP) and Wind Cave NP base year impacts are slightly above the Class I comparative levels for 24-hour PM_{10} in 2020. Additionally, the SO_2 impacts at the Northern Cheyenne IR for the 3-hour and 24-hour averaging period exceed the Class I PSD increment levels. In the other Class I areas, only the modeled 24-hour SO_2 impacts at Theodore Roosevelt NP and Fort Peck IR, and 3-hour SO_2 impacts at Theodore Roosevelt NP, are above the PSD increment levels for the 2020 development scenarios; the predicted exceedences for these areas are due to sources outside the PRB study area.

Table ES-2
Maximum Predicted PSD Class I and Sensitive Class II Area Impacts
($\mu g/m^3$)

Location	Pollutant	Averaging Period	Base Year (2004) Impacts	2020 Lower Development Scenario	2020 Upper Development Scenario	PSD Class I and Class II Increments
Class I Areas						
Northern Cheyenne IR	NO_2	Annual	0.4	0.8	1.1	2.5
	SO_2	Annual	0.5	1.1	1.3	2
		24-hour	3.1	**7.1**	**12.8**	5
		3-hour	9.4	23.6	**39.7**	25
	$PM_{2.5}$	Annual	0.3	0.4	0.5	--
		24-hour	3.4	4.5	4.6	--
	PM_{10}	Annual	0.9	1.2	1.5	4
		24-hour	**9.6**	**12.9**	**13.2**	8
Badlands NP	NO_2	Annual	0.1	0.2	0.2	2.5
	SO_2	Annual	0.5	0.6	0.6	2
		24-hour	3.6	4.0	4.0	5
		3-hour	8.1	8.2	8.2	25
	$PM_{2.5}$	Annual	0.2	0.3	0.3	--
		24-hour	2.1	3.0	3.1	--
	PM_{10}	Annual	0.7	0.9	1.0	4
		24-hour	5.9	**8.5**	**8.8**	8
Wind Cave NP	NO_2	Annual	0.2	0.3	0.3	2.5
	SO_2	Annual	0.7	0.8	0.8	2
		24-hour	3.7	4.6	4.7	5
		3-hour	7.0	7.5	7.7	25
	$PM_{2.5}$	Annual	0.4	0.5	0.5	--
		24-hour	3.8	4.6	4.7	--
	PM_{10}	Annual	1.0	1.4	1.4	4
		24-hour	**10.9**	**13.0**	**13.3**	8
Sensitive Class II Areas						
Cloud Peak WA	NO_2	Annual	0.06	0.12	0.12	25
	SO_2	Annual	0.2	0.3	0.3	20
		24-hour	2.0	2.5	2.5	91
		3-hour	8.0	8.9	9.0	512
	$PM_{2.5}$	Annual	0.2	0.2	0.2	--
		24-hour	2.6	3.2	3.3	--
	PM_{10}	Annual	0.5	0.7	0.7	17
		24-hour	7.4	9.1	9.3	30
Crow IR	NO_2	Annual	0.9	3.6	4.2	25
	SO_2	Annual	2.3	2.4	2.4	20
		24-hour	14.4	14.8	14.8	91
		3-hour	76.8	77.0	77.0	512
	$PM_{2.5}$	Annual	0.8	0.8	0.8	--
		24-hour	7.2	7.2	7.2	--
	PM_{10}	Annual	2.2	2.3	2.4	17
		24-hour	20.5	20.6	20.6	30

Note: **Bold** numbers indicate potential exceedences.

In the sensitive Class II areas, there are no modeled exceedences of the Class II PSD Increments. The modeled annual NO_2 impacts at the Cloud Peak Wilderness Area (WA) and Crow IR are projected to increase by a factor of 2 to 4, respectively, in 2020 as a result of projected CBNG and coal hauling activities. For comparison purposes, modeling results for all sensitive Class II areas are below PSD increment levels for both 2020 development scenarios.

Table ES-3 provides a detailed listing of visibility impacts for all analyzed Class I and sensitive Class II areas. Modeled visibility impacts at the identified Class I areas continue to show a similar pattern as exhibited for the base year (2004), with a high number of days with a greater than 10 percent change in visibility at the most impacted Class I areas. Visibility impacts at Badlands NP, Northern Cheyenne IR, and Wind Cave NP all have greater than 10 percent change for more than 200 days a year during the base year. These Class I areas are the top three Class I areas with the highest predicted change in light extinction in 2020. All but four of the sensitive Class II areas have more than 100 days per year with greater than a 10 percent change during the base year. The most significant visibility change to sensitive Class II areas in 2020 is predicted for Black Elk WA and Mount Rushmore National Monument. Class II areas do not have any visibility protection under federal or state law.

Table ES-3
Modeled Change in Visibility Impacts at Class I and Sensitive Class II Areas

	Base Year (2004)	2020 Lower Development Scenario	2020 Upper Development Scenario
Location	**No. of Days >10%**	**Change in No. of Days > 10%**	**Change in No. of Days > 10%**
Class I Areas			
Badlands NP	218	44	44
Bob Marshall WA	8	0	0
Bridger WA	144	5	5
Fitzpatrick WA	91	6	6
Fort Peck IR	105	20	21
Gates of the Mountain WA	55	4	4
Grand Teton NP	70	6	6
North Absaorka WA	61	8	8
North Cheyenne IR	243	59	60
Red Rock Lakes	42	3	3
Scapegoat WA	27	2	2
Teton WA	57	8	8
Theodore Roosevelt NP	178	24	24
UL Bend WA	77	18	18
Washakie WA	83	8	8
Wind Cave NP	262	28	31
Yellowstone NP	84	5	5
Sensitive Class II Areas			
Absaorka Beartooth WA	101	10	10
Agate Fossil Beds National Monument	251	26	26
Big Horn Canyon NRA	331	1	1
Black Elk WA	236	47	47
Cloud Peak WA	126	29	30
Crow IR	360	3	3
Devils Tower National Monument	274	31	32
Fort Belknap IR	66	14	15
Fort Laramie National Historic Site	260	15	16
Jedediah Smith WA	79	3	3
Jewel Cave National Monument	261	36	37
Lee Metcalf WA	97	2	2
Mount Naomi WA	51	1	1
Mount Rushmore National Monument	222	49	52
Popo Agie WA	139	6	6
Soldier Creek WA	268	19	19
Wellsville Mountain WA	130	17	17
Wind River IR	217	9	10

For acid deposition, all predicted impacts are below the deposition threshold values for both nitrogen and sulfur compounds. There are substantial percentage increases in deposition under the lower and upper development scenarios; however, impacts remain well below the nitrogen and sulfur levels of concern (1.5 and 5.0 kilograms per hectare per year, respectively). The acid neutralizing capacity of sensitive lakes also was analyzed, and results are summarized in **Table ES-4**. The base year study indicated that none of the lakes had predicted significant impacts except Upper Frozen Lake; however, the lower and upper development scenarios for 2020 show an increased impact at Florence Lake, leading to an impact above the 10 percent change in acid neutralizing capacity (ANC). Impacts also are predicted to be above the 1 micro-equivalent per liter (μeq/L) for Upper Frozen Lake.

Table ES-4
Predicted Total Cumulative Change in Acid Neutralizing Capacity of Sensitive Lakes

Location	Lake	Background ANC (μeq/L)	Area (hectares)	Base Year (2004) Change (percent)	2020 Lower Development Scenario Change (percent)	2020 Upper Development Scenario Change (percent)	Thresholds (percent)
Bridger WA	Black Joe	67	890	4.00	4.26	4.27	10
	Deep	60	205	4.70	4.98	4.99	10
	Hobbs	70	293	3.95	4.14	4.15	10
	Upper Frozen	5	64.8	2.42	2.55	2.56	1[1]
Cloud Peak WA	Emerald	55.3	293	5.24	6.69	6.80	10
	Florence	32.7	417	9.09	11.79	11.99	10
Fitzpatrick WA	Ross	53.5	4,455	2.72	2.89	2.90	10
Popo Agie WA	Lower Saddlebag	55.5	155	6.28	6.65	6.67	10

[1]Data for Upper Frozen Lake presented in changes in μeq/L. (For lakes with less than 25 μeq/L background ANC.)

The study also modeled impacts of selected hazardous air pollutant emissions (benzene, ethyl benzene, formaldehyde, n-hexane, toluene, and xylene) on receptors with the highest ambient impacts. The near-field receptors in Wyoming and Montana were analyzed for annual (chronic) and 1-hour (acute) impacts. Model results for the base year (2004) and 2020 development scenarios show that impacts are predicted to be well below the acute Reference Exposure Levels, non-carcinogenic Reference Concentrations for Chronic Inhalation, and carcinogenic risk threshold for all hazardous air pollutants. The maximally exposed individual's carcinogenic risk factor due to benzene exposure is predicted to increase 50 percent as a result of projected development in the PRB; however, even with this substantial increase, the predicted risk is well below USEPA carcinogenic risk thresholds.

ES.4 COMPARISON TO ORIGINAL TASK 3A REPORT

With a few notable exceptions, the original Task 3A qualitative projections for 2020 are consistent with the findings of the current quantitative update. One important difference between this updated study and previous findings is the large increase in projected 2020 impacts due to CBNG development. While the original Task 3A study was based on preliminary Task 2 CBNG development production, this updated study used the final Task 2 projections for CBNG development, which were 15 to 30 percent greater than the earlier estimate. This increase suggests that while previously coal development was the most significant contributor to projected future year increases, based on this updated study, CBNG development may have a secondary, or even primary, contribution to air quality impacts. An additional change relative to the original Task 3A projections is the incorporation of new information on RFDs identified in the original Task 2 Report. Several coal-fired power plants had revised their permits since the original Task 2 and Task 3A reports, and expanded or reduced their power-generating capacity. Despite revisions to several of the tools used to analyze cumulative air quality, the overall findings and projected changes of this updated study generally are consistent with the original qualitative results for 2020.

Ambient impacts of PM_{10} continue to be a concern, as well as $PM_{2.5}$, at near-field locations and Class II areas located in proximity to the study area. While, generally, annual impacts are diminished relative to the original study, short-term impacts increased under some conditions. Essentially, coal mine operations and CBNG development would continue to dominate the PM_{10} impacts; the power plants would continue to dominate the SO_2 impacts (although they would continue to be below the standards); and the overall source groups would continue to contribute to NO_2 impacts, although impacts should remain below the national and state annual NO_2 standard.

Visibility impacts continue to be significant, and the predicted changes in the impact (number of days with greater than 10 percent change in extinction) for year 2010 are more than doubled in 2020 at some locations.

Based on modeling results, none of the acid deposition thresholds were exceeded at Class I areas for either the lower or upper development scenarios for 2020. However, there is a concern relating to the acid deposition into sensitive lakes. The model results showed that the increased deposition, largely from SO_2 emissions from power plants, exceeded the thresholds of significance for the ANC at two sensitive (high alpine) lakes. The results indicate that with increased growth in power plant operations, the reduced ANC of the sensitive lakes would become significant and would need to be addressed carefully for each proposed major development project.

ACRONYMS AND ABBREVIATIONS

μeq/L	micro equivalents per liter
$\mu g/m^3$	micrograms per cubic meter
ANC	acid neutralizing capacity
AQRV	air quality related values
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BCF	billion cubic feet
BLM	Bureau of Land Management
CBNG	coal bed natural gas
DM&E	Dakota, Minnesota, and Eastern
EA	environmental assessment
EIS	environmental impact statement
FLAG	Federal Land Manager's Air Quality Guidance
FS	U.S. Department of Agriculture-Forest Service
HAPs	hazardous air pollutants
IDLH	Immediately Dangerous to Life or Health
IR	Indian Reservation
kg/ha/yr	kilogram per hectare per year
km	kilometer
LBA	lease by application
LAC	limits of acceptable change
MDEQ	Montana Department of Environmental Quality
mmtpy	million tons per year
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NP	National Park
NRA	National Recreation Area
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 microns or less
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RELs	Reference Exposure Levels
RfCs	Reference Concentrations for Chronic Inhalation
RFD	reasonably foreseeable development
SAAQS	state ambient air quality standards
SO_2	sulfur dioxide
U.S.	United States
USEPA	U.S. Environmental Protection Agency
WA	Wilderness Area
WDEQ	Wyoming Department of Environmental Quality

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1.0 INTRODUCTION

The Powder River Basin (PRB) of Wyoming and Montana is a major energy development area with diverse environmental values. The PRB is the largest coal-producing region in the United States (U.S.); PRB coal is used to generate electricity both within and outside of the region. The PRB also has produced large amounts of oil and gas resources. Over the last decade, this region has experienced nationally significant development of natural gas from coal seams (coal bed natural gas [CBNG]).

BLM is required to complete a National Environmental Policy Act (NEPA) analysis (environmental impact statement [EIS] or environmental assessment [EA]) for each coal lease by application (LBA) as part of the leasing process. In the coal leasing EAs and EISs that have been prepared since the Powder River Regional Coal Team decertified the region in early 1990 (thereby allowing BLM to use the coal LBA process), cumulative impacts have been addressed in a separate section of the NEPA analyses to highlight the distinction between site-specific and cumulative impacts. With coal leasing continuing into the foreseeable future, and with impacts related to oil and gas development increasing beginning in the late 1990s due to development of coal bed natural gas (CBNG) in the PRB, BLM initiated studies and analyses to provide a consistent basis for evaluation of cumulative impacts in the coal leasing EISs. These studies and analyses included the PRB Coal Development Status Check (BLM 1996), Wyodak EIS (BLM 1999), PRB Oil and Gas EIS (BLM 2003), Montgomery Watson Harza (2003) study of PRB coal demand through 2020, and most recently, the PRB Coal Review.

Initiated in 2003, the PRB Coal Review includes the identification of current conditions (Task 1 reports), identification of reasonably foreseeable development (RFD) and future coal production scenarios (Task 2 Report), and predicted future cumulative impacts (Task 3 reports) in the PRB. All PRB Coal Review reports can be accessed from the BLM website.[1] For the air quality component of this study, the Wyoming PRB cumulative effects study area (**Figure 1-1**) comprises all of Campbell County, all of Sheridan and Johnson counties outside of the Bighorn National Forest lands to the west of the PRB, and the northern portion of Converse County. It includes all of the area administered by the Bureau of Land Management (BLM) Buffalo Field Office, a portion of the area administered by the BLM High Plains District Office, and a portion of the Thunder Basin National Grasslands, which is administered by the U.S. Department of Agriculture-Forest Service (FS). The Montana portion of the PRB cumulative effects study area for air quality (**Figure 1-1**) comprises the area of relevant coal mines including portions of Rosebud, Custer, Powder River, Big Horn, and Treasure counties. It encompasses the area administered by the BLM Miles City Field Office. State and private lands also are included in the study area.

The Task 1A Report for the PRB Coal Review, Current Air Quality Conditions (ENSR 2005a) documented the air quality impacts of operations during a base year (2002), using actual emissions and operations for that year. The base year analysis evaluated impacts both within the PRB itself and at selected sensitive areas surrounding the region. The analysis specifically looked at impacts of coal mines, power plants, CBNG development, and other activities. Results were provided for both Wyoming and Montana source groups and receptors.

[1] http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/prbdocs.html

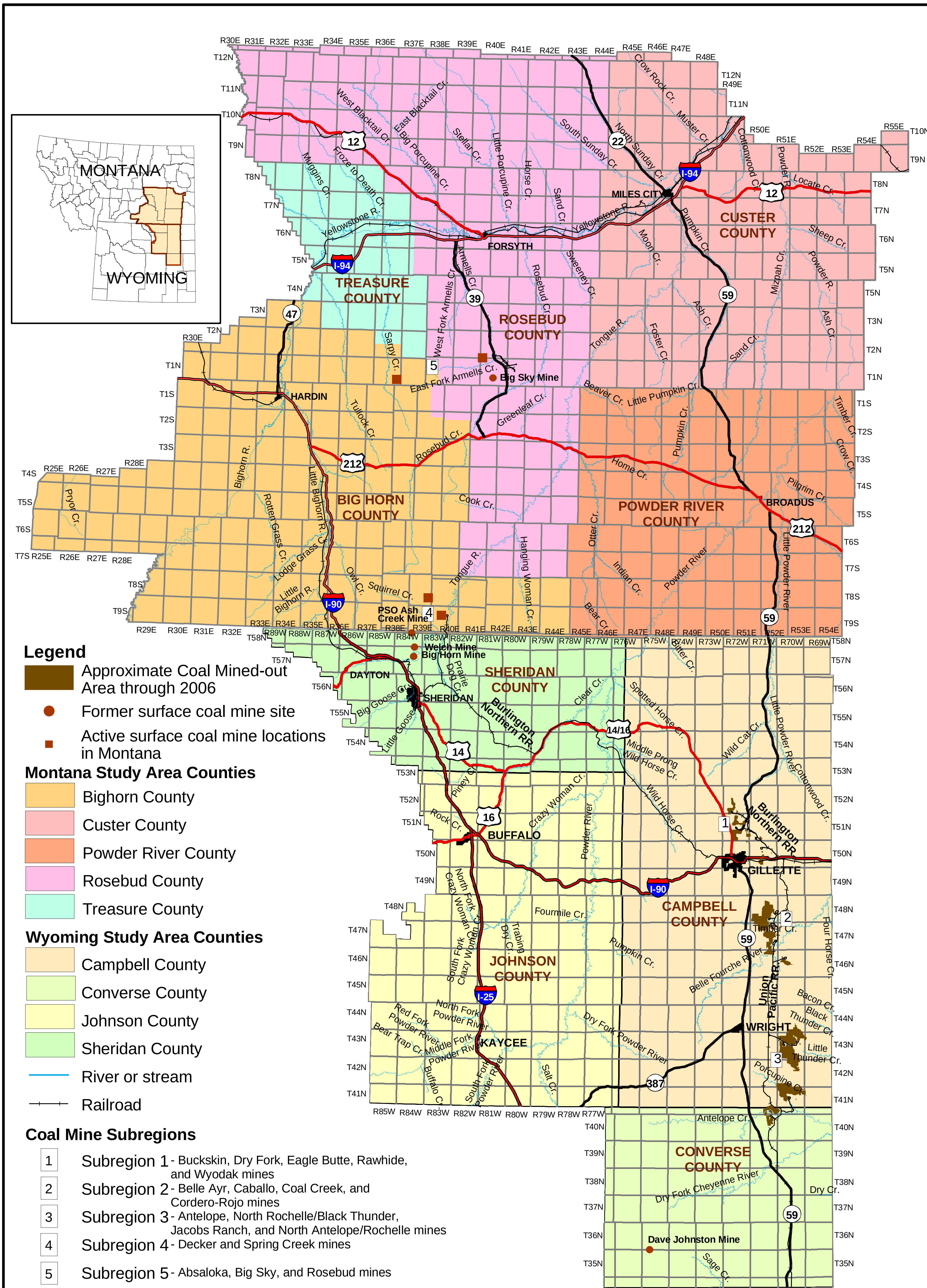
1.0 Introduction

The Task 2 component of the PRB Coal Review defined the past and present development actions in the study area that have contributed to the current environmental and socioeconomic conditions in the PRB study area. The Task 2 study also defined the projected RFD scenarios in the Wyoming and Montana PRB for years 2010, 2015, and 2020. The past and present actions were identified based on information in existing NEPA documents on file with federal and state agencies, and the Coal Development Status Check (BLM 1996). The identified RFD activities subsequently were evaluated as to their probability for occurrence. In order to account for the variables associated with future coal production, two detailed coal production scenarios (reflecting upper and lower production estimates) were projected to span the range of most likely foreseeable regional coal production levels and to provide a basis for quantification of development parameters that can be used to assess impacts. These future production levels were derived from the analysis of historic production levels and current PRB coal market forecasts, public and private information sources, and input from individual PRB coal operators; and they are summarized in the Task 2 report (ENSR 2005b). The RFD scenarios presented in the Task 2 Report provide the basis for the analysis of potential cumulative impacts in the Task 3 component of the study. The 2020 RFD scenarios from the Task 2 report were updated with current information, as applicable, and revised emissions were included in this updated analysis.

Due to the lack of detailed information for many developments beyond the next few years, the degree of uncertainty associated with the predicted developments and trends increases as the timeframe extends further into the future. As a result, the original Task 3A study (ENSR 2006) directly modeled RFD projections only for the year 2010. The original Task 3A study qualitatively evaluated cumulative air quality effects for years 2015 and 2020 based on the 2010 modeled impacts and the RFD projections from the Task 2 report. When the original Task 3A study was completed in 2006, the projected RFD activities for 2015 and 2020 had a higher level of uncertainty than is currently associated with revised projections. As the uncertainty associated with predicted developments for 2015 and 2020 decreased, it became increasingly valuable to update the original Task 3A qualitative estimates for 2015 and 2020 with a quantitative evaluation. In 2008, the cumulative air quality effects for 2015 were modeled, and the Task 3A study correspondingly was updated. The updated Task 3A report (ENSR 2008a) is referred to hereafter as the 2015 Update.[1]

This current update to the Task 3A report quantitatively updates the original Task 3A qualitative analysis of projected changes in impacts on air quality and air quality-related values (AQRVs) resulting from projected upper and lower RFD activities in 2020. This updated report is supplemental in nature and focuses exclusively on summarizing updated information and documenting any changes that have occurred since submittal of the original Task 3A Report and the 2015 Update. As the PRB Coal Review's underlying objectives and methodology have not changed since the 2015 Update report, this 2020 update to the Task 3A report does not reiterate this information, which is available in the 2015 Update (ENSR 2008a). Instead, this updated Task 3A Report details all technical changes relative to the 2015 Update report in Chapter 2.0, provides a summary of impacts for the projected 2020 scenarios in Chapter 3.0, and compares projected 2020 results to both the revised base year (2004) and to the previous qualitative projections from the original Task 3A report in Chapter 4.0.

[1] Available at http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/prbdocs.html



Powder River Basin Coal Review

Figure 1-1

Montana and Wyoming Study Area

Note: Approximate coal mined-out areas were not available for the Montana mine sites.

Source: BLM 2009.

11/09/09

1.1 Objectives

The PRB Coal Review is a regional technical study to assess cumulative impacts associated with past, present, and RFD in the PRB. The overall objectives of the PRB Coal Review have not changed from the original Task 3A Report. This current update to the Task 3A report furthers the objective of estimating the environmental impacts associated with RFD through the year 2020. The primary objective for updating the Task 3A report is to provide a quantitative evaluation of potential cumulative air quality effects for 2020.

Secondary objectives of this update are to develop the projected 2020 emissions using updated emissions from the base year (2004) and to compare the modeled impact to the previous qualitative evaluation for 2020. This objective is undertaken via a comparison of the original 2020 qualitative predictions to the quantitative evaluation performed here. Three important changes that affect the comparison of this updated report with the original Task 3A report include a new version of the dispersion model used to predict air quality and AQRVs, initiation of the dispersion model with a different meteorological year, and an improved base year emissions inventory. The 2015 Update report (ENSR 2008a) details these changes. This current update of the Task 3A report provides a summary of impacts for the projected 2020 scenarios, and compares projected 2020 results to both the revised base year (summarized in the 2015 Update report) and the qualitative projections from the original Task 3A report.

1.2 Agency Outreach, Coordination, and Review

The BLM directed the preparation of this PRB Coal Review. In order to ensure the technical credibility of the data, projections, interpretations, and conclusions of the study and ensure the study's usefulness for other agencies' needs, the BLM initiated contact with other federal and state agencies early in the study.

As part of this agency outreach and technical oversight, the BLM organized technical advisory groups. These groups were composed of agency representatives and stakeholders with technical expertise in the applicable resources. Participating agencies relative to air quality included the BLM; Wyoming Department of Environmental Quality (WDEQ); Montana Department of Environmental Quality (MDEQ); U.S. Environmental Protection Agency (USEPA); National Park Service; and FS. This technical advisory group provided comments on the original and 2008 modeling protocol (ENSR 2008b, 2005c). The 2008 modeling protocol was used for the 2015 Update and the current update for 2020; it provides additional details regarding the modeling approach and other technical details not presented in this report.

1.3 Methodology

The general methodology for updating the Task 3A report with quantitative estimates of 2020 cumulative air quality effects is unchanged relative to the original Task 3A approach used to produce quantitative estimates of 2010 cumulative effects, with the exception that Task 2 RFD projections for 2020 are the basis of the analysis rather than the projections for 2010.

1.0 Introduction

This study evaluates impacts at the same receptor groups for all of the same air quality metrics as the original Task 3A study. The evaluation of ambient air impacts includes the same pollutants (nitrogen dioxide [NO_2], sulfur dioxide [SO_2], particulate matter [PM] with an aerodynamic diameter of 10 microns or less [PM_{10}], and selected hazardous air pollutants [HAPs]), with the addition of PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Similar to the original study, the HAPs were evaluated at the near-field receptors in Montana and Wyoming, but not at the sensitive receptor areas. At the sensitive receptor areas, impacts on visibility and acid deposition also were evaluated. Like the original study, the updated study evaluates the changes in impacts for each of these fields for the projected levels of development. A comparison of the quantitative 2020 results to the qualitative 2020 projections from the original Task 3A report also is provided.

For the original Task 1A and Task 3A reports, potential impacts were modeled using meteorological data for 1996. For this current update and the previous 2015 Update to the Task 3A report, meteorological data for 2003 were used to evaluate air quality impacts in this updated study. The 2004 base year emissions inventory used for this current update is the same base year emissions inventory as was used for the 2015 Update.

For this updated Task 3A report, an updated future year emissions inventory and/or production ratios were used to estimate emissions for future year 2020. Base year emissions for most groups were increased to projected 2020 levels by a ratio that was calculated using production data for the projected development level divided by the production data for the base year. The future year scenarios then were modeled, and results were compared to base year impacts.

For this updated study, air quality impacts for the 2020 upper and lower production scenarios were modeled directly. The changes from the base year to the upper and lower development scenarios for 2020 subsequently are summarized. The summary includes a comparison of modeled ambient air quality impacts and AQRVs. The comparison includes discussion of modeled impacts relative to applicable state and federal standards and guideline values. Cumulative air quality effects predicted for 2020 also are compared to the original Task 3A qualitative results.

2.0 TECHNICAL APPROACH

2.1 Overview of Assessment Approach

The objective of the study is to evaluate impacts over a wide range of receptors centered over the PRB cumulative effects study area. The evaluation covers receptors within the PRB in both Montana and Wyoming, and it includes individual sensitive receptor groups in the region surrounding the PRB cumulative effects study area. Key aspects of the study include the selection of air emissions within the study area, the selection of a modeling system to conduct that evaluation, the selection of a receptor set (within the model system) to be used for evaluating cumulative impacts, and the selection of criteria for evaluation of impacts.

The 2020 air quality cumulative effects assessment for the PRB Coal Review, as presented in this updated Task 3A Report, evaluates the difference between modeled air quality impacts from the base year (2004) to the future year (2020) scenarios based on the projected change in emissions from the identified RFD activities. The model selected to assess cumulative air quality for both current and future conditions is the USEPA guideline model, CALPUFF. The USEPA's CALPUFF modeling system is a regulatory guideline model that was used in the original PRB Coal Review Task 3A (ENSR 2006), the 2015 Update (ENSR 2008a), and in the Montana Statewide Oil and Gas Supplemental EIS (ALL Consulting 2006). All of these studies were directed by the BLM and have identical modeling domain and receptor grids.

This update of the Task 3A report uses an identical model setup, meteorological input data, and base year emissions inventory as was used for the 2015 Update. Detailed information regarding the development of this input information is available in the 2015 Update report (ENSR 2008a) and its corresponding Technical Support Document (ENSR 2008d).

2.2 Air Quality Modeling

The CALPUFF model is a Lagrangian puff model with the capability to simulate regional-scale, long-range dispersion as well as local-scale, short-range dispersion (Scire et al. 2000a). The model was used for the original PRB Coal Review Task 3A (ENSR 2006), the Montana Statewide Oil and Gas Supplemental EIS (ALL Consulting 2006), and the 2015 Update Report (ENSR 2008a) to assess impacts over both near-field and far-field receptors. Since completion of the original Task 3A study (ENSR 2006), the USEPA has released a new guideline version of CALPUFF. The 2015 Update report, as well as this update to the Task 3A report, used the most recent approved version of CALPUFF. The modeling approach and technical options are identical between base year (2004) and predictive future year (previous 2015 Update and current 2020) cumulative analyses.

The CALPUFF modeling system used in this updated study has three main components:

- CALMET Version 5.8, Level 070623 (a diagnostic three-dimensional meteorological model, which develops the meteorological data for modeling input);
- CALPUFF Version 5.8, Level 070623 (the transport and dispersion model that carries out calculations of dispersion); and

- CALPOST Version 5.6394, Level 070622 (a post-processing package that is used to depict overall concentrations and impacts).

The CALPUFF modeling domain was established to be identical to that used in the PRB Oil and Gas Final EIS (BLM 2003), the original PRB Coal Review (Task 1A report [ENSR 2005a] and Task 3A report [ENSR 2006]), and the Montana Statewide Oil and Gas Supplemental EIS (ALL Consulting 2006). The CALPUFF modeling domain, study area, and sensitive areas are shown in **Figure 2-1**. The modeling domain includes most of Wyoming and Montana, and extends into the states of Idaho, Utah, Nebraska, and North and South Dakota.

The receptor sets established for the original PRB Coal Review (Task 1A and Task 3A) are identical to the receptor sets used in this updated study. These selected receptor sets include: near-field receptors in both states, which cover the study area; receptors along boundaries and within the Class I and sensitive Class II areas identified by the technical advisory group; and other sensitive receptors, such as lakes. The locations of all receptors are shown in **Figure 2-2** and are described in detail in the original Task 3A Report (ENSR 2006), as well as the modeling protocols (ENSR 2005c, 2008b).

2.3 Meteorological Data and Analyses

The meteorological data set for 2003 was selected as the worst-case meteorological year based on an analysis of visibility impacts at the nearest Class I areas for the base year (2004). The meteorological year 2003 was used to model all impacts presented in this updated report.

2.4 Emissions Input Data

The objective of the air quality component of the PRB Coal Review, including the 2020 update for the Task 3A report, is to assess the predicted change in air quality and related impacts given a predicted change in RFD-related activities in the PRB. The key assumptions used for the update to the Task 3A report include the following:

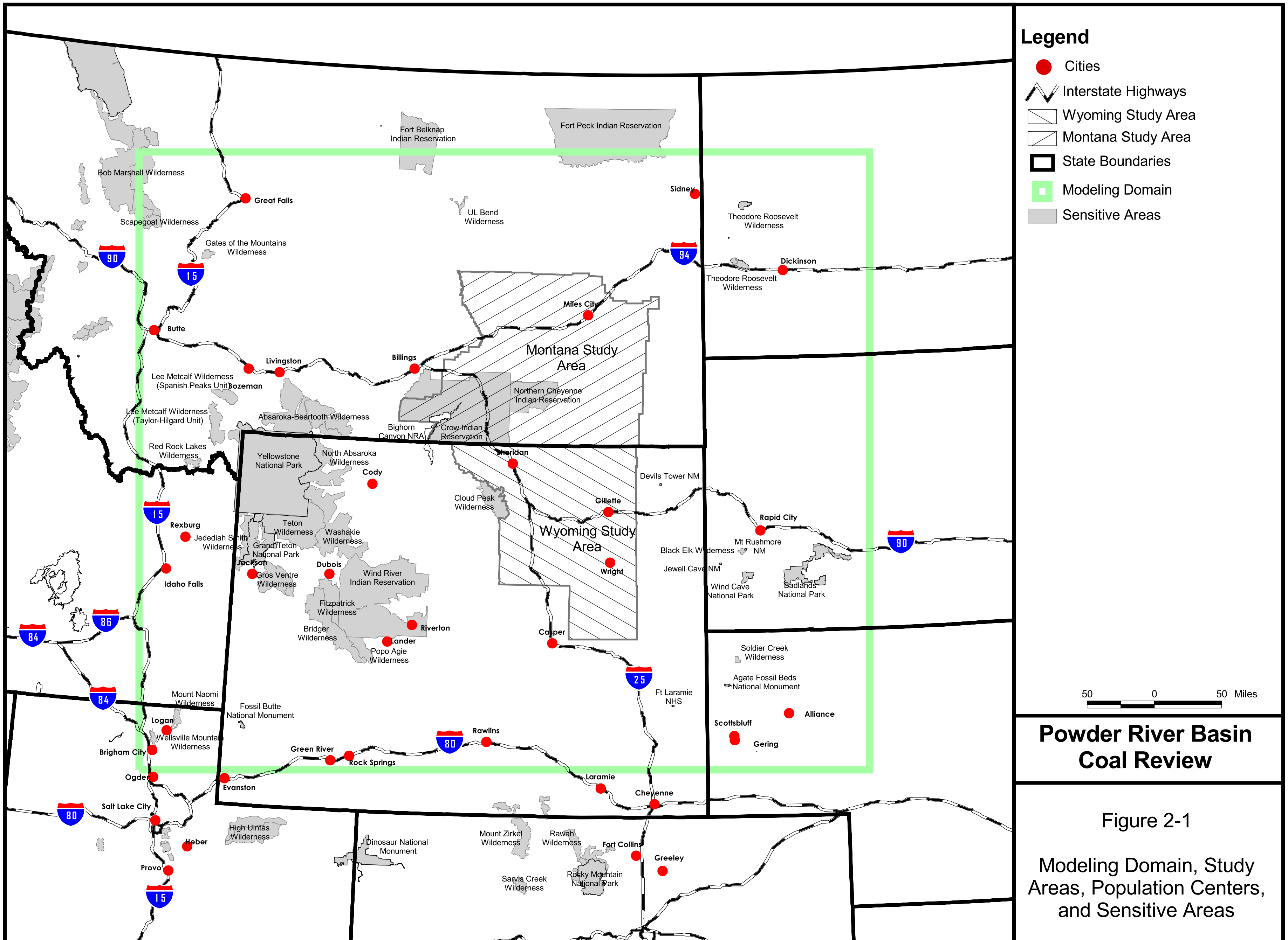
- Where actual source characteristics (e.g., stack height, temperature, etc.) exist in provided emissions inventories, they were used. Where source characteristics were lacking, representative source characteristics generically were developed for each source type;

- A state-specific emission rate, determined by state-specific presumptive-best available control technology (BACT) levels, were applied to minor group sources (e.g., CBNG sources);

- USEPA regulations mandating future use of ultra-low sulfur fuels and future model engine emission limits were not incorporated into future year emissions due to the level of uncertainty surrounding the rate of replacement of existing engines and implementation of these regulations;

- No specific facility boundaries (for ambient air) were developed for individual sites; and

- Emissions were broadly characterized and do not represent actual short-term emission rates.

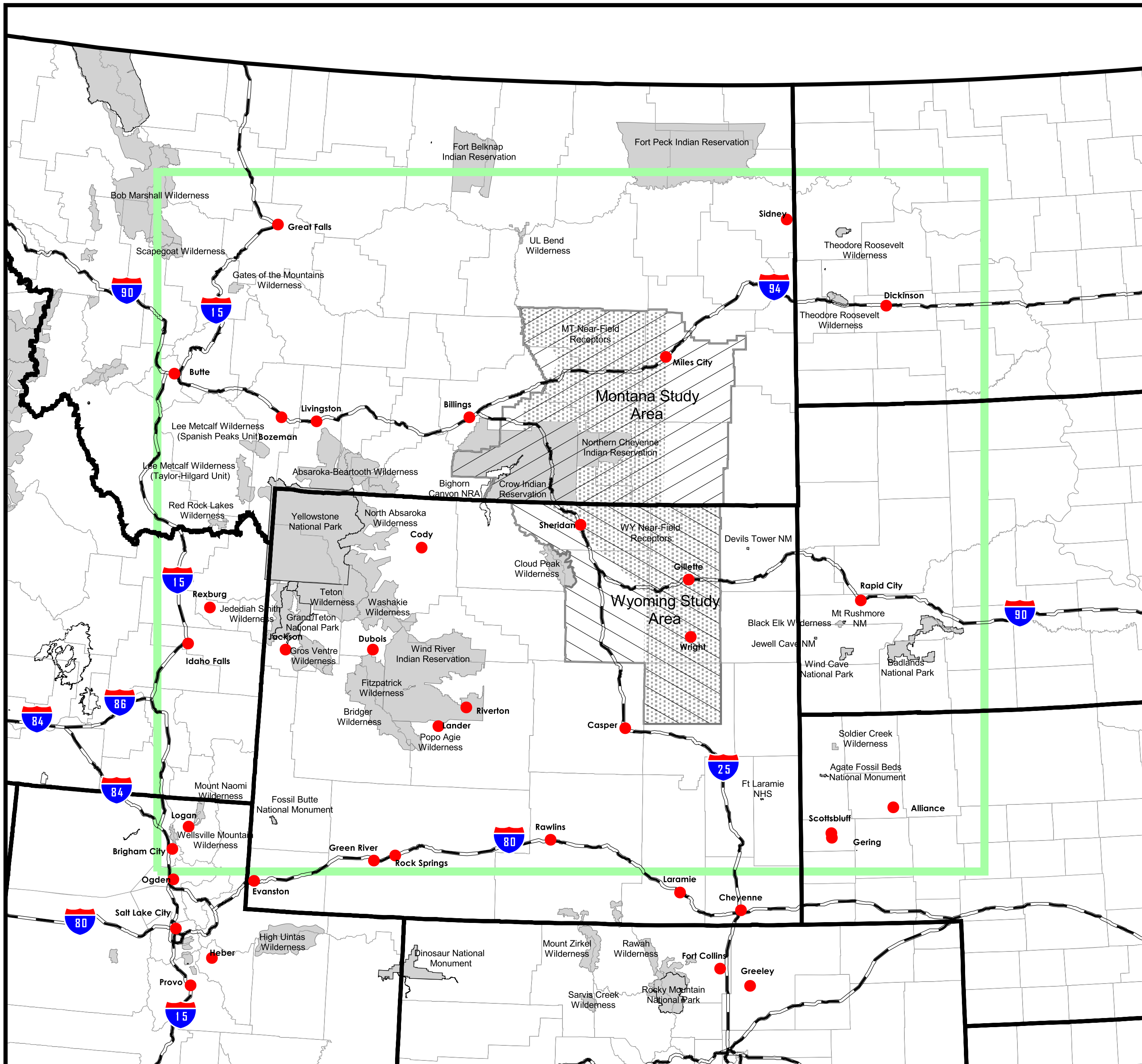


Powder River Basin Coal Review

Figure 2-1

Modeling Domain, Study Areas, Population Centers, and Sensitive Areas

12/15/05



Legend

Cities
Interstate Highways
Wyoming Study Area
Montana Study Area
State Boundaries
Modeling Domain
Sensitive Areas
Near-field Receptors

50 0 50 Miles

Powder River Basin Coal Review

Figure 2-2

Receptor Locations for Sensitive Areas and Near-field Receptors

12/15/05

The emission sources were separated into various emission source groups for separate analyses. For regional modeling of this magnitude, it is not expected that a single source would dominate predicted impacts. Rather, for a more detailed understanding of projected changes in 2020, it is beneficial to compare impacts resulting from source types (e.g., CBNG, coal mining, etc.), or source locations (e.g., Montana, Wyoming, or other states). In this manner, the dominant source types or source locations can be more easily identified for future planning efforts. The emission source groups for which separate modeling results were analyzed included:

- All sources combined
- Coal production-related sources (from both states, including mines, power plants, railroads, and coal conversion facilities) (Note: the Tongue River Railroad only was included in the upper development scenario for 2020)
- Coal mines (in both states)
- Montana sources (all sources located in Montana)
- Wyoming sources (all sources located in Wyoming)
- CBNG sources (all CBNG producing sources)
- Power plants (includes coal- and gas-fired power plants in Wyoming and Montana)
- Non-coal sources (roads, urban areas, miscellaneous sources, conventional oil and gas, non-coal power plants [excludes CBNG sources]).

Current emissions from other non-coal sources, such as major roads, railroads, and urban areas, were included as separate source groups; however, it should be noted that this study only includes non-coal sources within the study area (Campbell, Johnson, Sheridan, and most of Converse counties in Wyoming; Rosebud, Custer, Powder River, Big Horn, and Treasure counties in Montana) (see **Figure 1-1**).

The 2004 emission inventory developed for the Montana Statewide Oil and Gas Supplemental EIS (ALL Consulting 2006) was used as the revised base year emissions inventory for the current update of the cumulative air quality analysis.

Although, $PM_{2.5}$ emission rates were not uniformly available in the provided emission inventory, with the promulgation of $PM_{2.5}$ national and state ambient air quality standards (NAAQS and SAAQS, respectively), an estimate of total $PM_{2.5}$ impacts was valuable for a comprehensive evaluation of the PRB cumulative air quality effects. Therefore, total $PM_{2.5}$ impacts were indirectly estimated based on a ratio of monitored PM_{10} concentrations that were representative of impacts from sources in the region. The Lame Deer monitoring station, a site representative of the PRB study area, measures both ambient PM_{10} and $PM_{2.5}$ at a co-located site. The annual average ratio of ambient $PM_{2.5}$ to PM_{10} was calculated to be 0.35 during 2005, which is the only recent year with data recovery over 80 percent for both $PM_{2.5}$ and PM_{10}. This ratio was used to scale the modeled PM_{10} impacts to estimate $PM_{2.5}$ impacts. While evaluation of short-term $PM_{2.5}$ was limited by this technique, it is anticipated that annual $PM_{2.5}$ impacts would be appropriately representative for a region with similar sources.

Previously, the Task 2 analysis projected future year production estimates for various resources. The results summary from the Task 2 report are presented in **Table 2-1**. The changes in production were used to project emissions for the base year for this report (2004) to 2020. The methodology used to calculate emission rates for each emission source group is presented below.

Table 2-1
Emissions Calculations for 2020 by Source Group

	Production Data			Adjustment Ratio		
Source Group	**Base (2004)**	**Lower Scenario (2020)**	**Upper Scenario (2020)**	**Base (2004)**	**Lower Scenario (2020)**	**Upper Scenario (2020)**
Conventional Oil and Gas Sources	39.9 BCF	35.1 BCF	35.1 BCF	1.0	0.880	0.880
CBNG Sources	338 BCF	631 BCF	631 BCF	1.0	1.867	1.867
Coal Production (Wyoming)	363 mmtpy	495 mmtpy	576 mmtpy	1.0	1.364	1.587
Coal Hauling (Wyoming)	363 mmtpy	495 mmtpy	576 mmtpy	1.0	1.364	1.587
Coal Production (Montana)	36.1 mmtpy	56 mmtpy	83 mmtpy	1.0	1.551	2.299
Power Plants	Individual Plant Adjustments					
Urban Areas	No Adjustment					
Miscellaneous	No Adjustment					

Note: BCF = billion cubic feet
mmtpy = million tons per year

Coal Production-related Sources

For coal production-related sources, which included mines, power plants (discussed separately below), railroads, and coal conversion sources, 2004 data were used to establish representative base year conditions. Two coal development scenarios were analyzed to estimate emissions rates for the future year, a lower production scenario and an upper production scenario. The projected increase in coal production under the lower and upper production scenarios were used to scale the base year emissions to the future year emissions, as a ratio of the base year production to the projected production.

As shown in **Table 2-1**, different lower production and upper production values were applied to sources in Wyoming and Montana. The lower and upper coal production values for Wyoming are presented in Tables A-1 and A-2 of the Task 2 report (ENSR 2005b), and the lower and upper coal production values for Montana are presented in Tables A-3 and A-4 of the Task 2 report.

Several RFD coal production-related sources were identified for future year 2020 as part of the Task 2 report (ENSR 2005b). These sources were not operational during the base year (2004) and, therefore, were not included in the base year emissions inventory. An emissions inventory for these RFD sources was developed and incorporated into the 2020 modeling for this updated Task 3A report. RFD coal production-related sources include: new coal mines, new rail lines to transport the coal, coal conversion facilities, and coal-fired power plants (new power plants are described in the power plant section of this chapter).

Three RFD mines were included in the emissions inventory for this 2020 analysis. The Otter Creek Mine and Kinsey Mine in Montana are projected to be developed under the upper 2020 development scenario, but not under the lower development scenario. Figures A-3 and A-4 of the Task 2 report show the projected locations of these mines. The School Creek Mine (a newly identified RFD mine) is projected to be developed in the Subregion 3 coal mine area near Wright, Wyoming. The School Creek Mine was included in both the upper and lower development scenarios. Per information provided by the BLM (2009) the RFD estimated 2020 coal production from the Wyoming mines (**Table 2-1**) would not change as a result of the School Creek Mine development; rather the projected coal production from this new RFD mine would be offset by reduced production at the existing mines in Subregion 3. Therefore, the total coal mining emissions are consistent with Task 2 2020 projections; however, the spatial distribution of emissions differs slightly from the base year due the addition of these three new production areas.

Per the Task 2 report, it was projected that the Tongue River Railroad would not be constructed under the lower 2010 production scenario; however, it was included in the upper 2010 production scenario. This same approach was used in this updated analysis for 2020. Construction of this railroad under the upper production scenario would be dependent on development of the Otter Creek Mine in Montana. The analysis in the Draft Supplemental EIS for the Tongue River Railroad (Surface Transportation Board 2004) concluded that air quality-related impacts from railroad operations would not adversely affect the Northern Cheyenne Indian Reservation (IR).

Emissions from the proposed Dakota, Minnesota, and Eastern (DM&E) rail line expansion into the PRB were not included in the base year. Per the Task 2 Report, it was projected that this railroad would not be operational until 2015. Emissions from the DM&E were included in the upper and lower production scenarios for the 2015 Update and this current update for 2020. Only the portion of the DM&E expansion line located in the PRB study area was included in this updated analysis. Emissions were based on information presented in the Draft EIS (Surface Transportation Board 2000) for the proposed rail line.

Several existing rail lines are projected to increase their capacity in Wyoming by 2020. The increase in emissions associated with expanded carrying capacity is modeled using the scaling factor for coal hauling activities shown in **Table 2-1**. It is expected that there would be no change in the spatial location of these existing rail lines.

Two RFD coal conversion facilities are projected to be developed by 2020 based on the update of the Task 2 report (AECOM 2009). One coal to liquid plant (CTL) would be developed in Wyoming, and another coal conversion plant would be built in Montana. In the absence of additional information, the modeled emissions and release parameters were developed based on the North Rochelle CTL plant permit. Both coal production-related RFD sources were included in upper and lower development modeling as part of the “coal-related” source group (not listed in **Table 2-1**).

<u>CBNG Sources</u>

CBNG activity was evaluated separately from conventional oil and gas production for this study. Conventional oil and gas impacts were included in non-coal sources (see below). For CBNG sources, 2004 base year emissions data were scaled based on projected increases in production. The projected increase in CBNG production was based on the ratio of base year gas production to projected gas production, as presented in the Task 2 report (ENSR 2005b) and shown in **Table 2-1**.

It is projected that the spatial distribution of CBNG wells in the Wyoming PRB would change between the base year and 2020. For this updated Task 3A report, a new spatial distribution of wells was modeled for Wyoming CBNG sources. Similar to the CBNG emissions inventory for the base year in the original Task 3A report and the 2015 Update, well locations were gridded, and emissions from all wells within a single cell were modeled at the center point of the cell. This approach produces conservative results as the emissions are more spatially concentrated.

Other Non-coal Sources

Other non-coal sources included conventional oil and gas production, for which projected emissions increases were based on data developed from expected increases in conventional oil and gas activity. For other sources (urban areas, non-coal highways, and miscellaneous sources), there was no adjustment to the emission rates from the base year. For all non-coal sources, the same emission rates were used for both the lower and upper production scenarios. Many of these source emissions were developed from the original PRB Coal Review 2002 source emissions data base.

Power Plant Sources

Emissions from existing power plants in the study area, and the Dave Johnson Power Plant located outside of but adjacent to the study area, are included in the base year. For existing coal-fired power plant sources that were operational in the base year, a scaling factor was used to increase the capacity of these sources from an 88 percent capacity factor in the base year to a 90 percent capacity factor in both future year scenarios to account for a potential increase in capacity. There were no projected increases in emissions for gas-fired power plants.

For coal-fired power plants, the projected emission rates for power plants that were not operational in the base year but were projected to be operational in future years were derived from the actual power plant permit application or the power plant permit from the specified facility. This information provides for a conservative estimate since permitted emission rates are the maximum allowable emission rates. Actual emission rates from RFD power plants could be less than the allowable emissions. Where stack parameters were available, those data were used for input into the model. Emissions of NO_X, SO_2, and PM_{10} from the power plant permits were based on expected levels with BACT that would be applied to those sources. Where a coal-fired power plant permit application or permit was not available, emissions from a coal-fired power plant of equivalent size were used to estimate future year emissions. The RFD coal-fired power plants for which emissions were estimated include the following:

- WYGEN 2 and 3
- Two Elk Unit 1 and 2
- Dry Fork (also known as Basin Electric/Gillette)
- Hardin Generating Station
- Otter Creek Power Plant
- One additional 700-kilowatt of energy production (2020 upper production development scenario only)

These coal-fired power plants were included as individual sources, in addition to the existing coal-fired facilities that also were analyzed.

Projected RFDs previously identified in the Task 2 Report (ENSR 2005b) were re-evaluated as part of the 2015 Update, and updated information was incorporated into the 2015 Update report. No changes to RFD power plants were identified since the 2015 Update, with the exception of adding two RFD power plants: Otter Creek and an additional power plant in Wyoming.

3.0 PREDICTED CUMULATIVE AIR IMPACTS

3.1 Modeled Cumulative Impacts 2020

Using the model and source groups discussed in Chapter 2.0, the modeling effort determined impacts of each of the source groups on each of the receptor groups for the 2020 lower and upper production scenarios.

A summary of the key findings for each of the air quality components is provided in **Table 3-1**. The detailed analyses for each of the components are provided in this chapter. In general, the results of this modeling study support the findings presented in the Task 1A, original Task 3A, and 2015 Update reports, and extend the impacts that had been identified in those studies.

Table 3-1
Summary of Modeled Air Quality Impacts

Air Quality Metric		Base Year Impacts	Year 2020 Impacts
Concentrations	Criteria	Impacts are below NAAQS and SAAQS, except short-term PM_{10} and $PM_{2.5}$ in the near-field	Short-term and annual $PM_{2.5}$ and short-term PM_{10} are above applicable NAAQS and SAAQS at localized points.
	HAPs	Less than the RELs and RfCs for all HAPs	Less than the RELs and RfCs for all HAPs
Visibility	Far-field	Northern Cheyenne IR, Badlands NP, Wind Cave NP, and several Class II areas have more than 200 days with greater than 10 percent change in visibility	The observed spatial extent of visibility impacts increases with development. The number of days with greater than a 10 percent change in visibility increases by 0 to 60 days per year.
Atmospheric Deposition-Sulfur	level of concern	Below 5 kilograms per hectare per year (kg/ha/yr)	Below 5 kg/ha/yr
Atmospheric Deposition-Nitrogen	level of concern	Below 1.5 kg/ha/yr	Below 1.5 kg/ha/yr
Atmospheric Deposition-Lake Chemistry	ANC	Impacts above threshold values at one lake	Development increases impacts above the LAC[2] for one lake

[1]Nitrogen and sulfur deposition thresholds are published in Fox et al. (1989). The FS does not consider these values to be sufficiently protective of all areas and are currently in the process of revising these. The new nitrogen level of concern is 1.5 kg/ha/yr based on a study by Baron (2006). All predicted nitrogen deposition values are below the 1.5 kg/ha/yr level of concern.

[2]LAC refers to a 10 percent change in ANC for lakes with an ANC of 25 micro equivalents per liter (µeq/L) or more, or a threshold of 1 µeq/L for lakes with less than 25 µeq/L ANC.

Note: SAAQS = State Ambient Air Quality Standards
ANC = acid neutralizing capacity
LAC = limits of acceptable change
NAAQS = National Ambient Air Quality Standards
RELs = Reference Exposure Levels
RfCs = Reference Concentration for Chronic Inhalation
IR = Indian Reservation

It is important to note that the effects of Best Available Retrofit Technology (BART) implementation were not incorporated into the presented results, since the states are still developing their implementation plan. BART implementation primarily will target emission reductions of NO_x and SO_2, precursors to particulates most involved in visibility reduction. It is anticipated that the modeled air quality effects summarized as part of this report likely would be reduced as a result of BART regulations; however, the level of reduction cannot be determined at this time.

3.1.1 Impacts on Ambient Air Quality

Using the receptor grids identified in Chapter 2.0 along with the source groupings, the model was used to predict the impacts at each receptor point in the receptor grid. For this analysis, the results are provided for the maximum receptor in each group, which may not be the same receptor in each of the modeling scenarios. Impacts may occur at different receptors for each of the modeling scenarios, but changes in location of the maximum receptors are not identified in these results. The Technical Support Document (TSD) (ENSR 2008d) contains plots of predicted concentrations for near-field receptors.

The analysis does not separate the sources into Prevention of Significant Deterioration (PSD) increment-consuming and non-PSD increment-consuming sources. Therefore, the results cannot be used to develop a pattern of increment consumption for a particular site. The PSD increment level comparisons are for informational purposes only and do not constitute a regulatory PSD increment level consumption analysis, which would be required for evaluating larger projects by air permitting authorities.

The model results also are limited by certain assumptions regarding sources and receptors. The source characterizations are based on available data, and do not represent specific stacks or sources of fugitive emissions. The modeling sources generally are provided by area or volume, to represent multiple sources within each specified facility. The specific fence lines or exclusion areas around a modeled source also are not identified in this study. The results cannot, therefore, be interpreted as evaluating maximum impacts that might occur at the boundary or fence line of a specific source. The receptors in the near-field grid in both states were removed from modeling if their location was within 1 kilometer (km) of any source. There were several Wyoming near-field receptors located less than 1 km from modeled CBNG source locations. Results from these receptors were not included in summary tables or plots. Removal of these receptors ensured that results were representative of the broad area in the PRB study area, rather than unduly affected by a specific source. However, there are still receptors with high impacts due to a single source-receptor relationship.

Additional assumptions were made to aid in the interpretation of ambient impacts. Generally, only NO_x emission rates, and not NO_2, were provided in the emission inventory. Therefore, the maximum NO_2 impacts are assumed to be 75 percent of the maximum NO_x impacts, a standard USEPA approved method (40 Code of Federal Regulations 51, Appendix W). As was discussed in Chapter 2.0, $PM_{2.5}$ emission rates were not available in the emissions inventory as $PM_{2.5}$; instead, $PM_{2.5}$ impacts were estimated based on modeled PM_{10} emissions scaled by an annual-average ratio of ambient $PM_{2.5}$ to PM_{10}. While evaluation of short-term $PM_{2.5}$ is limited by this technique, it is anticipated that the overall magnitude of annual $PM_{2.5}$ impacts is approximately representative for a region with similar sources.

All ambient air quality impacts presented in this report generally are consistent with the definition of the standard. The annual impacts are the maximum value (first highest) for each area. Reported air quality impacts for 3-hour and 24-hour averaging periods are highest second high value at each receptor. The maximum (first highest) 1-hour impacts are reported for receptors within the state of Montana.

Ambient air quality results for specific receptor groups are presented in a series of bar graphs as discussed in Section 3.1.1.1. The graphs show each source group's maximum impacts for the base year (2004) and the 2020 upper and lower production scenarios. Data are provided for each ambient standard and PSD increment level for NO_2, SO_2, and PM_{10}, and the ambient standard for $PM_{2.5}$. It is important to note that the location of the maximum impact that results from one source group is not necessarily the same location as the maximum impact for another source group. Additionally emissions sources are aggregated into multiple source groups (e.g. coal-fired power plants are included in two source groups: power plants, and coal-related sources); therefore, the results for each source group are not additive.

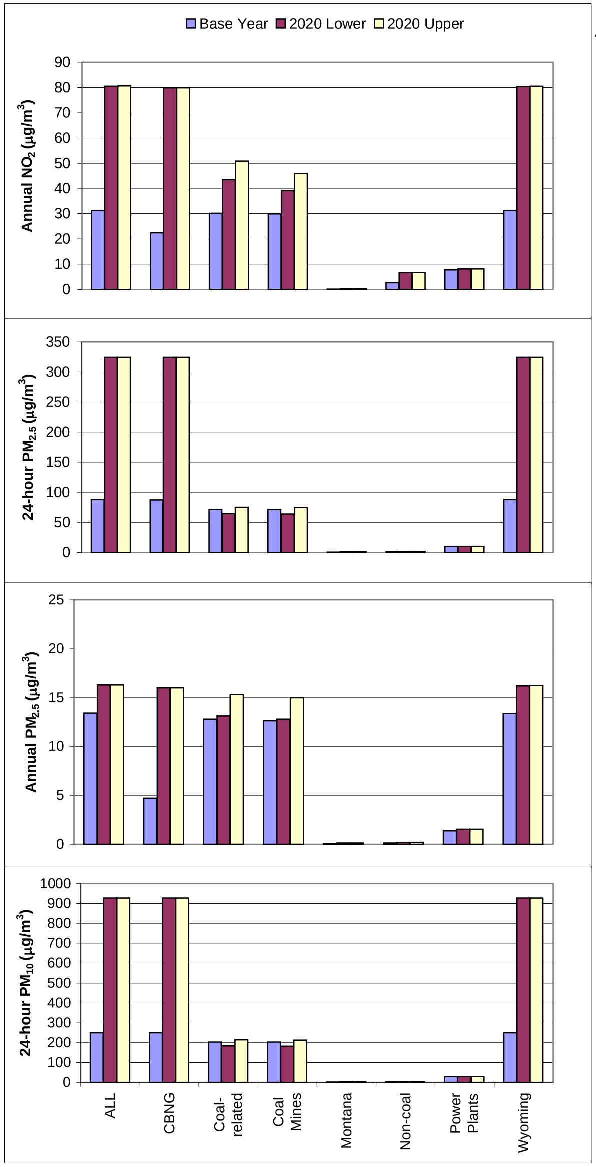
3.1.1.1 Impacts at Near-field Receptors in Wyoming

Results for the near-field receptor grid for Wyoming are presented in **Figure 3-1**. The maximum modeled impacts on Wyoming near-field receptors that result from each individual source group are identified in the figure. Based on modeling results for PM_{10}, in Wyoming, the maximum 24-hour PM_{10} and $PM_{2.5}$ impacts are predicted to exceed the NAAQS (150 micrograms per cubic meter [$\mu g/m^3$] and 35 $\mu g/m^3$, respectively) for the base year as well as for both of the 2020 scenarios, primarily as a result of CBNG operations and coal mining activities. The combined impacts from all sources for the 2020 upper production scenario are predicted to be nearly four times the standard for PM_{10} and six times the standard for $PM_{2.5}$. NO_2 and SO_2 impacts are all below their respective standards. **Figure 3-2** provides a spatial depiction of the 24-hour PM_{10} impacts at the near-field receptors from all sources. For the 2020 upper production scenario, the modeled impacts are above 150 $\mu g/m^3$ for several areas surrounding coal mines and CBNG activities in the Wyoming PRB. It is assumed that the level and spatial extent of the modeled exceedances are an over-prediction since future locations of activities are roughly estimated. The approach used in this analysis scaled base year emissions based on projected 2020 production levels at aggregated well locations, which produces conservatively high impacts. The location of maximum modeled impacts and spatial pattern of the 24-hour $PM_{2.5}$ impacts for the 2020 upper production scenario are very similar to PM_{10}, as shown in **Figure 3-3**. The only substantial difference is that the small areas in **Figure 3-2** with predicted SAAQS exceedances are somewhat larger for $PM_{2.5}$. A large portion of the short-term impacts for all scenarios are associated with CBNG sources.

Figure 3-4 shows the modeled extent of the annual $PM_{2.5}$ impacts for the 2020 upper production scenario for all sources. This is similar to the spatial pattern depicted in **Figure 3-3**, except the maximum impacts are slightly above SAAQS, and maximum values are limited in their spatial extent. For the 2020 production scenarios, the modeled impacts of the annual $PM_{2.5}$ levels would be above the Wyoming and national standard (15 $\mu g/m^3$) at the maximum receptor in Wyoming. The annual PM_{10} spatial pattern is similar to the spatial pattern shown for annual $PM_{2.5}$; however, maximum impacts are predicted to be below SAAQS.

The modeled base year impacts of NO_2 generally were about one-third of the annual standard, increasing to approximately three-quarters of the annual standard under the upper production scenario. The CBNG operations are predicted to be the largest contributor to the maximum NO_2 impacts with a secondary contribution from coal-mining activities. The combined Wyoming sources

Figure 3-1
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$ at Wyoming Near-field Receptors



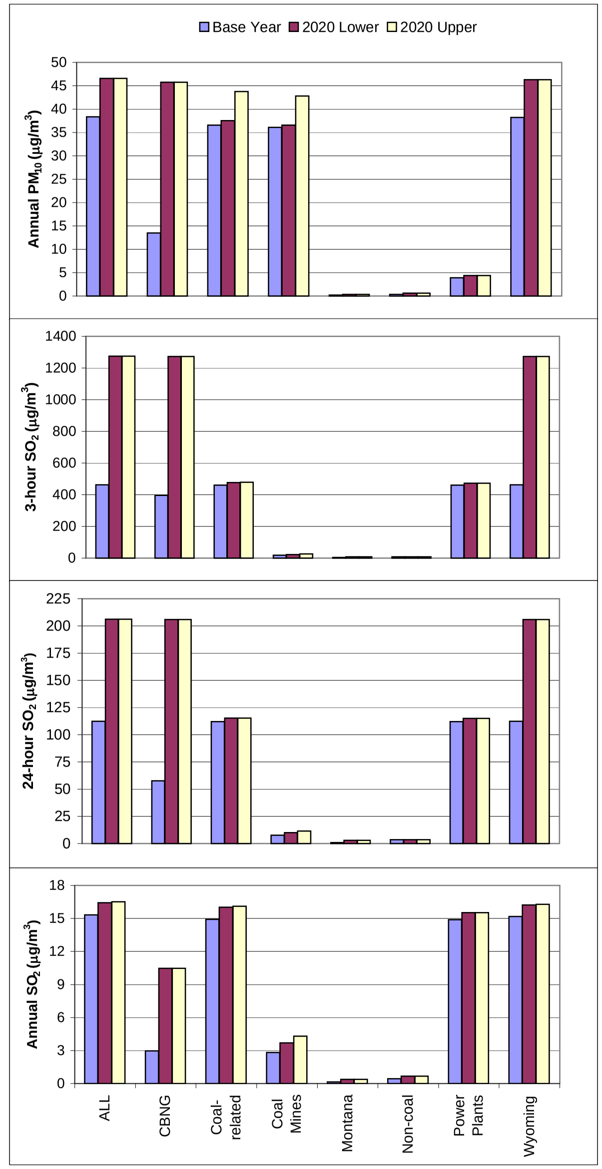
Applicable Standards/ PSD Increments (μg/m3)

NAAQS: 100
PSD: 25

NAAQS: 35

NAAQS: 15

NAAQS: 150
PSD: 30



Applicable Standards/ PSD Increments (μg/m3)

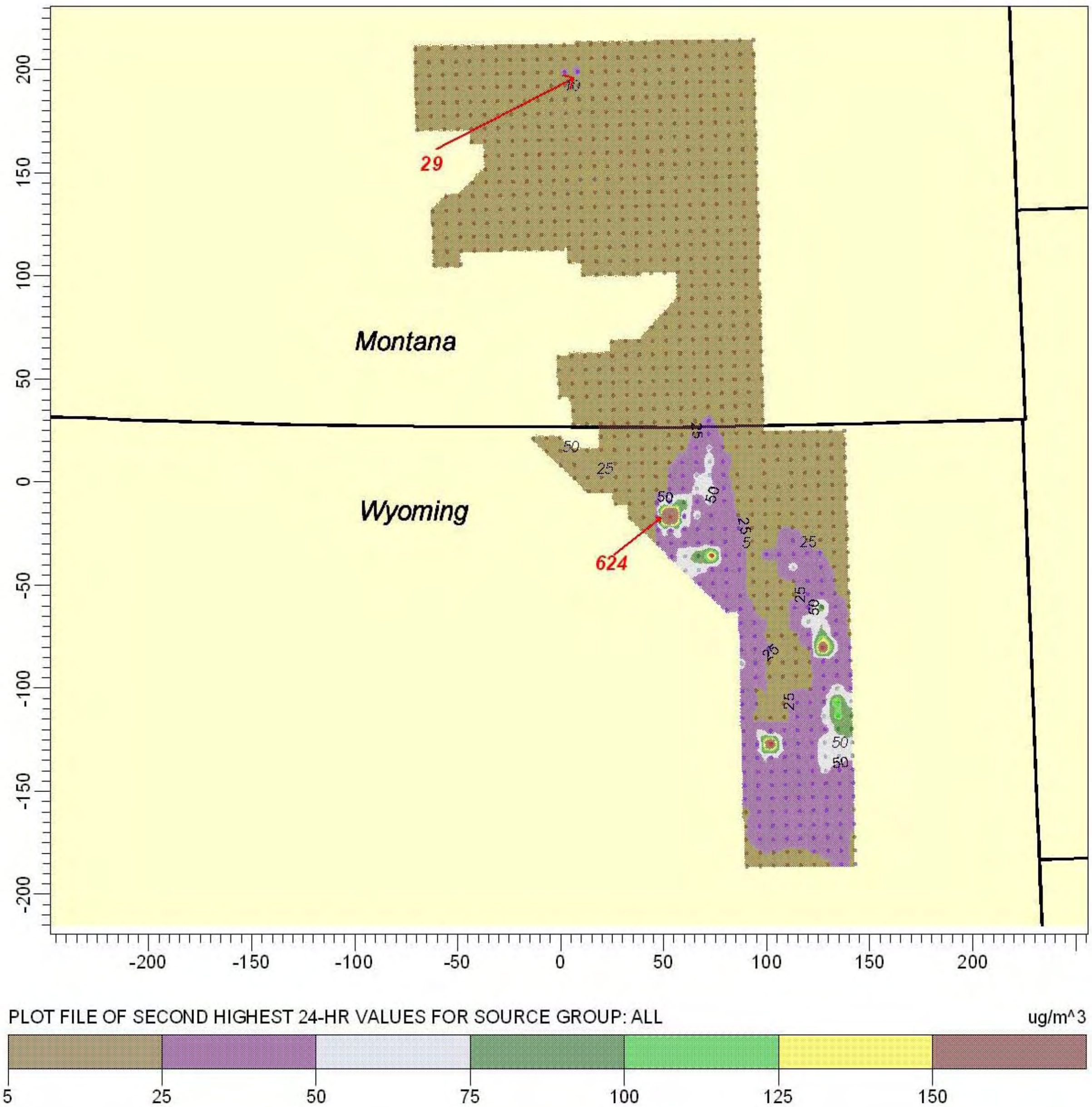
PSD: 17
Wyoming SAAQS: 50

NAAQS: 1,300
PSD: 512

NAAQS: 365
PSD: 91
Wyoming SAAQS: 260

NAAQS: 80
PSD: 20
Wyoming SAAQS: 60

Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario



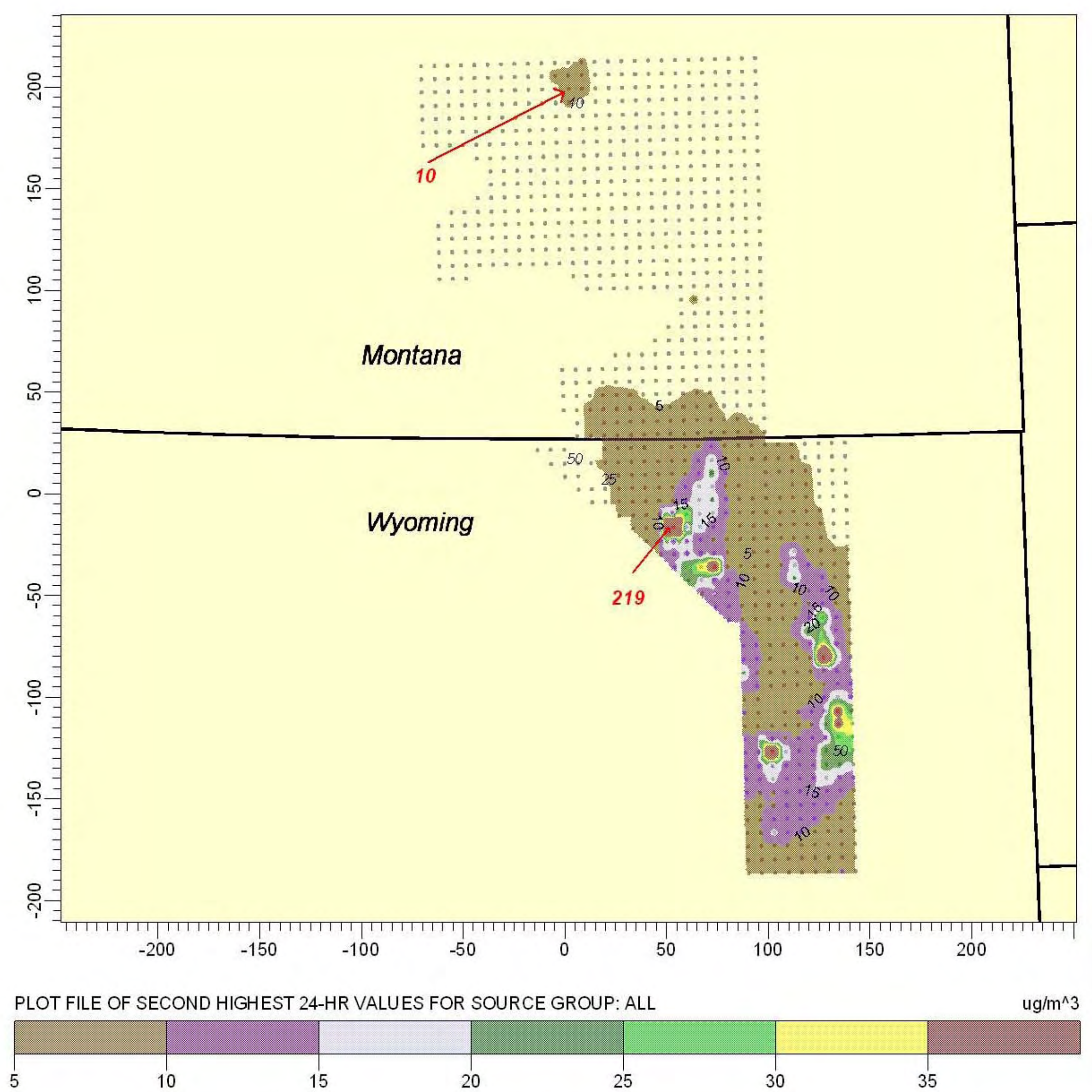
Note: Includes all sources.

Powder River Basin Coal Review

Figure 3-2

24 Hour PM_{10} Concentrations for Near-field Receptors - 2020 Upper Production Scenario

08/20/09



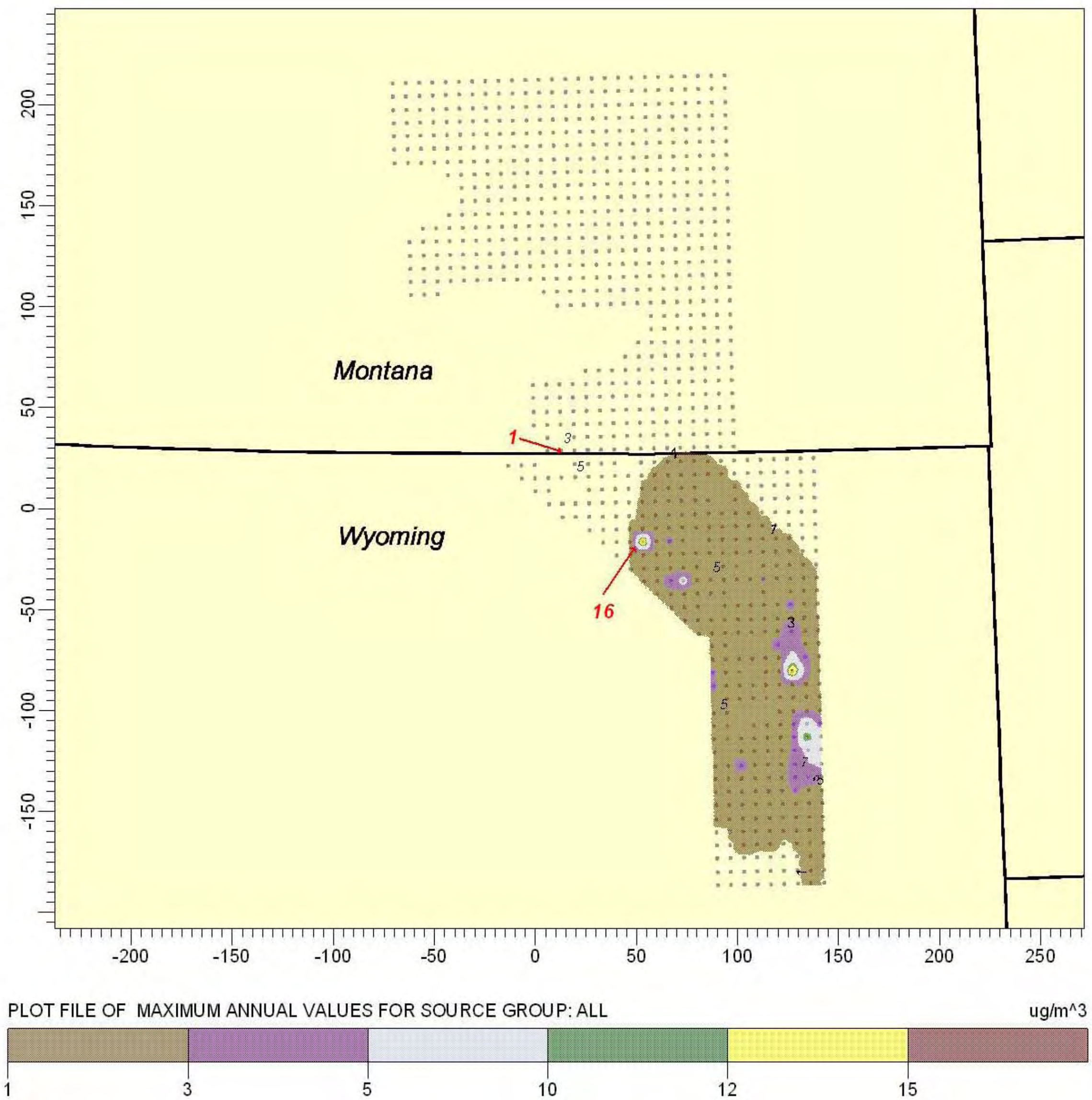
Note: Includes all sources.

Powder River Basin Coal Review

Figure 3-3

24 Hour $PM_{2.5}$ Concentrations for Near-field Receptors - 2020 Upper Production Scenario

08/20/09



Powder River Basin Coal Review

Figure 3-4

Annual $PM_{2.5}$ Concentrations for Near-field Receptors - 2020 Upper Production Scenario

Note: Includes all sources.

08/20/09

would be responsible for virtually all of the NO_2 impacts in Wyoming. While modeled NO_2 concentrations are above the PSD increment levels at the maximum receptor in Wyoming, the result is not a direct evaluation of PSD increment consumption. The regulatory agency has the authority and responsibility to determine if an exceedance or violation has occurred.

The modeled impacts of SO_2 emissions are below the ambient standards for the 3-hour and 24-hour averaging periods for both the upper and lower development scenarios and are well below the annual standards. Modeled impacts are above the PSD Class II increment levels for short-term periods. Generally, it appears that the 3-hour and 24-hour impacts for all scenarios are associated with CBNG sources, while the annual impacts are associated with coal-fired power plant emissions. Based on the modeling results, coal mining would not contribute substantially to SO_2 impacts. The 3-hour SO_2 impacts are predicted to increase by up to a factor of 2 relative to the base year, and 24-hour impacts are predicted to increase by 25 percent as a result of CBNG activities affecting the short-term impacts. Annual impacts have only moderate increases (7 to 8 percent) relative to the base year.

3.1.1.2 Impacts at Near-field Receptors in Montana

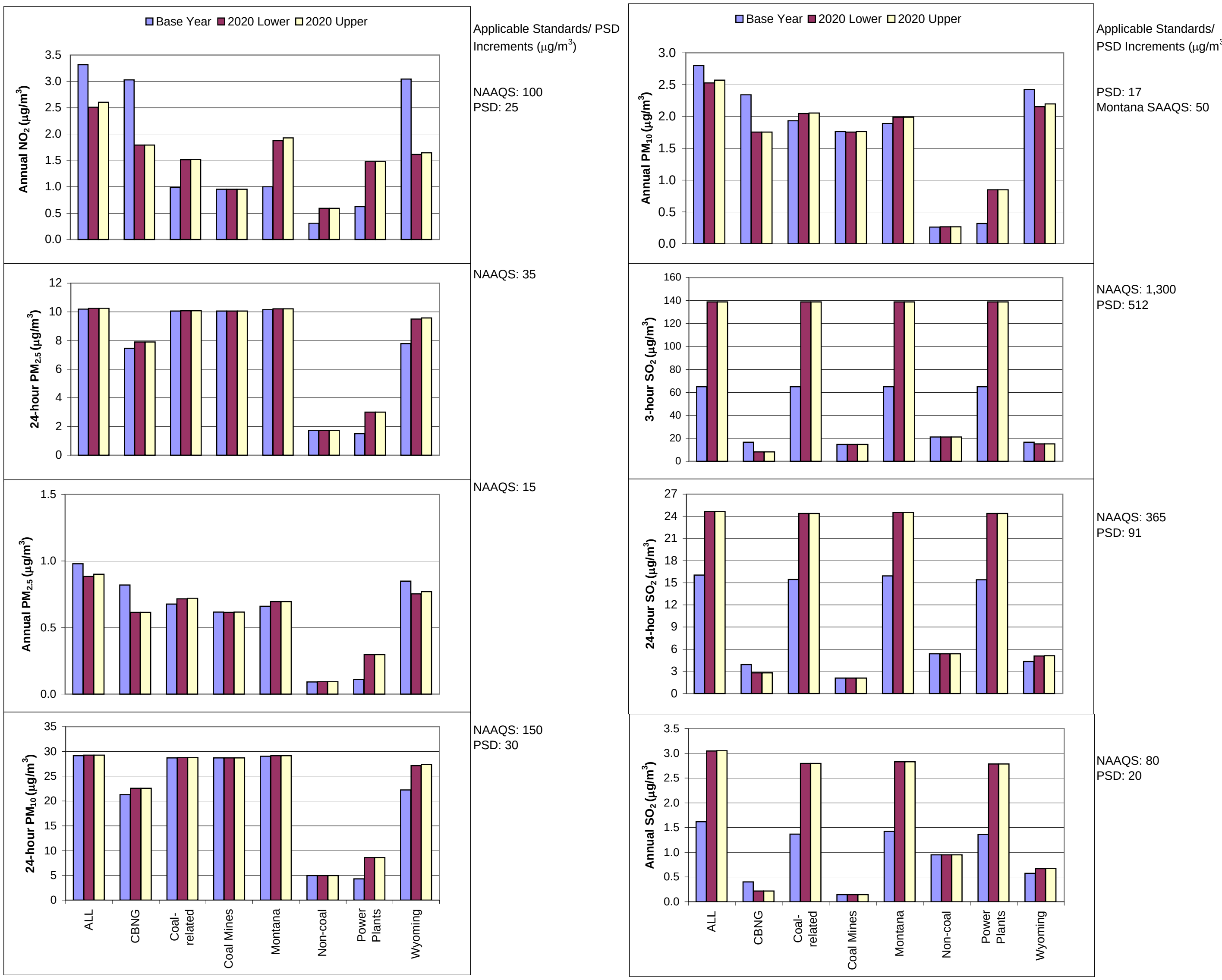
Figure 3-5 provides a similar analysis for near-field receptors in Montana, providing the maximum modeled impact for each source group as well as the total predicted maximum. The modeled impacts and a comparison to the 1-hour Montana standards for SO_2 and NO_2 are provided in **Figure 3-6**. Projected impacts are all well below the state and national standards. Notably, future year impacts of NO_2, PM_{10}, and $PM_{2.5}$ are predicted to either remain similar to the base year or decrease. Reductions in impacts are due to the anticipated southerly progression of Wyoming CBNG wells, which previously were impacting areas in Montana.

As shown in **Figures 3-2, 3-3**, and **3-4**, the modeled PM_{10} and $PM_{2.5}$ impacts in the Montana near-field are substantially less than those modeled for the Wyoming near-field. The annual and 24-hour impacts of PM_{10} and $PM_{2.5}$ emissions remained below applicable standards and the PSD increments, except for the 24-hour PM_{10} impacts, which remain just below the PSD increment in future year scenarios. No formal increment consumption analysis was completed; therefore, this comparison is not a valid PSD increment consumption evaluation.

Based on the modeling results, the annual and 1-hour NO_2 impacts in Montana would be well below the ambient standard. This is a marked improvement in the 1-hour NO_2 impacts relative to the projected impacts for 2015, where it was predicted that the 1-hour NO_2 standard would be exceeded under the 2015 upper and lower development scenarios. The modeling for 2020 suggests that as Wyoming CBNG wells move southward, short-term 1-hour NO_2 impacts in Montana would remain below the standard. The primary contributor to the maximum short-term NO_2 impacts appear to be due to projected increases in Montana CBNG production. An acceptable adjustment of 0.75 was used to convert the NO_x emissions to NO_2 impacts.

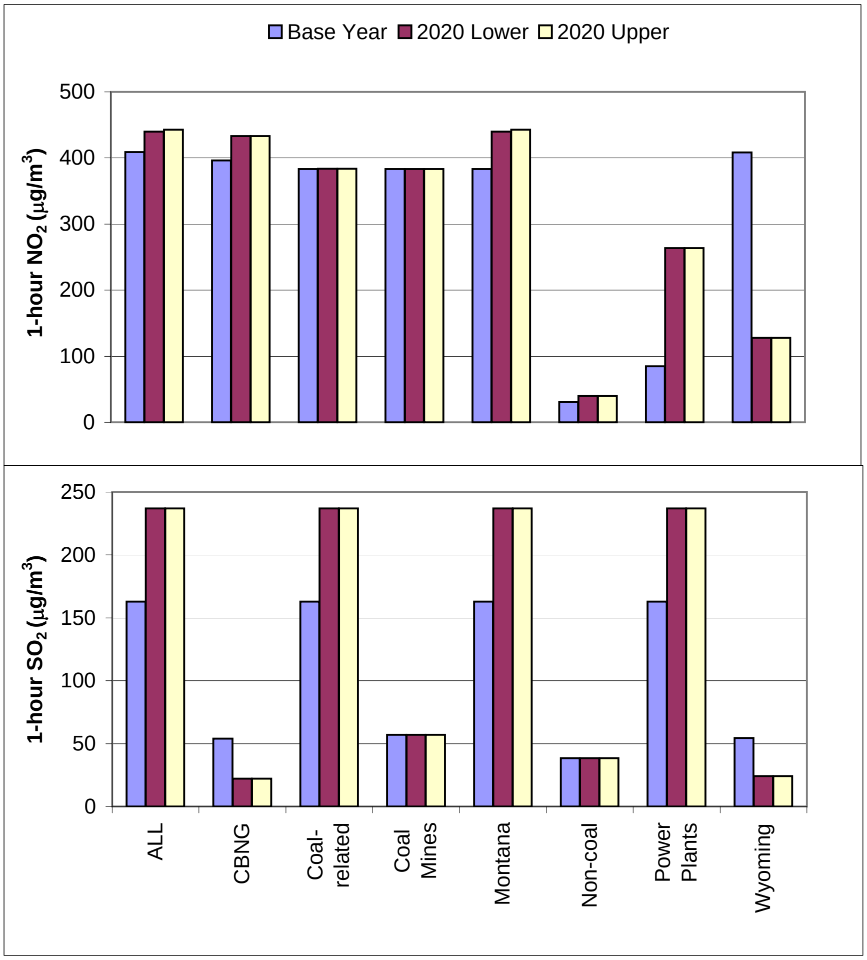
Based on the modeling, the SO_2 impacts in Montana would be well below the applicable standards and PSD increment levels. The projected maximum impacts from SO_2 emissions are attributable to emissions from Montana coal-fired power plant sources. The modeled impacts showed that increases of SO_2 impacts are predicted to approximately double for all averaging periods, resulting largely from additional coal-fired power plants.

Figure 3-5
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$
at Montana Near-field Receptors



Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

Figure 3-6
Change in Modeled Concentrations of 1-hour NO_2 and SO_2
at Montana Near-field Receptors



Applicable Standards/
Montana Standards ($\mu g/m^3$)

Montana SAAQS: 564

Montana SAAQS: 1,300

Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

3.1.2 Air Quality Impacts at Class I Area Receptors

As discussed in Chapter 2.0, the impacts at Class I areas also were modeled, with separate assessments for each Class I receptor group. The modeled impacts were all well below the ambient standards for all air pollutants. For comparison only, the 24-hour PM_{10} impacts were above the Class I PSD increment levels for the base and future year scenarios at the Northern Cheyenne Indian Reservation (IR), Badlands NP, and Wind Cave NP. The Class I areas with the highest SO_2 impacts were Theodore Roosevelt NP, the Northern Cheyenne IR, and Fort Peck IR. The majority of the SO_2 impacts in Theodore Roosevelt NP and Fort Peck IR occur in the base year and are not indicative of growth in the PRB region.

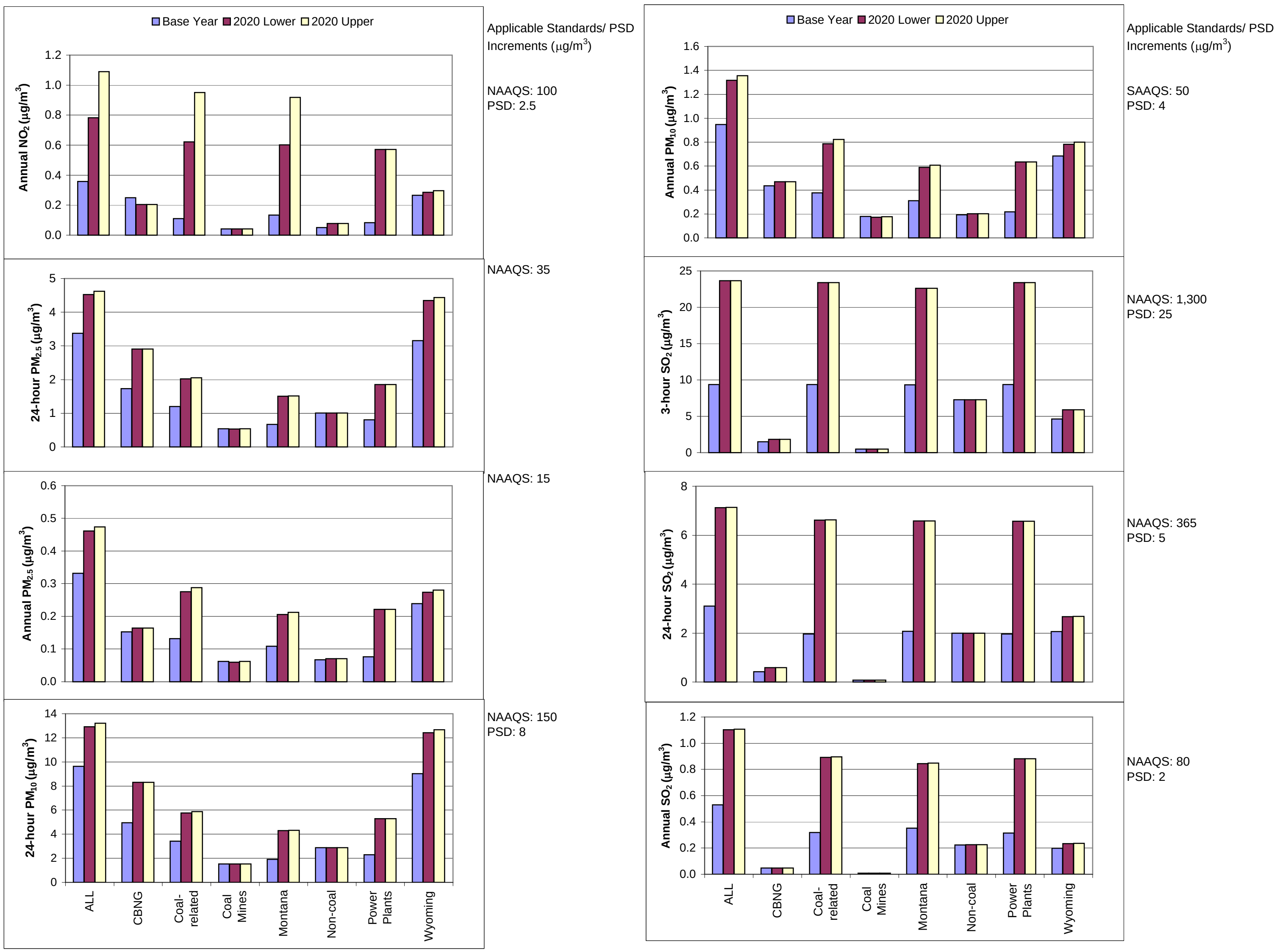
The results for the Northern Cheyenne IR are provided in **Figure 3-7**. The modeled impacts were all well below the ambient standards and the PSD increments for all air pollutants, except the projected impacts are above the 24-hour PM_{10} and SO_2 increment levels. For comparison only, the 24-hour PM_{10} impacts were above the Class I PSD increments for the base year and future year scenarios. The 24-hour PM_{10} impacts are predicted to increase by up to 40 percent from the base year to the future year scenarios, primarily as a result of increases in Wyoming sources (predominantly CBNG development). For comparison only, the 24-hour SO_2 impacts were above the Class I PSD increment levels, primarily as a result of additional coal-fired power plants in Montana. All other SO_2 and NO_2 impacts are less than 5 percent of the national and state standards.

Two additional Class I areas also were analyzed, including Badlands NP (**Figure 3-8**) and Wind Cave NP (**Figure 3-9**). These areas show modeled impacts above the comparative Class I PSD increment levels for 24-hour PM_{10} for the future year development scenarios. The PM_{10} impacts at the Badlands NP are slightly over comparative 24-hour Class I PSD increment but remain below 25 percent of the annual standard. The base year (2004) 24-hour PM_{10} impact at Wind Cave NP was 10.8 $\mu g/m^3$, and the upper production scenario was 13.3 $\mu g/m^3$, versus a Class I PSD increment level of 8 $\mu g/m^3$. For both areas, all modeled SO_2 and NO_2 impacts are near or less than 1 percent of the ambient standards, and also are below their comparative PSD increment levels. The 24-hour SO_2 combined impacts are between 80 to 95 percent of the comparable PSD increments.

The predicted 24-hour SO_2 impacts at Theodore Roosevelt NP and Fort Peck IR, and the 3-hour SO_2 impacts at Theodore Roosevelt NP; exceeded the Class I PSD increments; these predicted exceedances are due to sources outside of the PRB study area. The predicted 24-hour SO_2 impacts exceed the Class I PSD increments at Northern Cheyenne IR due to the addition of coal-fired power plants in Montana. The maximum modeled impacts are less than 5 percent of the national and state standards for all pollutants at Theodore Roosevelt NP, the Northern Cheyenne IR, and Fort Peck IR.

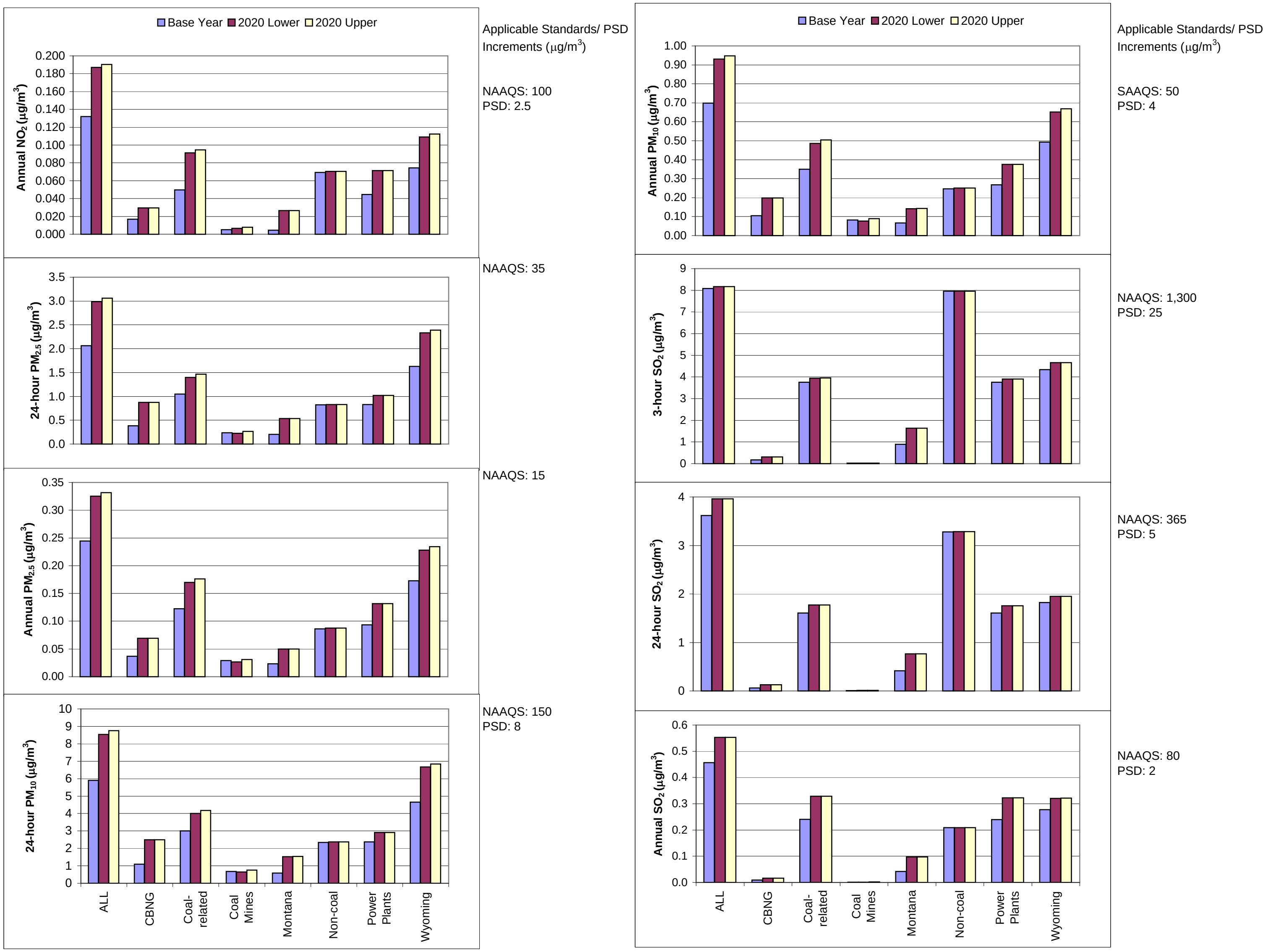
These impact data are provided for comparison only; PSD increment-consuming sources were not specifically evaluated.

Figure 3-7
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$ at Northern Cheyenne IR



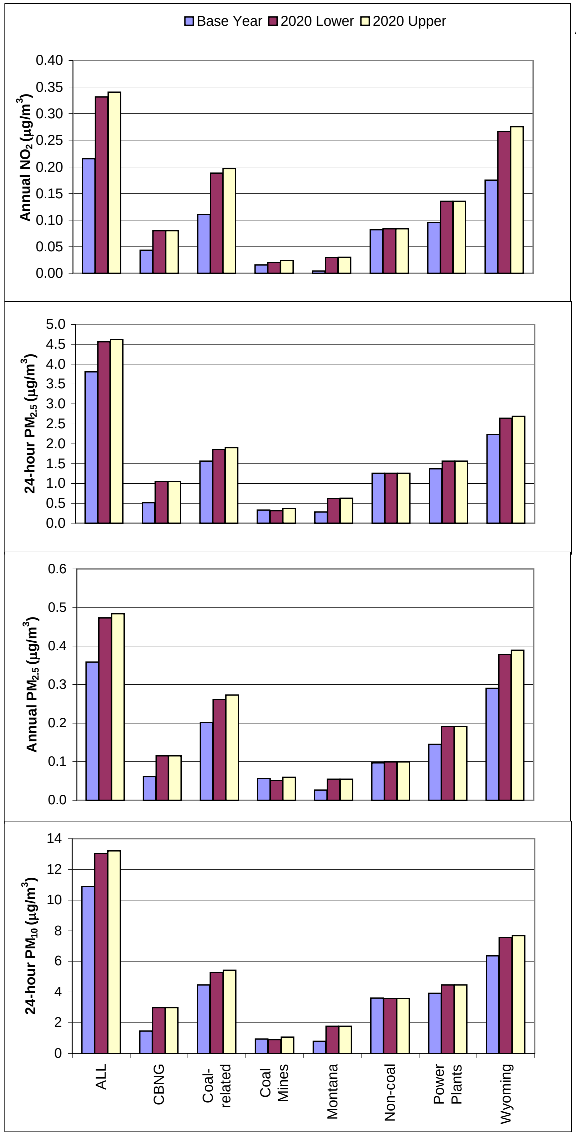
Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

Figure 3-8
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$
at Badlands NP



Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

Figure 3-9
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$ at Wind Cave NP



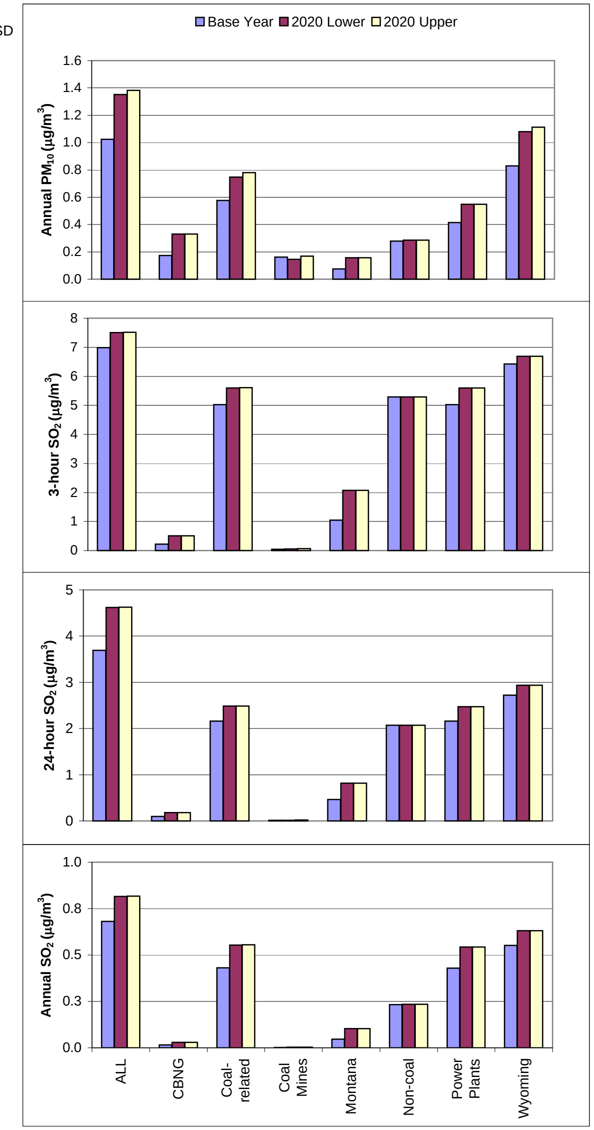
Applicable Standards/ PSD Increments (µg/m^3)

NAAQS: 100
PSD: 2.5

NAAQS: 35

NAAQS: 15

NAAQS: 150
PSD: 8



Applicable Standards/ PSD Increments (µg/m^3)

SAAQS: 50
PSD: 4

NAAQS: 1,300
PSD: 25

NAAQS: 365
PSD: 5

NAAQS: 80
PSD: 2

Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

3.1.3 Air Quality Impacts at Sensitive Class II Area Receptors

None of the Sensitive Class II areas evaluated for this study had predicted impacts that exceeded the ambient standards or Class II PSD increment thresholds. Modeled impacts at the Cloud Peak Wilderness Area (WA) and Crow IR demonstrated the largest changes in NO_2 impacts with respect to the base year. For PM_{10} impacts, the highest changes relative to the base year occurred at the Wind River IR. Modeled impacts for Cloud Peak Wilderness Area (WA) and Crow IR are shown in **Figure 3-10** and **Figure 3-11**, respectively. For the two Class II areas, modeled impacts were below the ambient standards, and they were below established Class II PSD increment levels. At the Cloud Peak WA, there was a marked change in NO_2 and PM_{10} impacts due to increased CBNG production shifting toward the WA. Similarly, at the Crow IR, the modeled NO_2 impacts demonstrate a marked increase due to projected coal-related RFD sources under the 2020 upper and lower development scenarios.

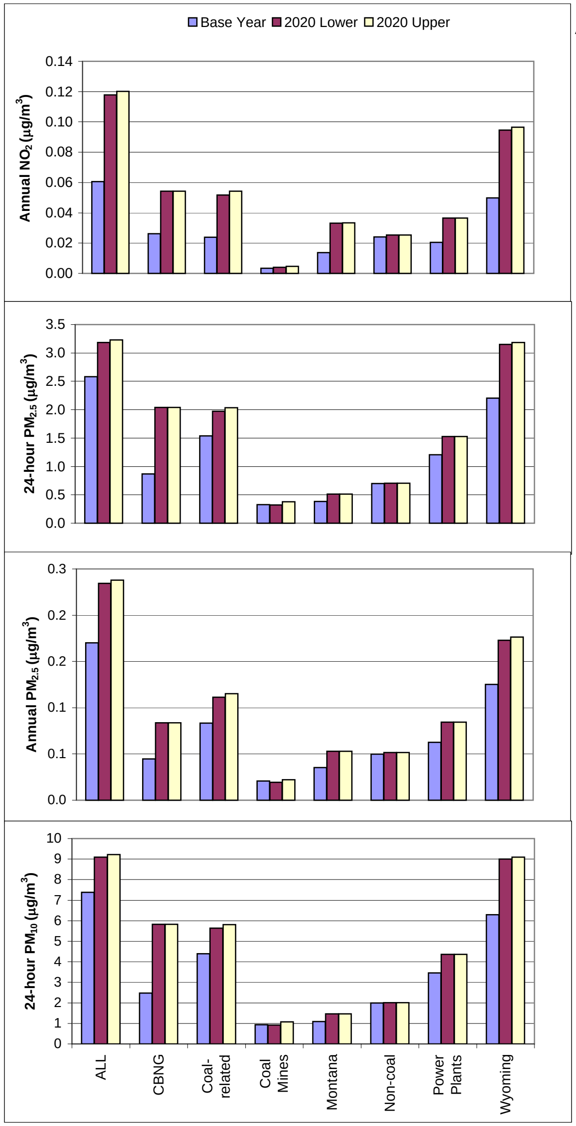
Figure 3-12 shows the base year (2004) and predicted future year (2020) modeled 1-hour NO_2 impacts at Big Horn Canyon National Recreation Area (NRA) and Crow IR. These two Class II areas have the highest modeled impacts of any modeled Class II area for the base year, yet impacts in the future years remain below the state 1-hour standard of 564 $\mu g/m^3$. It is likely that the conservative modeled impacts are greater than actual impacts. Initially, nitrogen monoxide (NO) emissions comprise the majority of NO_x emissions. NO is then converted into NO_2. Given that the conversion of NO into NO_2 typically occurs over several hours (Finlayson-Pitts and Pitts 2000), the fraction of NO_x that is NO_2 is probably substantially less than the 75 percent assumed for this study over the 1-hour averaging period.

3.1.4 Impacts on Visibility

Under the Clean Air Act, visibility has been established as a critical resource for identified Class I areas. Under the guidance of the Federal Land Managers Air Quality Workgroup (FLAG) (FLAG 2000), the impacts presented here were calculated using the same approach presented in the Task 1A and original Task 3A reports. The visibility impacts are provided using the CALPUFF modeling system and the Method 6 approach, which uses monthly relative humidity values for representative receptor groups. Visibility impacts were based on the highest 24-hour calculated extinction (reduced visibility) at the indicated source receptors. Impacts were based on FLAG speciated seasonal natural background reference visibility levels and calculated as a percent increase in extinction from the background values. Visibility impacts also can be expressed in terms of deciviews (dv), a measure for describing perceived changes in visibility. One deciview is defined as a change in visibility that is just perceptible to the average person. The study tabulated the reduced visibility at the maximum impact receptor in each of the Class I and Class II groups in terms of the maximum reduction on any one 24-hour period, the number of days annually that showed visibility reductions of 5 percent and 10 percent, which are equivalent to reductions in deciviews of 0.5 and 1 deciview, respectively. A significance threshold of 10 percent (1 deciview) has been used in this analysis to evaluate the frequency of the impact from the source groups.

Tables 3-2 and **3-3** provide the modeled visibility impact results using “Method 6” for the lower and upper production scenarios for 2020, respectively. Based on the modeling results, those areas predicted to be the most impacted in the base year (2004) and 2015 typically are predicted to

Figure 3-10
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$
at Cloud Peak WA



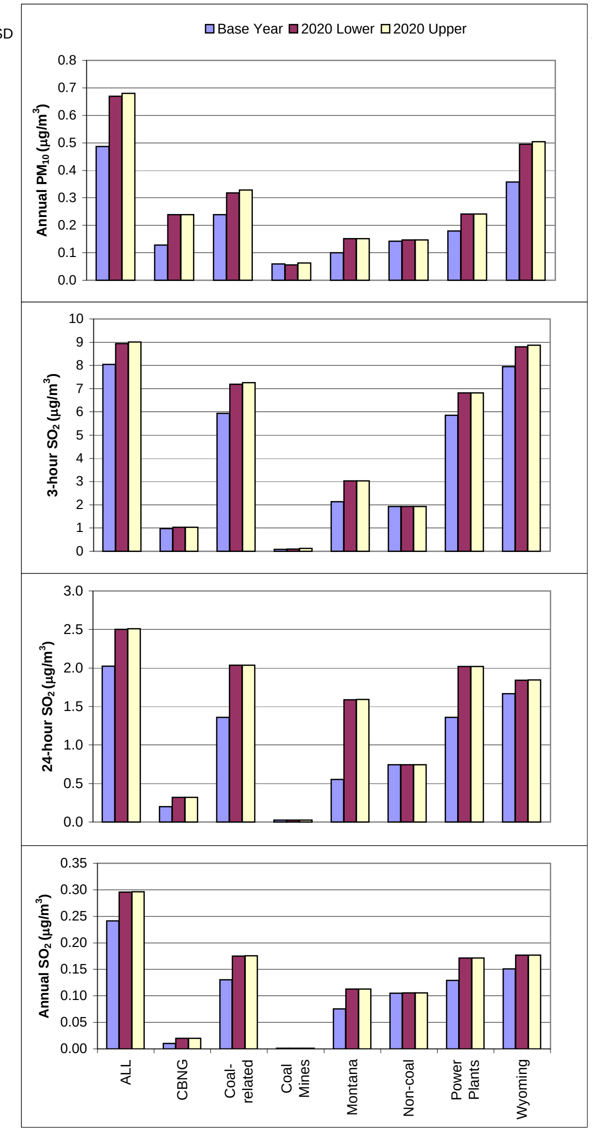
Applicable Standards/ PSD Increments ($\mu g/m^3$)

NAAQS: 100
PSD: 25

NAAQS: 35

NAAQS: 15

NAAQS: 150
PSD: 30



Applicable Standards/ PSD Increments ($\mu g/m^3$)

SAAQS: 50
PSD: 17

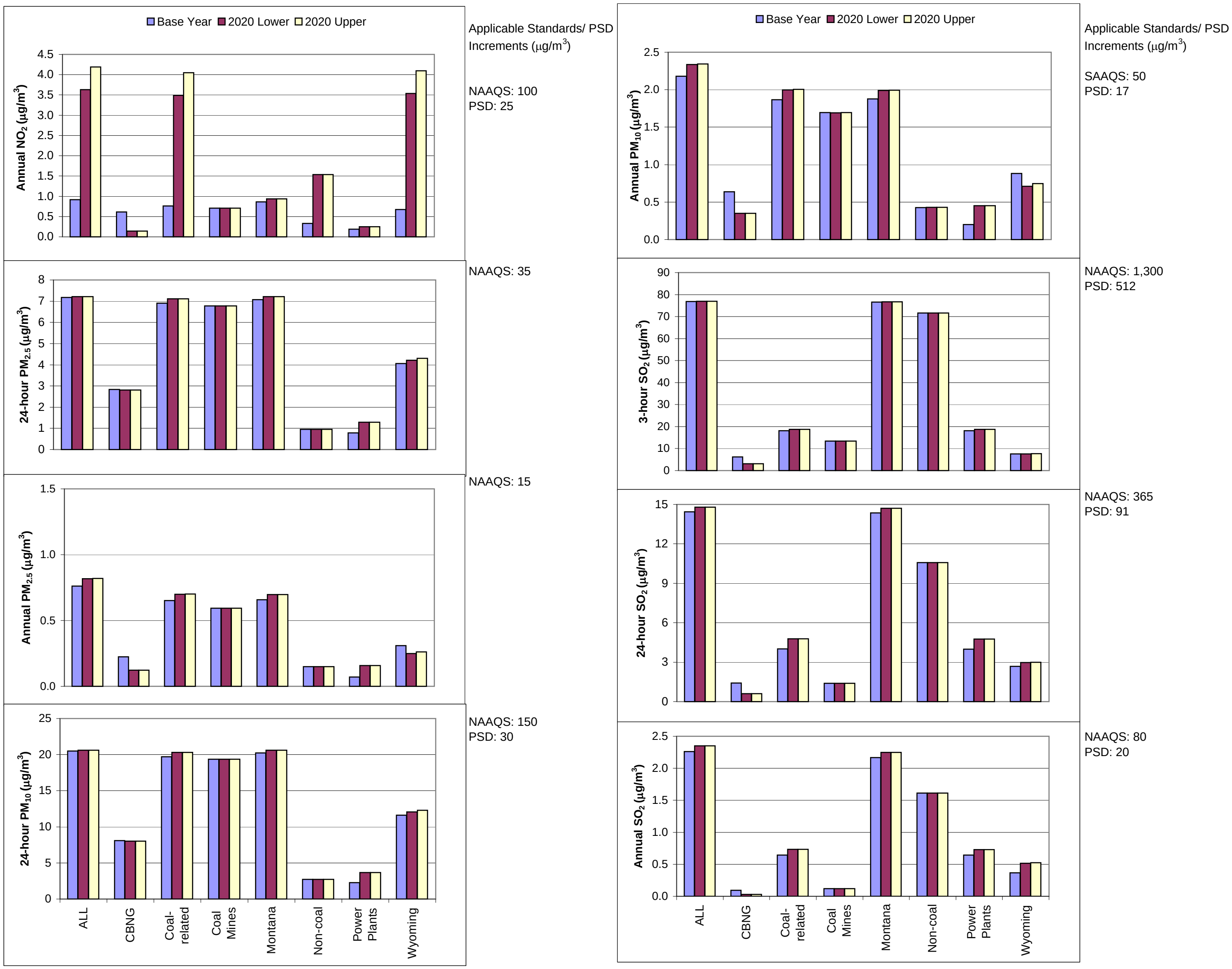
NAAQS: 1,300
PSD: 512

NAAQS: 365
PSD: 91

NAAQS: 80
PSD: 20

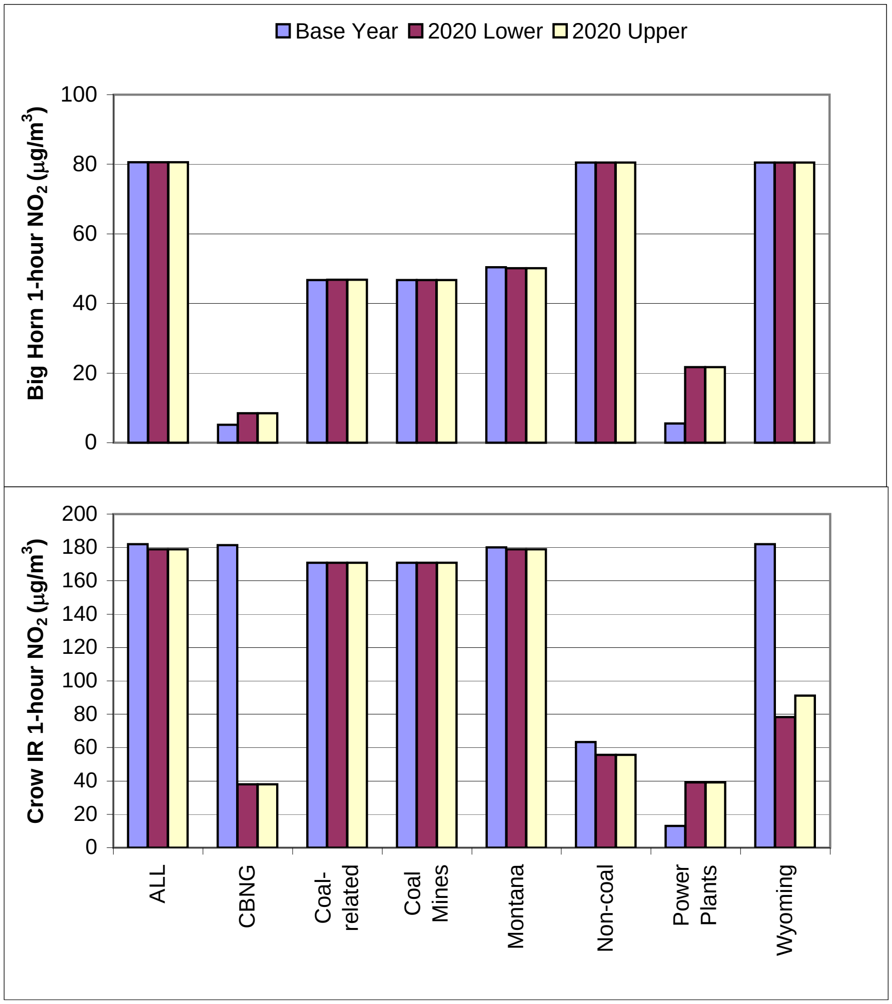
Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

Figure 3-11
Change in Modeled Concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$
at Crow IR



Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

Figure 3-12
Change in Modeled Concentrations of 1-Hour NO_2
at Big Horn Canyon NRA and Crow IR



Applicable Standards/ Montana Standards (μg/m^3)

Montana SAAQS: 564

Montana SAAQS: 564

Note:
Base Year = 2004
2020 Lower = 2020 lower production scenario
2020 Upper = 2020 upper production scenario

Table 3-2
Modeled Visibility Impacts for the 2020 Lower Production Scenario[1]

Receptor Set	All Sources			CBNG			Coal-related Sources			Coal Mines			Montana Sources			Non-coal Sources			Power Plants			Wyoming Sources		
	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}
	5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%	
CLASS I AREAS																								
Badlands NP	297	262	390	124	66	101	247	186	215	19	3	15	126	76	72	179	98	286	232	164	199	234	187	261
Bob Marshall WA	21	8	73	0	0	1	12	6	53	0	0	0	14	7	60	4	2	65	12	6	53	2	0	9
Bridger WA	215	149	154	19	13	58	144	88	64	0	0	3	44	23	44	163	91	122	141	85	64	179	125	123
Fitzpatrick WA	159	97	125	13	6	23	101	50	82	0	0	2	41	22	56	97	49	79	101	49	79	124	74	98
Fort Peck IR	167	125	257	28	16	92	123	80	84	12	2	12	108	60	89	96	56	252	114	72	66	72	51	156
Gates of the Mountain WA	95	59	118	0	0	3	79	38	102	0	0	1	88	48	117	39	11	43	78	38	102	7	3	19
Grand Teton NP	135	76	88	3	1	13	76	36	51	0	0	3	34	18	32	78	34	75	74	36	48	66	37	65
North Absaorka WA	136	69	234	7	3	19	91	43	157	0	0	2	88	45	126	52	20	70	90	41	152	53	24	91
North Cheyenne IR	350	302	544	158	113	257	322	258	352	67	15	26	338	272	161	150	61	282	300	240	323	168	131	517
Red Rock Lakes	83	45	65	2	0	9	53	28	63	0	0	2	44	20	64	36	10	30	53	28	63	26	14	39
Scapegoat WA	49	29	74	0	0	2	38	20	58	0	0	0	42	25	66	13	3	57	37	20	58	5	3	15
Teton WA	128	65	155	8	2	13	78	39	107	0	0	2	49	27	72	62	23	44	76	38	103	65	34	92
Theodore Roosevelt NP	253	202	307	57	36	79	148	96	156	5	0	9	113	73	130	182	112	298	140	85	138	114	80	187
U.L. Bend WA	143	95	228	18	8	60	116	65	138	5	0	10	115	63	119	53	28	205	107	61	125	43	27	97
Washakie WA	153	91	235	14	3	45	105	49	148	0	0	3	81	39	127	74	33	81	104	48	146	86	52	152
Wind Cave NP	334	290	559	158	99	112	301	243	368	49	12	17	144	70	85	180	98	338	283	203	325	292	246	467
Yellowstone NP	164	89	196	8	3	14	111	59	137	0	0	3	93	53	102	79	26	54	111	59	132	55	34	74
SENSITIVE CLASS II AREAS																								
Absaorka Beartooth WA	196	111	225	7	3	16	151	81	155	0	0	3	164	89	120	71	34	64	149	79	151	44	21	104
Agate Fossil Beds NM	322	277	676	119	68	182	289	228	499	33	8	27	99	52	45	166	84	178	276	208	427	309	258	642
Big Horn Canyon NRA	361	332	449	42	26	116	220	137	307	86	60	224	218	149	241	355	295	161	191	105	224	348	295	329
Black Elk WA	327	283	523	135	69	84	280	210	281	22	5	15	139	64	92	178	97	366	267	181	249	271	224	351
Cloud Peak WA	227	155	713	72	46	373	160	103	603	10	5	83	121	65	74	103	45	142	150	97	458	150	100	713
Crow IR	364	363	652	134	99	284	364	358	559	364	340	504	364	361	545	292	139	133	287	203	433	316	211	648
Devils Tower NM	341	305	325	196	141	108	313	261	227	69	15	23	167	86	79	150	77	194	294	217	191	295	252	290
Fort Belknap IR	127	80	205	12	6	40	102	58	136	3	0	7	105	56	123	43	22	151	97	52	125	31	22	72
Fort Laramie NHS	318	275	740	102	63	270	290	221	623	22	8	42	88	37	77	166	79	238	281	199	518	310	262	744
Jedediah Smith WA	142	82	113	3	1	13	74	36	55	0	0	3	34	15	34	98	45	100	71	36	55	61	39	81
Jewel Cave NM	335	297	532	160	96	116	308	247	326	55	9	26	131	61	105	161	86	288	286	201	281	292	256	428
Lee Metcalf WA	171	99	145	2	1	13	138	78	105	0	0	1	140	81	93	56	17	36	137	78	103	27	13	49
Mt Naomi WA	90	52	239	5	3	20	51	33	204	0	0	2	5	1	17	62	29	81	49	31	204	61	39	229
Mt Rushmore NM	320	271	522	131	59	76	271	192	260	20	5	12	133	60	83	159	83	368	248	172	231	261	209	320
Popo Agie WA	206	145	162	23	16	89	128	77	69	0	0	4	41	24	53	142	72	68	126	75	66	167	115	119
Soldier Creek WA	324	287	652	136	86	169	306	244	511	42	16	26	114	61	61	178	86	180	298	221	451	312	265	606
Wellsville Mountain WA	221	147	295	49	30	154	129	75	156	3	1	12	80	48	123	136	77	126	127	72	146	158	107	237
Wind River IR	281	226	342	69	45	179	187	120	238	6	1	12	90	53	142	257	153	162	180	115	235	262	197	302

[1] Visibility - Method 6 and monthly f(Rh) values.

Note:
N = N percent (5 or 10 percent as indicated).
B_{ext} = extinction coefficient for visibility.

Table 3-3
Modeled Visibility Impacts for the 2020 Upper Production Scenario[1]

Receptor Set	All Sources			CBNG			Coal-related Sources			Coal Mines			Montana Sources			Non-coal Sources			Power Plants			Wyoming Sources		
	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}	Number of Days > N% Change in B_{ext}		Maximum % Change in B_{ext}
	5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%	
CLASS I AREAS																								
Badlands NP	297	262	393	124	66	101	247	189	221	24	5	17	129	79	75	179	98	286	235	166	203	234	189	266
Bob Marshall WA	21	8	73	0	0	1	12	6	53	0	0	0	15	7	60	4	2	65	12	6	53	2	0	10
Bridger WA	215	149	154	19	13	58	145	90	66	0	0	4	44	23	45	163	91	122	143	86	64	179	125	123
Fitzpatrick WA	161	97	126	13	6	23	101	51	84	0	0	2	41	22	58	97	49	79	101	49	80	124	74	98
Fort Peck IR	167	126	257	28	16	92	124	82	92	13	2	13	110	62	91	96	56	252	115	75	67	73	52	159
Gates of the Mountain WA	95	59	118	0	0	3	79	38	102	0	0	1	89	48	117	39	11	43	79	38	102	7	3	19
Grand Teton NP	135	76	88	3	1	13	76	36	52	0	0	3	34	18	32	78	34	75	75	36	49	66	37	65
North Absaorka WA	137	69	237	7	3	19	91	43	160	0	0	2	89	46	129	52	20	70	90	41	155	53	24	92
North Cheyenne IR	355	303	550	158	113	257	330	267	360	74	20	29	342	283	171	150	61	282	306	252	325	169	132	521
Red Rock Lakes	83	45	65	2	0	9	53	28	63	0	0	2	44	20	64	36	10	30	53	28	63	26	14	39
Scapegoat WA	49	29	75	0	0	2	38	20	58	0	0	1	42	25	66	13	3	57	38	20	58	5	3	15
Teton WA	128	65	157	8	2	13	78	39	109	0	0	2	50	27	74	62	23	44	76	38	105	66	34	92
Theodore Roosevelt NP	253	202	308	57	36	79	152	99	167	7	1	11	116	74	138	182	112	298	145	88	146	114	81	190
U.L. Bend WA	144	95	237	18	8	60	118	67	146	6	1	11	118	65	126	53	28	205	109	61	132	43	27	99
Washakie WA	153	91	239	14	3	45	105	49	149	0	0	3	81	40	129	74	33	81	104	49	147	86	52	153
Wind Cave NP	334	293	564	158	99	112	304	248	383	56	18	20	149	73	89	180	98	338	287	205	332	292	247	472
Yellowstone NP	164	89	199	8	3	14	111	60	139	0	0	3	93	53	104	79	26	54	111	59	134	55	34	75
SENSITIVE CLASS II AREAS																								
Absaorka Beartooth WA	196	111	228	7	3	16	152	81	159	0	0	3	164	89	123	71	34	64	150	79	153	44	21	105
Agate Fossil Beds NM	322	277	680	119	68	182	290	230	516	40	12	31	101	52	50	166	84	178	276	209	432	310	260	646
Big Horn Canyon NRA	361	332	458	42	26	116	221	141	315	86	60	224	218	149	241	355	295	161	192	109	228	348	296	333
Black Elk WA	328	283	529	135	69	84	285	217	293	26	7	17	145	67	97	178	97	366	267	183	255	273	225	356
Cloud Peak WA	227	156	718	72	46	373	161	106	616	11	6	97	122	66	76	103	45	142	150	97	459	150	100	719
Crow IR	364	363	655	134	99	284	364	358	564	364	340	504	364	361	548	292	139	133	289	206	434	322	225	651
Devils Tower NM	343	306	332	196	141	108	315	269	234	78	21	27	173	95	83	150	77	194	296	220	192	295	253	295
Fort Belknap IR	128	81	213	12	6	40	102	58	144	4	0	8	106	57	130	43	22	151	98	54	131	31	22	73
Fort Laramie NHS	318	276	742	102	63	270	292	224	643	29	9	49	89	41	80	166	79	238	281	201	524	310	264	746
Jedediah Smith WA	142	82	113	3	1	13	74	36	55	0	0	4	34	15	34	98	45	100	71	36	55	61	40	81
Jewel Cave NM	336	298	541	160	96	116	310	249	341	64	17	30	136	63	111	161	86	288	290	202	288	293	258	435
Lee Metcalf WA	172	99	146	2	1	13	138	78	106	0	0	1	141	81	93	56	17	36	137	78	104	27	13	49
Mt Naomi WA	90	52	239	5	3	20	51	33	204	0	0	3	5	1	17	62	29	81	49	31	204	61	39	229
Mt Rushmore NM	322	274	528	131	59	76	274	199	271	23	7	14	138	64	88	159	83	368	249	174	236	263	209	325
Popo Agie WA	206	145	168	23	16	89	128	78	71	0	0	5	43	25	54	142	72	68	126	75	67	167	115	120
Soldier Creek WA	324	287	656	136	86	169	307	249	523	54	19	30	118	61	68	178	86	180	298	221	457	312	267	610
Wellsville Mountain WA	221	147	300	49	30	154	131	75	160	3	1	13	80	48	127	136	77	126	127	72	149	158	108	240
Wind River IR	281	227	343	69	45	179	187	122	240	8	1	13	90	53	145	257	153	162	180	115	236	262	198	302

[1] Visibility - Method 6 and monthly f(Rh) values.

Note:
N = N percent (5 or 10 percent as indicated).
B_{ext} = extinction coefficient for visibility.

continue to be impacted by production increases in 2020. For the Class I areas, the maximum impacts were at the North Cheyenne IR in Montana and at Wind Cave NP and Badlands NP in South Dakota. Both of these South Dakota areas are located adjacent to, and east of, the PRB study area, and are downwind of the prevailing wind direction from the PRB. In the base year (2004), modeling showed more than 200 days would be impacted with a change of 10 percent or more in extinction at each of these Class I areas. This trend continues for 2015 and 2020 projected impacts. Modeling results suggest that by 2020 these three maximum impacted Class I areas may experience change of at least 1.0 dv for more than 300 days a year.

For the Class II areas, the maximum impacts were at the Crow IR and the Big Horn Canyon NRA in Montana, with almost all days in a year impacted by 10 percent or more. Eight other Class II areas showed impacts of 10 percent or more for 200 days or more per year. These areas also are located east (downwind in the prevailing wind direction) of the PRB study area, with the exception of Wind River IR, which is to the west.

The modeling results showed that coal mining and CBNG operations had little to no impact on the visibility to the northwest of the PRB. Power plants and coal mines dominated the impacts at the Class II areas, and the impacts on the Class I areas generally were split between power plants and CBNG operations. Coal mining activities generally had a negligible impact on the visibility at all locations except for areas in close proximity to the PRB (Northern Cheyenne IR, Big Horn Canyon, and Crow IR). However, areas disproportionately impacted by CBNG development are predicted to have larger visibility impairment, relative to other areas, as CBNG development continues to expand. Likewise, areas disproportionately impacted by conventional oil and gas development (represented in the "non-coal" source group) are predicted to have an improved visible range, relative to other areas, as oil- and gas-related emissions are predicted to slow by 2020.

To provide a basis for discussing the modeled visibility impacts resulting from increased production (emissions) under both the lower and upper production scenarios in 2020, the modeled visibility impacts for the base year (2004) (**Table 3-2** in the 2015 Update report) were subtracted from the model results for 2020. The resulting changes in modeled visibility impacts are presented in **Tables 3-4** and **3-5**. The data in these tables show the projected changes in the number of days with impacts greater than 5 and 10 percent, as well as the projected incremental increase in the maximum percent change in light extinction as a result of the RFD activities. It should be noted that for most Class I areas, the model results show no change from the base year in the number of days with impacts greater than 5 percent, although the modeling results indicate that the maximum level of impacts for those days would increase. Concurrently, the model results may show a corresponding increase from the base year in the number of days with impacts above 10 percent. For such data sets, the increase in the number of days with impacts greater than 10 percent does not conflict with the fact that there is no anticipated increase in the number of days with impacts greater than 5 percent, as the data represent the change over base year (2004) conditions.

For all sources combined, the largest impacts (greater than 10 percent for 10 days or more for both production scenarios) would be to those Class I areas estimated to currently be most impacted and generally located adjacent to and to the east of the PRB study area (Northern Cheyenne IR, Badlands NP, and Wind Cave NP).

Table 3-4
Change in Modeled Visibility Impacts - 2020 Lower Production Scenario Less the Base Year (2004)[1]

	All Sources			CBNG			Coal-related Sources			Coal Mines			Montana Sources			Non-coal Sources			Power Plants			Wyoming Sources		
	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}	Change in Number of Days > N% Change in B_{ext}		Change in the Maximum % Change in B_{ext}
Receptor Set	5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%		5%	10%	
CLASS I AREAS																								
Badlands NP	14	44	55	52	41	57	48	58	81	8	0	2	63	52	26	5	1	1	56	43	70	16	31	80
Bob Marshall WA	5	0	2	0	0	0	0	1	1	0	0	0	0	1	1	0	0	0	0	1	1	0	0	0
Bridger WA	3	5	9	10	10	35	8	6	2	0	0	0	11	2	8	1	1	-1	6	5	1	2	7	3
Fitzpatrick WA	2	6	10	8	6	15	6	7	13	0	0	0	6	3	7	2	2	0	10	7	11	4	5	2
Fort Peck IR	16	20	1	10	5	40	30	29	27	0	0	1	32	25	26	0	1	0	32	28	14	4	8	61
Gates of the Mountain WA	5	4	2	0	0	2	7	1	2	0	0	0	5	1	2	0	0	0	6	1	2	0	0	1
Grand Teton NP	3	6	1	2	1	5	8	2	7	0	0	0	4	2	1	0	0	0	7	2	5	1	5	1
North Absaorka WA	5	8	57	5	3	9	10	6	53	0	0	0	12	9	47	0	0	0	9	7	51	7	3	12
North Cheyenne IR	34	59	129	-4	7	58	85	121	64	-3	1	1	95	135	83	16	7	1	103	131	45	-18	-8	119
Red Rock Lakes	2	3	2	2	0	5	3	3	2	0	0	0	4	2	2	0	0	0	3	3	2	1	1	2
Scapegoat WA	5	2	9	0	0	1	4	0	1	0	0	0	3	2	1	0	0	0	3	0	1	0	1	1
Teton WA	3	8	38	6	2	5	10	7	36	0	0	0	7	7	24	0	0	0	11	6	33	8	4	1
Theodore Roosevelt NP	10	24	1	11	14	37	34	36	77	0	0	1	37	35	76	1	1	0	37	31	66	15	7	62
UL Bend WA	15	18	15	10	2	18	28	18	71	0	0	0	31	18	52	0	1	0	24	20	61	3	7	21
Washakie WA	6	8	46	10	2	27	7	12	35	0	0	0	9	7	38	0	0	0	7	13	34	6	8	3
Wind Cave NP	16	28	102	50	50	55	44	71	115	12	2	2	77	40	33	4	3	2	55	53	86	9	28	106
Yellowstone NP	4	5	49	7	3	6	4	8	46	0	0	0	7	6	35	0	0	0	5	9	44	2	4	8
SENSITIVE CLASS II AREAS																								
Absaorka Beartooth WA	6	10	58	5	3	8	15	14	55	0	0	0	5	9	21	2	0	0	13	14	52	5	5	15
Agate Fossil Beds NM	12	26	68	45	29	87	23	37	115	1	4	4	51	30	16	6	2	2	25	39	67	13	23	77
Big Horn Canyon NRA	0	1	100	1	8	43	13	23	59	0	0	0	16	22	0	0	0	0	33	35	45	0	0	73
Black Elk WA	20	47	67	53	39	40	49	58	93	1	3	2	76	38	47	3	1	2	60	45	72	13	38	86
Cloud Peak WA	18	29	35	25	19	62	29	24	112	1	2	9	32	27	22	4	4	20	23	28	42	16	16	38
Crow IR	0	3	55	-17	-19	113	0	6	24	0	0	0	0	5	15	14	7	0	50	70	59	61	32	63
Devils Tower NM	20	31	52	16	46	58	56	76	46	-6	-5	0	91	55	46	10	7	0	70	77	20	1	6	45
Fort Belknap IR	16	14	46	6	2	10	23	22	78	0	0	0	26	18	52	0	1	0	22	18	68	4	8	12
Fort Laramie NHS	5	15	13	37	35	126	14	34	139	1	2	6	48	21	31	8	3	9	20	21	70	4	24	24
Jedediah Smith WA	2	3	1	2	1	5	9	2	1	0	0	0	5	2	1	2	0	0	6	2	1	3	6	1
Jewel Cave NM	24	36	126	52	52	53	50	68	107	3	3	3	71	31	70	5	2	2	61	56	77	4	28	109
Lee Metcalf WA	4	2	64	2	1	10	4	3	52	0	0	0	3	4	29	1	0	0	3	4	51	2	0	5
Mt Naomi WA	2	1	6	4	3	15	4	1	5	0	0	1	1	0	3	0	0	0	2	0	5	2	2	6
Mt Rushmore NM	20	49	67	60	30	38	61	53	88	2	3	1	71	36	40	6	1	2	54	49	69	18	40	79
Popo Agie WA	7	6	48	10	13	57	6	8	15	0	0	0	7	4	15	0	0	0	7	7	12	2	7	29
Soldier Creek WA	3	19	63	38	45	82	24	41	116	4	4	4	55	37	29	9	5	5	32	38	79	8	23	65
Wellsville Mountain WA	12	17	56	30	21	99	10	12	43	0	0	1	11	12	32	1	0	0	11	12	36	9	14	44
Wind River IR	0	9	17	43	28	115	16	15	34	0	0	1	11	10	38	0	0	-1	9	13	33	-1	18	1

[1] Visibility - Method 6 and monthly f(Rh) values.

Note: N = N percent (5 or 10 percent as indicated).
B_{ext} = extinction coefficient for visibility.

Table 3-5
Change in Modeled Visibility Impacts - 2020 Upper Production Scenario Less the Base Year (2004)[1]

Receptor Set	All Sources: Change in Number of Days > N% Change in B_{ext} 5%	All Sources: Change in Number of Days > N% Change in B_{ext} 10%	All Sources: Change in the Maximum % Change in B_{ext}	CBNG: Change in Number of Days > N% Change in B_{ext} 5%	CBNG: 10%	CBNG: Change in the Maximum % Change in B_{ext}	Coal-related Sources: Change in Number of Days > N% Change in B_{ext} 5%	Coal-related Sources: 10%	Coal-related Sources: Change in the Maximum % Change in B_{ext}	Coal Mines: Change in Number of Days > N% Change in B_{ext} 5%	Coal Mines: 10%	Coal Mines: Change in the Maximum % Change in B_{ext}	Montana Sources: Change in Number of Days > N% Change in B_{ext} 5%	Montana Sources: 10%	Montana Sources: Change in the Maximum % Change in B_{ext}	Non-coal Sources: Change in Number of Days > N% Change in B_{ext} 5%	Non-coal Sources: 10%	Non-coal Sources: Change in the Maximum % Change in B_{ext}	Power Plants: Change in Number of Days > N% Change in B_{ext} 5%	Power Plants: 10%	Power Plants: Change in the Maximum % Change in B_{ext}	Wyoming Sources: Change in Number of Days > N% Change in B_{ext} 5%	Wyoming Sources: 10%	Wyoming Sources: Change in the Maximum % Change in B_{ext}
CLASS I AREAS																								
Badlands NP	14	44	59	52	41	57	48	61	87	13	2	4	66	55	28	5	1	1	59	45	74	16	33	85
Bob Marshall WA	5	0	2	0	0	0	0	1	1	0	0	0	1	1	1	0	0	0	0	1	1	0	0	0
Bridger WA	3	5	10	10	10	35	9	8	3	0	0	1	11	2	9	1	1	-1	8	6	1	2	7	3
Fitzpatrick WA	4	6	11	8	6	15	6	8	15	0	0	0	6	3	8	2	2	0	10	7	13	4	5	2
Fort Peck IR	16	21	1	10	5	40	31	31	35	1	0	3	34	27	27	0	1	0	33	31	16	5	9	64
Gates of the Mountain WA	5	4	2	0	0	2	7	1	2	0	0	0	6	1	2	0	0	0	7	1	2	0	0	1
Grand Teton NP	3	6	1	2	1	5	8	2	8	0	0	1	4	2	1	0	0	0	8	2	5	1	5	1
North Absaorka WA	6	8	60	5	3	9	10	6	57	0	0	0	13	10	50	0	0	0	9	7	53	7	3	12
North Cheyenne IR	39	60	135	-4	7	58	93	130	72	4	6	4	99	146	93	16	7	1	109	143	47	-17	-7	123
Red Rock Lakes	2	3	2	2	0	5	3	3	2	0	0	0	4	2	2	0	0	0	3	3	2	1	1	2
Scapegoat WA	5	2	10	0	0	1	4	0	1	0	0	0	3	2	1	0	0	0	4	0	1	0	1	1
Teton WA	3	8	41	6	2	5	10	7	38	0	0	0	8	7	25	0	0	0	11	6	34	9	4	2
Theodore Roosevelt NP	10	24	1	11	14	37	38	39	88	2	1	2	40	36	84	1	1	0	42	34	74	15	8	66
U.L. Bend WA	16	18	24	10	2	18	30	20	80	1	1	1	34	20	60	0	1	0	26	20	68	3	7	23
Washakie WA	6	8	50	10	2	27	7	12	36	0	0	0	9	8	41	0	0	0	7	14	35	6	8	3
Wind Cave NP	16	31	106	50	50	55	47	76	129	19	8	5	82	43	37	4	3	2	59	55	94	9	29	111
Yellowstone NP	4	5	51	7	3	6	4	9	49	0	0	1	7	6	37	0	0	0	5	9	46	2	4	9
SENSITIVE CLASS II AREAS																								
Absaorka Beartooth WA	6	10	61	5	3	8	16	14	58	0	0	0	5	9	23	2	0	0	14	14	55	5	5	16
Agate Fossil Beds NM	12	26	72	45	29	87	24	39	132	8	8	8	53	30	21	6	2	2	25	40	72	14	25	81
Big Horn Canyon NRA	0	1	108	1	8	43	14	27	68	0	0	0	16	22	0	0	0	0	34	39	49	0	1	76
Black Elk WA	21	47	72	53	39	40	54	65	104	5	5	4	82	41	53	3	1	2	60	47	78	15	39	91
Cloud Peak WA	18	30	40	25	19	62	30	27	126	2	3	23	33	28	25	4	4	20	23	28	42	16	16	43
Crow IR	0	3	58	-17	-19	113	0	6	29	0	0	0	0	5	18	14	7	0	52	73	60	67	46	66
Devils Tower NM	22	32	59	16	46	58	58	84	53	3	1	4	97	64	49	10	7	0	72	80	21	1	7	51
Fort Belknap IR	17	15	53	6	2	10	23	22	86	1	0	1	27	19	58	0	1	0	23	20	74	4	8	13
Fort Laramie NHS	5	16	15	37	35	126	16	37	159	8	3	13	49	25	35	8	3	9	20	23	76	4	26	27
Jedediah Smith WA	2	3	1	2	1	5	9	2	1	0	0	1	5	2	1	2	0	0	6	2	1	3	7	1
Jewel Cave NM	25	37	135	52	52	53	52	70	121	12	11	7	76	33	76	5	2	2	65	57	84	5	30	116
Lee Metcalf WA	5	2	65	2	1	10	4	3	53	0	0	0	4	4	30	1	0	0	3	4	51	2	0	5
Mt Naomi WA	2	1	6	4	3	15	4	1	5	0	0	1	1	0	3	0	0	0	2	0	5	2	2	6
Mt Rushmore NM	22	52	72	60	30	38	64	60	98	5	5	3	76	40	44	6	1	2	55	51	74	20	40	83
Popo Agie WA	7	6	53	10	13	57	6	9	17	0	0	1	9	5	16	0	0	0	7	7	13	2	7	29
Soldier Creek WA	3	19	67	38	45	82	25	46	129	16	7	8	59	37	36	9	5	5	32	38	85	8	25	68
Wellsville Mountain WA	12	17	60	30	21	99	12	12	48	0	0	3	11	12	36	1	0	0	11	12	39	9	15	48
Wind River IR	0	10	17	43	28	115	16	17	36	2	0	3	11	10	41	0	0	-1	9	13	35	-1	19	2

[1] Visibility - Method 6 and monthly f(Rh) values.

Note: _N = N percent (5 or 10 percent as indicated).
B_{ext} = extinction coefficient for visibility.

A similar pattern of higher impacts to the east and near the PRB also was observed for the Class II receptor groups. The number of days with 10 percent impact or more would exceed 200 days per year for 10 Class II receptor areas under both the 2020 lower and upper production scenarios. Based on the modeling results, areas to the west of the PRB study area show a distinctly lower impact than those to the east of the PRB study area for both of the 2020 production scenarios. Modeling results show that all areas would experience some increase in visibility impacts.

3.1.5 Impacts on Acid Deposition

Emissions of NO_x and SO_2 could lead to increasing impacts of acidic deposition in the region. This study evaluated the potential increase in acid deposition as a result of the projected increase in production activity in the PRB. The base year (2004) analysis showed that impacts for all listed Class I and Class II areas would be below the established level of concern for sulfur and nitrogen deposition, which are 5 kilograms per hectare per year (kg/ha/yr) for sulfur compounds and 1.5 kg/ha/yr for nitrogen compounds. The FS does not believe these thresholds (shown in **Tables 3-6** and **3-7**) are sufficiently protective; however, until newer thresholds are established, these values are used for comparative purposes. **Tables 3-6** and **3-7** provide a summary of deposition levels for the 2020 lower and upper production scenarios, respectively, at the sensitive receptor areas. The highest modeled impacts are at the Northern Cheyenne IR with nitrogen and sulfur deposition reaching approximately 58 and 21 percent of the level of concern, respectively, due to the proximity of major coal-fired power plant units. Generally, sulfur deposition was greater than nitrogen deposition at the Class I areas analyzed. Contrary to base year impacts, there appears to be a spatial relationship to deposition rates, which generally is lower at the areas to the west of the PRB and higher toward the east. This spatial pattern is representative of the increasing density of emissions sources coupled with the prevailing wind direction.

The modeled changes in acid deposition (future year deposition minus base year deposition in kg/ha/yr) under the lower and upper production scenarios for 2020 are shown in **Tables 3-8** and **3-9**, respectively. The modeled changes in deposition levels for all receptors and for both sulfur and nitrogen compounds show a nominal change in deposition rates, with changes of less than 30 percent of the levels of concern. Similar to visibility impacts, the maximum changes in deposition levels occur in areas already most impacted in the base year. The maximum change in deposition levels occurs at the Northern Cheyenne IR and is predicted to be a result of additional coal-fired power plants rather than CBNG development, which caused the highest impacts to the Northern Cheyenne IR in the 2015 Update. The Northern Cheyenne IR impacts due to CBNG are predicted to decrease in 2020 as the Wyoming well locations are developed farther south.

3.1.6 Impacts on Sensitive Lake Acid Neutralizing Capacity

The analysis of impacts of deposition of acidic substances was carried out in accordance with the screening methodology as provided by the FS (FS 2000). Data for lake neutralizing capacity were obtained from the FS web site (FS 2006), which provides data for the 10^{th} percentile acid neutralizing capacity (ANC) values for the individual lakes that were evaluated. The threshold is intended to account for sensitive conditions that may occur with an episodic or seasonal basis. Input data to the analysis include the deposition rates that were modeled for the base year (2004), and under the lower and upper production scenarios for 2020.

Table 3-6
Modeled Deposition of Nitrogen and Sulfur - 2020 Lower Production Scenario

Receptor Set	POLLUTANT	Maximum Deposition (kg/ha/yr)								Level of Concern (kg/ha/yr)
		ALL Sources	*CBNG*	*Coal-related Sources*	*Coal Mines*	*Montana Sources*	*Non-coal Sources*	*Power Plants*	*Wyoming Sources*	
CLASS I AREAS										
Badlands NP	Nitrogen	0.170	0.024	0.086	0.004	0.032	0.063	0.075	0.097	1.5
	Sulfur	0.229	0.006	0.125	0.001	0.041	0.100	0.123	0.121	5.0
Bob Marshall WA	Nitrogen	0.006	0.000	0.004	0.000	0.004	0.002	0.004	0.002	1.5
	Sulfur	0.010	0.000	0.005	0.000	0.006	0.005	0.005	0.002	5.0
Bridger WA	Nitrogen	0.164	0.007	0.068	0.000	0.012	0.090	0.067	0.148	1.5
	Sulfur	0.206	0.002	0.106	0.000	0.015	0.099	0.106	0.161	5.0
Fitzpatrick WA	Nitrogen	0.211	0.004	0.048	0.000	0.012	0.169	0.047	0.196	1.5
	Sulfur	0.141	0.001	0.077	0.000	0.016	0.081	0.077	0.108	5.0
Fort Peck IR	Nitrogen	0.089	0.009	0.035	0.002	0.028	0.046	0.031	0.029	1.5
	Sulfur	0.139	0.002	0.049	0.000	0.040	0.088	0.048	0.030	5.0
Gates of the Mountain WA	Nitrogen	0.072	0.001	0.049	0.000	0.063	0.022	0.049	0.006	1.5
	Sulfur	0.080	0.000	0.060	0.000	0.067	0.019	0.060	0.006	5.0
Grand Teton NP	Nitrogen	0.066	0.002	0.039	0.000	0.020	0.026	0.038	0.035	1.5
	Sulfur	0.149	0.000	0.049	0.000	0.021	0.101	0.048	0.052	5.0
North Absaorka WA	Nitrogen	0.093	0.005	0.061	0.001	0.052	0.031	0.060	0.038	1.5
	Sulfur	0.133	0.001	0.070	0.000	0.063	0.063	0.070	0.048	5.0
North Cheyenne IR	Nitrogen	0.804	0.147	0.628	0.024	0.561	0.077	0.587	0.282	1.5
	Sulfur	0.954	0.028	0.796	0.004	0.727	0.145	0.790	0.197	5.0
Red Rock Lakes	Nitrogen	0.059	0.001	0.046	0.000	0.043	0.012	0.046	0.010	1.5
	Sulfur	0.072	0.000	0.044	0.000	0.038	0.028	0.044	0.015	5.0
Scapegoat WA	Nitrogen	0.023	0.001	0.016	0.000	0.019	0.006	0.016	0.003	1.5
	Sulfur	0.034	0.000	0.021	0.000	0.026	0.013	0.021	0.004	5.0
Teton WA	Nitrogen	0.069	0.003	0.041	0.000	0.023	0.026	0.040	0.035	1.5
	Sulfur	0.120	0.001	0.053	0.000	0.028	0.070	0.053	0.047	5.0
Theodore Roosevelt NP	Nitrogen	0.246	0.026	0.078	0.003	0.039	0.182	0.070	0.084	1.5
	Sulfur	0.313	0.005	0.089	0.000	0.046	0.225	0.088	0.072	5.0
U.L. Bend WA	Nitrogen	0.121	0.014	0.070	0.003	0.056	0.037	0.065	0.044	1.5
	Sulfur	0.152	0.003	0.083	0.001	0.075	0.066	0.082	0.039	5.0
Washakie WA	Nitrogen	0.097	0.006	0.055	0.001	0.038	0.036	0.054	0.057	1.5
	Sulfur	0.149	0.002	0.074	0.000	0.051	0.074	0.073	0.078	5.0
Wind Cave NP	Nitrogen	0.322	0.066	0.188	0.014	0.048	0.070	0.151	0.244	1.5
	Sulfur	0.437	0.015	0.298	0.001	0.063	0.124	0.293	0.331	5.0
Yellowstone NP	Nitrogen	0.090	0.004	0.060	0.001	0.052	0.026	0.059	0.032	1.5
	Sulfur	0.132	0.001	0.064	0.000	0.056	0.082	0.064	0.045	5.0
CLASS I / CLASS II SENSITIVE LAKES										
Black Joe Lake, Bridger WA	Nitrogen	0.114	0.007	0.057	0.000	0.012	0.050	0.056	0.096	1.5
	Sulfur	0.174	0.002	0.092	0.000	0.015	0.081	0.091	0.132	5.0
Deep Lake, Bridger WA	Nitrogen	0.119	0.007	0.059	0.000	0.012	0.054	0.058	0.102	1.5
	Sulfur	0.178	0.002	0.094	0.000	0.015	0.082	0.094	0.135	5.0
Emerald Lake, Cloud Peak WA	Nitrogen	0.165	0.031	0.090	0.004	0.047	0.044	0.080	0.109	1.5
	Sulfur	0.194	0.006	0.110	0.001	0.066	0.077	0.109	0.107	5.0
Florence, Cloud Peak WA	Nitrogen	0.174	0.037	0.093	0.004	0.046	0.043	0.083	0.120	1.5
	Sulfur	0.200	0.008	0.115	0.001	0.064	0.077	0.114	0.116	5.0
Hobbs Lake, Bridger WA	Nitrogen	0.084	0.003	0.043	0.000	0.008	0.037	0.043	0.070	1.5
	Sulfur	0.135	0.001	0.073	0.000	0.010	0.061	0.073	0.099	5.0
Lower Saddlebag, Popo Agie WA	Nitrogen	0.144	0.008	0.067	0.001	0.013	0.069	0.065	0.125	1.5
	Sulfur	0.217	0.002	0.108	0.000	0.016	0.107	0.108	0.171	5.0
Ross Lake, Cloud Peak WA	Nitrogen	0.068	0.003	0.036	0.000	0.010	0.030	0.035	0.053	1.5
	Sulfur	0.106	0.001	0.056	0.000	0.013	0.049	0.055	0.071	5.0
Upper Frozen Lake, Bridger WA	Nitrogen	0.129	0.007	0.062	0.000	0.011	0.060	0.061	0.112	1.5
	Sulfur	0.187	0.002	0.098	0.000	0.014	0.087	0.098	0.143	5.0

Table 3-7
Modeled Deposition of Nitrogen and Sulfur - 2020 Upper Production Scenario

Receptor Set	POLLUTANT	Maximum Deposition (kg/ha/yr)								Level of Concern (kg/ha/yr)
		ALL Sources	*CBNG*	*Coal-related Sources*	*Coal Mines*	*Montana Sources*	*Non-coal Sources*	*Power Plants*	*Wyoming Sources*	
CLASS I AREAS										
	Nitrogen	0.173	0.024	0.089	0.005	0.033	0.063	0.076	0.099	1.5
Badlands NP	Sulfur	0.231	0.006	0.128	0.001	0.044	0.100	0.126	0.121	5.0
	Nitrogen	0.007	0.000	0.004	0.000	0.004	0.002	0.004	0.002	1.5
Bob Marshall WA	Sulfur	0.010	0.000	0.005	0.000	0.006	0.005	0.005	0.002	5.0
	Nitrogen	0.165	0.007	0.069	0.001	0.012	0.090	0.067	0.148	1.5
Bridger WA	Sulfur	0.207	0.002	0.106	0.000	0.015	0.099	0.106	0.161	5.0
	Nitrogen	0.211	0.004	0.049	0.000	0.012	0.169	0.048	0.196	1.5
Fitzpatrick WA	Sulfur	0.142	0.001	0.078	0.000	0.016	0.081	0.078	0.108	5.0
	Nitrogen	0.090	0.009	0.036	0.002	0.029	0.046	0.032	0.029	1.5
Fort Peck IR	Sulfur	0.141	0.002	0.051	0.000	0.041	0.088	0.050	0.030	5.0
	Nitrogen	0.072	0.001	0.049	0.000	0.063	0.022	0.049	0.006	1.5
Gates of the Mountain WA	Sulfur	0.080	0.000	0.061	0.000	0.067	0.019	0.061	0.006	5.0
	Nitrogen	0.066	0.002	0.039	0.000	0.020	0.026	0.038	0.035	1.5
Grand Teton NP	Sulfur	0.149	0.000	0.049	0.000	0.021	0.101	0.049	0.052	5.0
	Nitrogen	0.094	0.005	0.062	0.001	0.053	0.031	0.060	0.038	1.5
North Absaorka WA	Sulfur	0.135	0.001	0.072	0.000	0.064	0.063	0.071	0.048	5.0
	Nitrogen	0.867	0.147	0.692	0.025	0.619	0.077	0.638	0.288	1.5
North Cheyenne IR	Sulfur	1.084	0.028	0.933	0.004	0.847	0.145	0.907	0.198	5.0
	Nitrogen	0.059	0.001	0.046	0.000	0.043	0.012	0.046	0.010	1.5
Red Rock Lakes	Sulfur	0.072	0.000	0.044	0.000	0.038	0.028	0.044	0.015	5.0
	Nitrogen	0.023	0.001	0.016	0.000	0.019	0.006	0.016	0.003	1.5
Scapegoat WA	Sulfur	0.034	0.000	0.021	0.000	0.026	0.013	0.021	0.004	5.0
	Nitrogen	0.070	0.003	0.041	0.000	0.023	0.026	0.040	0.035	1.5
Teton WA	Sulfur	0.120	0.001	0.053	0.000	0.028	0.070	0.053	0.047	5.0
	Nitrogen	0.247	0.026	0.080	0.003	0.040	0.182	0.071	0.085	1.5
Theodore Roosevelt NP	Sulfur	0.315	0.005	0.091	0.000	0.048	0.225	0.090	0.072	5.0
	Nitrogen	0.123	0.014	0.072	0.003	0.057	0.037	0.066	0.044	1.5
U.L. Bend WA	Sulfur	0.154	0.003	0.085	0.001	0.077	0.066	0.084	0.040	5.0
	Nitrogen	0.098	0.006	0.056	0.001	0.038	0.036	0.054	0.057	1.5
Washakie WA	Sulfur	0.150	0.002	0.074	0.000	0.052	0.074	0.074	0.078	5.0
	Nitrogen	0.330	0.066	0.196	0.016	0.050	0.070	0.153	0.250	1.5
Wind Cave NP	Sulfur	0.441	0.015	0.303	0.002	0.067	0.124	0.297	0.332	5.0
	Nitrogen	0.091	0.004	0.061	0.001	0.053	0.026	0.059	0.033	1.5
Yellowstone NP	Sulfur	0.132	0.001	0.065	0.000	0.057	0.082	0.065	0.045	5.0
CLASS I / CLASS II SENSITIVE LAKES										
	Nitrogen	0.114	0.007	0.057	0.000	0.012	0.050	0.056	0.096	1.5
Black Joe Lake, Bridger WA	Sulfur	0.174	0.002	0.092	0.000	0.016	0.081	0.092	0.132	5.0
	Nitrogen	0.120	0.007	0.059	0.000	0.012	0.054	0.058	0.102	1.5
Deep Lake, Bridger WA	Sulfur	0.178	0.002	0.094	0.000	0.015	0.082	0.094	0.135	5.0
	Nitrogen	0.168	0.031	0.093	0.004	0.049	0.044	0.081	0.111	1.5
Emerald Lake, Cloud Peak WA	Sulfur	0.197	0.006	0.113	0.001	0.069	0.077	0.111	0.107	5.0
	Nitrogen	0.177	0.037	0.097	0.004	0.047	0.043	0.084	0.122	1.5
Florence, Cloud Peak WA	Sulfur	0.203	0.008	0.119	0.001	0.067	0.077	0.117	0.116	5.0
	Nitrogen	0.084	0.003	0.044	0.000	0.008	0.037	0.043	0.070	1.5
Hobbs Lake, Bridger WA	Sulfur	0.135	0.001	0.073	0.000	0.011	0.061	0.073	0.099	5.0
	Nitrogen	0.144	0.008	0.067	0.001	0.013	0.069	0.066	0.125	1.5
Lower Saddlebag, Popo Agie WA	Sulfur	0.218	0.002	0.108	0.000	0.016	0.107	0.108	0.171	5.0
	Nitrogen	0.069	0.003	0.036	0.000	0.010	0.030	0.035	0.053	1.5
Ross Lake, Cloud Peak WA	Sulfur	0.106	0.001	0.056	0.000	0.014	0.049	0.056	0.071	5.0
	Nitrogen	0.129	0.007	0.062	0.000	0.012	0.060	0.061	0.112	1.5
Upper Frozen Lake, Bridger WA	Sulfur	0.187	0.002	0.098	0.000	0.015	0.087	0.098	0.143	5.0

Table 3-8
Change in Modeled Deposition of Nitrogen and Sulfur - 2020 Lower Production Scenario Minus Base Year (2004)

Receptor Set	POLLUTANT	Maximum Deposition (kg/ha/yr)								Level of Concern (kg/ha/yr)
		ALL Sources	*CBNG*	*Coal-related Sources*	*Coal Mines*	*Montana Sources*	*Non-coal Sources*	*Power Plants*	*Wyoming Sources*	
CLASS I AREAS										
Badlands NP	Nitrogen	0.045	0.011	0.033	0.001	0.021	0.001	0.025	0.025	1.5
	Sulfur	0.037	0.003	0.033	0.000	0.023	0.000	0.032	0.015	5.0
Bob Marshall WA	Nitrogen	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.000	1.5
	Sulfur	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.000	5.0
Bridger WA	Nitrogen	0.009	0.005	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.008	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0
Fitzpatrick WA	Nitrogen	0.006	0.003	0.004	0.000	0.003	0.000	0.004	0.004	1.5
	Sulfur	0.005	0.001	0.005	0.000	0.003	0.000	0.005	0.002	5.0
Fort Peck IR	Nitrogen	0.018	0.004	0.013	0.000	0.008	0.000	0.011	0.009	1.5
	Sulfur	0.016	0.001	0.015	0.000	0.012	0.000	0.015	0.005	5.0
Gates of the Mountain WA	Nitrogen	0.006	0.000	0.005	0.000	0.005	0.000	0.005	0.001	1.5
	Sulfur	0.005	0.000	0.005	0.000	0.005	0.000	0.005	0.001	5.0
Grand Teton NP	Nitrogen	0.003	0.001	0.002	0.000	0.001	0.000	0.002	0.002	1.5
	Sulfur	0.003	0.000	0.003	0.000	0.002	0.000	0.003	0.002	5.0
North Absaorka WA	Nitrogen	0.018	0.003	0.016	0.000	0.014	0.000	0.015	0.004	1.5
	Sulfur	0.017	0.001	0.016	0.000	0.014	0.000	0.016	0.002	5.0
North Cheyenne IR	Nitrogen	0.489	0.008	0.497	0.001	0.464	0.011	0.473	0.055	1.5
	Sulfur	0.569	0.003	0.567	0.000	0.534	0.001	0.563	0.031	5.0
Red Rock Lakes	Nitrogen	0.003	0.001	0.003	0.000	0.002	0.000	0.003	0.001	1.5
	Sulfur	0.003	0.000	0.003	0.000	0.002	0.000	0.003	0.001	5.0
Scapegoat WA	Nitrogen	0.003	0.000	0.002	0.000	0.002	0.000	0.002	0.001	1.5
	Sulfur	0.003	0.000	0.003	0.000	0.002	0.000	0.003	0.000	5.0
Teton WA	Nitrogen	0.009	0.002	0.006	0.000	0.006	0.000	0.006	0.003	1.5
	Sulfur	0.004	0.000	0.007	0.000	0.006	0.000	0.007	0.002	5.0
Theodore Roosevelt NP	Nitrogen	0.024	0.012	0.028	0.001	0.018	0.000	0.023	0.023	1.5
	Sulfur	0.027	0.002	0.026	0.000	0.018	0.000	0.025	0.011	5.0
U.L. Bend WA	Nitrogen	0.036	0.006	0.030	0.000	0.024	0.001	0.027	0.012	1.5
	Sulfur	0.034	0.001	0.032	0.000	0.027	0.000	0.032	0.007	5.0
Washakie WA	Nitrogen	0.017	0.004	0.012	0.000	0.012	0.000	0.012	0.006	1.5
	Sulfur	0.013	0.001	0.012	0.000	0.013	0.000	0.011	0.003	5.0
Wind Cave NP	Nitrogen	0.104	0.030	0.072	0.003	0.033	0.002	0.045	0.071	1.5
	Sulfur	0.076	0.007	0.069	0.000	0.036	0.001	0.065	0.042	5.0
Yellowstone NP	Nitrogen	0.017	0.002	0.008	0.000	0.010	0.000	0.007	0.003	1.5
	Sulfur	0.003	0.000	0.012	0.000	0.012	0.000	0.012	0.002	5.0
CLASS I / CLASS II SENSITIVE LAKES										
Black Joe Lake, Bridger WA	Nitrogen	0.010	0.005	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.007	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0
Deep Lake, Bridger WA	Nitrogen	0.009	0.004	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.007	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0
Emerald Lake, Cloud Peak WA	Nitrogen	0.045	0.013	0.030	0.000	0.020	0.003	0.023	0.025	1.5
	Sulfur	0.031	0.002	0.028	0.000	0.021	0.001	0.027	0.010	5.0
Florence, Cloud Peak WA	Nitrogen	0.051	0.018	0.031	0.001	0.020	0.003	0.024	0.031	1.5
	Sulfur	0.033	0.003	0.029	0.000	0.022	0.001	0.028	0.011	5.0
Hobbs Lake, Bridger WA	Nitrogen	0.005	0.002	0.003	0.000	0.002	0.000	0.003	0.004	1.5
	Sulfur	0.005	0.001	0.004	0.000	0.002	0.000	0.004	0.003	5.0
Lower Saddlebag, Popo Agie WA	Nitrogen	0.012	0.006	0.006	0.000	0.003	0.000	0.005	0.008	1.5
	Sulfur	0.008	0.001	0.007	0.000	0.003	0.000	0.007	0.005	5.0
Ross Lake, Cloud Peak WA	Nitrogen	0.006	0.002	0.004	0.000	0.002	0.000	0.003	0.003	1.5
	Sulfur	0.005	0.001	0.004	0.000	0.002	0.000	0.004	0.002	5.0
Upper Frozen Lake, Bridger WA	Nitrogen	0.009	0.004	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.007	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0

Table 3-9
Change in Modeled Deposition of Nitrogen and Sulfur - 2020 Upper Production Scenario Minus Base Year (2004)

Receptor Set	POLLUTANT	Maximum Deposition (kg/ha/yr)								Level of Concern (kg/ha/yr)
		ALL Sources	*CBNG*	*Coal-related Sources*	*Coal Mines*	*Montana Sources*	*Non-coal Sources*	*Power Plants*	*Wyoming Sources*	
CLASS I AREAS										
Badlands NP	Nitrogen	0.048	0.011	0.036	0.001	0.022	0.001	0.026	0.027	1.5
	Sulfur	0.039	0.003	0.036	0.000	0.025	0.000	0.034	0.015	5.0
Bob Marshall WA	Nitrogen	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.000	1.5
	Sulfur	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.000	5.0
Bridger WA	Nitrogen	0.010	0.005	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.008	0.001	0.006	0.000	0.003	0.000	0.006	0.005	5.0
Fitzpatrick WA	Nitrogen	0.006	0.003	0.004	0.000	0.003	0.000	0.004	0.004	1.5
	Sulfur	0.005	0.001	0.005	0.000	0.003	0.000	0.005	0.002	5.0
Fort Peck IR	Nitrogen	0.019	0.004	0.015	0.000	0.009	0.000	0.012	0.009	1.5
	Sulfur	0.017	0.001	0.017	0.000	0.013	0.000	0.016	0.005	5.0
Gates of the Mountain WA	Nitrogen	0.006	0.000	0.006	0.000	0.005	0.000	0.005	0.001	1.5
	Sulfur	0.005	0.000	0.005	0.000	0.005	0.000	0.005	0.001	5.0
Grand Teton NP	Nitrogen	0.003	0.001	0.002	0.000	0.001	0.000	0.002	0.002	1.5
	Sulfur	0.003	0.000	0.003	0.000	0.002	0.000	0.003	0.002	5.0
North Absaorka WA	Nitrogen	0.020	0.003	0.016	0.000	0.015	0.000	0.015	0.004	1.5
	Sulfur	0.018	0.001	0.018	0.000	0.016	0.000	0.017	0.002	5.0
North Cheyenne IR	Nitrogen	0.553	0.008	0.561	0.002	0.523	0.011	0.524	0.062	1.5
	Sulfur	0.699	0.003	0.704	0.000	0.655	0.001	0.680	0.032	5.0
Red Rock Lakes	Nitrogen	0.004	0.001	0.003	0.000	0.002	0.000	0.003	0.001	1.5
	Sulfur	0.003	0.000	0.003	0.000	0.002	0.000	0.003	0.001	5.0
Scapegoat WA	Nitrogen	0.003	0.000	0.002	0.000	0.002	0.000	0.002	0.001	1.5
	Sulfur	0.003	0.000	0.003	0.000	0.003	0.000	0.003	0.000	5.0
Teton WA	Nitrogen	0.010	0.002	0.007	0.000	0.006	0.000	0.006	0.003	1.5
	Sulfur	0.004	0.000	0.007	0.000	0.007	0.000	0.007	0.002	5.0
Theodore Roosevelt NP	Nitrogen	0.026	0.012	0.031	0.001	0.019	0.000	0.024	0.024	1.5
	Sulfur	0.029	0.002	0.029	0.000	0.020	0.000	0.028	0.011	5.0
U.L. Bend WA	Nitrogen	0.038	0.006	0.032	0.000	0.025	0.001	0.028	0.013	1.5
	Sulfur	0.036	0.001	0.035	0.000	0.029	0.000	0.034	0.007	5.0
Washakie WA	Nitrogen	0.017	0.004	0.013	0.000	0.013	0.000	0.012	0.006	1.5
	Sulfur	0.014	0.001	0.013	0.000	0.014	0.000	0.012	0.003	5.0
Wind Cave NP	Nitrogen	0.112	0.030	0.080	0.005	0.035	0.002	0.047	0.077	1.5
	Sulfur	0.081	0.007	0.074	0.000	0.040	0.001	0.069	0.043	5.0
Yellowstone NP	Nitrogen	0.017	0.002	0.009	0.000	0.010	0.000	0.008	0.003	1.5
	Sulfur	0.003	0.000	0.013	0.000	0.013	0.000	0.012	0.002	5.0
CLASS I / CLASS II SENSITIVE LAKES										
Black Joe Lake, Bridger WA	Nitrogen	0.010	0.005	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.007	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0
Deep Lake, Bridger WA	Nitrogen	0.010	0.004	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.007	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0
Emerald Lake, Cloud Peak WA	Nitrogen	0.048	0.013	0.033	0.001	0.022	0.003	0.025	0.026	1.5
	Sulfur	0.034	0.002	0.031	0.000	0.024	0.001	0.030	0.010	5.0
Florence, Cloud Peak WA	Nitrogen	0.054	0.018	0.034	0.001	0.022	0.003	0.025	0.032	1.5
	Sulfur	0.036	0.003	0.032	0.000	0.025	0.001	0.031	0.011	5.0
Hobbs Lake, Bridger WA	Nitrogen	0.006	0.002	0.004	0.000	0.002	0.000	0.003	0.004	1.5
	Sulfur	0.005	0.001	0.004	0.000	0.002	0.000	0.004	0.003	5.0
Lower Saddlebag, Popo Agie WA	Nitrogen	0.012	0.006	0.006	0.000	0.004	0.000	0.005	0.008	1.5
	Sulfur	0.009	0.001	0.007	0.000	0.004	0.000	0.007	0.005	5.0
Ross Lake, Cloud Peak WA	Nitrogen	0.006	0.002	0.004	0.000	0.002	0.000	0.003	0.004	1.5
	Sulfur	0.005	0.001	0.005	0.000	0.003	0.000	0.004	0.002	5.0
Upper Frozen Lake, Bridger WA	Nitrogen	0.010	0.004	0.005	0.000	0.003	0.000	0.004	0.007	1.5
	Sulfur	0.007	0.001	0.006	0.000	0.003	0.000	0.006	0.004	5.0

The projected changes in ANC are provided in **Table 3-10** for the analyzed lakes. Modeling results are provided for the base year (2004) analysis as well as the lower and upper production scenarios for 2020. The level of acceptable change was based on a 10 percent change in ANC for lakes with an ANC of 25 µeq/L or greater and a 1 µeq/L threshold change for lakes with an ANC value of less than 25 µeq/L.

Table 3-10
Modeled Impacts on Acid Neutralizing Capacity of Sensitive Lakes – 2020 Production Scenarios

Location	Lake	Background ANC (µeq/L)	Area (hectares)	Base Year (2004) Change (percent)	2020 Lower Development Scenario Change (percent)	2020 Upper Development Scenario Change (percent)	Thresholds (percent)
Bridger WA	Black Joe	67	890	4.00	4.26	4.27	10
	Deep	60	205	4.70	4.98	4.99	10
	Hobbs	70	293	3.95	4.14	4.15	10
	Upper Frozen	5	64.8	2.42	2.55	2.56	1[1]
Cloud Peak WA	Emerald	55.3	293	5.24	6.69	6.80	10
	Florence	32.7	417	9.09	11.79	11.99	10
Fitzpatrick WA	Ross	53.5	4,455	2.72	2.89	2.90	10
Popo Agie WA	Lower Saddlebag	55.5	155	6.28	6.65	6.67	10

[1] Threshold value for Upper Frozen Lake is reported as the ANC in µeq/L, which is the standard for lakes with less than 25 µeq/L ANC (USFS 2000).

At Upper Frozen Lake, the base year (2004) impact was 2.4 µeq/L, which is significantly above the threshold value of 1 µeq/L for these lakes. The modeled results for both 2020 production scenarios show minor reductions to the ANC level at Upper Frozen Lake with a total ANC of 2.6 µeq/L.

For Florence Lake, the modeled base year impacts are 90 percent of the ANC threshold, and projected 2020 development levels contribute to impacts that cause an exceedance of the threshold.

The modeling results indicate that the proposed development scenarios may lead to impacts above the ANC threshold for two lakes in the region, although the percent change in predicted 2020 upper development scenario ANC values relative to the base year are 6 and 30 percent for Upper Frozen Lake and Florence Lake, respectively.

3.1.7 Analysis of Hazardous Air Pollutant Impacts

The study also modeled hazardous air pollutant (HAP) impacts from sources in the PRB study area. Only those areas with the greatest ambient air quality impacts were analyzed for HAP impacts. The greatest ambient air impacts are anticipated to occur only in the near-field. These areas included Wyoming and Montana near-field receptors for annual (chronic) and 1-hour (acute) impacts. Results of the 1-hour modeled impacts were compared to the reference exposure levels (RELs) (USEPA 2007). **Table 3-11** provides an analysis of the short-term impacts for the six analyzed compounds (benzene, ethyl benzene, formaldehyde, n-hexane, toluene, and xylene) compared to the RELs. Results show that potential impacts from these compounds would be well below the RELs at all locations.

Table 3-11
Modeled Maximum Acute Concentrations of Hazardous Air Pollutants at Near-field Receptors from All Sources

Receptor Set	Pollutant	Averaging Period[1]	Base Year (2004)	2020 Lower Development Scenario	2020 Upper Development Scenario	REL
Near-field Receptors			**All Data in μg/m³**			
Montana Near-field Receptors	Benzene	1-hour	4.9E-02	6.4E-02	9.9E-02	1,300
	Ethyl Benzene	1-hour	3.5E-03	4.7E-03	7.2E-03	35,000
	Formaldehyde	1-hour	1.2E-01	1.2E-01	1.2E-01	94
	n-Hexane	1-hour	4.0E+00	4.0E+00	4.0E+00	39,000
	Toluene	1-hour	9.0E-03	1.2E-02	1.8E-02	37,000
	Xylene	1-hour	1.1E-03	1.4E-03	2.2E-03	22,000
Wyoming Near-field Receptors	Benzene	1-hour	9.4E-02	1.2E-01	1.4E-01	1,300
	Ethyl Benzene	1-hour	6.8E-03	8.8E-03	1.0E-02	35,000
	Formaldehyde	1-hour	1.4E-01	1.4E-01	1.4E-01	94
	n-Hexane	1-hour	4.8E+00	4.8E+00	4.8E+00	39,000
	Toluene	1-hour	1.7E-02	2.2E-02	2.6E-02	37,000
	Xylene	1-hour	2.1E-03	2.6E-03	3.1E-03	22,000

[1] Data for ethyl benzene and n-hexane are based on Immediately Dangerous to Life or Health (IDLH)/100 values.

The impacts for chronic and carcinogenic risks are provided in **Table 3-12** for the Montana and Wyoming near-field receptor grids. Based on the modeling results, potential impacts from these compounds would be well below the non-carcinogenic reference concentrations for chronic inhalation (RfCs). The impacts for carcinogenic risk also are provided in **Table 3-12**. Potential impacts from these compounds would be well below the 1 x 10^{-6} risk. The greatest increase in the carcinogenic risk is for the Wyoming near-field where the carcinogenic risk due to benzene increases 52 percent under the 2020 upper production scenario relative to the base year risk. Despite the increases, these impacts remain 3 percent or less of the threshold of acceptable risk range of 1 x 10^{-4} to 1 x 10^{-6}, as provided by the USEPA (2007).

3.2 Comparison to Original Study

With a few notable exceptions, the original Task 3A qualitative projections for 2020 are consistent with the findings of the current update. One important difference between the updated Task 3A studies (for both 2015 and 2020) and the original Task 3A study is the large increase in projected 2015 and 2020 impacts due to CBNG development. While the original Task 3A study was based on preliminary Task 2 CBNG development production, this updated study used the final Task 2 (October 2005) development projections for CBNG, which were 15 to 30 percent greater than the projections used in the original Task 3A Report. This increase suggests that while previously coal development was the most substantial contributor to projected future year increases, based on the final Task 2 projections, CBNG development may have a secondary, or even primary, contribution to air quality impacts. Additionally, revisions of the base year emissions inventory might be substantial when comparing base year modeled impacts; however, it is difficult to determine if this is in fact the case because the model version and base year meteorology were not the same. Despite revisions to many of the tools used to analyze cumulative air quality impacts, the overall results and projected changes of this updated study generally are consistent with the original Task 1A and 3A results.

Table 3-12
Modeled Maximum Annual Concentrations of Hazardous Air Pollutants at Near-field Receptors from All Sources

Receptor Set	Pollutant	Averaging Period[1]	Base Year (2004)	2020 Lower Development Scenario	2020 Upper Development Scenario	Non-carcinogenic RfCs
Near-field Receptors – Non-carcinogenic Impacts			**All Data in μg/m³**			
Montana Near-field Receptors	Benzene	Annual	1.37E-04	1.80E-04	2.67E-04	30
	Ethyl Benzene	Annual	9.14E-06	1.22E-05	1.85E-05	1,000
	Formaldehyde	Annual	3.38E-03	3.38E-03	3.38E-03	9.8
	n-Hexane	Annual	1.12E-01	1.12E-01	1.12E-01	700
	Toluene	Annual	1.80E-04	1.81E-04	1.81E-04	5,000
	Xylene	Annual	2.87E-06	3.80E-06	5.70E-06	100
Wyoming Near-field Receptors	Benzene	Annual	3.82E-03	4.91E-03	5.71E-03	30
	Ethyl Benzene	Annual	2.76E-04	3.55E-04	4.12E-04	1,000
	Formaldehyde	Annual	2.13E-03	2.14E-03	2.14E-03	9.8
	n-Hexane	Annual	7.02E-02	7.02E-02	7.02E-02	700
	Toluene	Annual	7.21E-04	9.22E-04	1.07E-03	5,000
	Xylene	Annual	8.33E-05	1.07E-04	1.24E-04	100
Near-field Receptors – Carcinogenic Risk Evaluation[1]			**Risk Evaluation X 10^{-6}**			
Montana	Benzene	Annual	0.001	0.001	0.001	--
	Formaldehyde	Annual	0.031	0.031	0.031	--
Wyoming	Benzene	Annual	0.021	0.027	0.032	--
	Formaldehyde	Annual	0.020	0.020	0.020	--

[1] Benzene concentrations multiplied by risk factor: 7.8 X 10^{-6} X 0.71. Formaldehyde Concentrations multiplied by risk factor: 1.3 X 10^{-5} X 0.71.

Generally, the method used for projecting future year emissions was consistent between the original Task 3A report and this updated analysis; however, updated information was used in this analysis where available. Several coal-fired power plants have revised their generating capacity, as discussed in Section 2.4 Emissions Input Data. This information was used to project the 2020 upper and lower development scenarios accordingly. Additionally, the projected CBNG development activity had changed between the completion of the original Task 3A modeling analysis and the finalization of the Task 2 Report (ENSR 2005b, 2006). The finalized CBNG production levels from the Task 2 Report were used for this updated analysis. Importantly, new CBNG well locations were modeled for this updated analysis to depict the spatial shifting of well locations. **Table 3-13** provides estimated production levels, by source groups, for the original Task 3A report compared to values used for this updated analysis.

The comparison between this updated analysis and the earlier qualitative projections for 2020 in the original Task 3A report is affected to some extent by these updated production levels and their associated emissions. Overall, coal-fired power plants had limited effect on base year air quality; however, the incorporation of RFD power plants in Montana did affect areas in close proximity to the PRB, such as the Northern Cheyenne IR. Additionally, changes to CBNG production had a noticeable effect on the comparison of qualitative projections for 2020 and the modeled findings from this updated analysis. While previously coal development was the most significant contributor to projected future year increases, now CBNG development may have a secondary, or even primary, contribution to air quality impacts at some location.

Table 3-13
Comparison of Projected Development Levels by Source Group

Group	Base Year (2004)	Development Units	Scenario	Projected Development Levels – Original Task 3A 2010	2015	2020	Projected Development Levels – Updated Analysis[1] 2010	2015	2020
Conventional Oil and Gas Sources	39.9	BCF	Same for both scenarios	42.7	39.0	35.1	42.7	39.0	35.1
CBNG Sources	338	BCF	Same for both scenarios	554	530	521	640	694	631
Coal Production, Wyoming	363	mmtpy	Lower	411	467	495	411	467	495
			Upper	479	543	576	479	543	576
Coal Production, Montana	36.1	mmtpy	Lower	41	48	56	41	48	56
			Upper	51	74	83	51	74	83
Power Plants, Wyoming	512	MW Generating Capacity	Lower	1,262	1,262	1,262	1,262	2,002	2,002
			Upper	1,512	1,512	1,962	1,512	2,002	2,702
Power Plants, Montana	2,576	MW Generating Capacity	Lower	2,689	3,439	3,439	2,689	2,802	3,552
			Upper	2,689	3,439	4,189	2,689	2,802	4,302

[1] Projected development for 2010 and 2020 did not change from the Task 2 Report (ENSR 2005b), with the exception of RFD scenarios for power plants that were revised specifically for 2015 and 2020 based on updated information. For this reason, the projected power plant development levels have changed for 2015 and 2020.

3.2.1 Impacts on Ambient Air Quality

3.2.1.1 Wyoming Near-field Impacts

The original Task 3A qualitative analysis for 2015 and 2020 suggested that "coal production is anticipated to contribute substantially to impacts on the near-field receptor grid in Wyoming, particularly PM_{10} impacts … and the projected increase in coal production likely would continue to affect the PM_{10} air quality levels." This statement is supported by the findings in this updated study. Additionally, this updated study suggests that PM_{10} impacts are indicative of $PM_{2.5}$ impacts. While, similar to previous findings, 24-hour and annual exceedances of these pollutants are projected to occur in 2020, this updated study suggests that these trends primarily are due to projected CBNG development rather than solely due to coal development. Nonetheless, as shown in **Figures 3-2, 3-3,** and **3-4**, exceedances still would be limited to small individual receptor areas in the near-field.

Power plant emissions are still projected to be the major contributors to increased annual impacts of SO_2 in the near-field receptor grid for the 2020 modeled impacts; however, under shorter averaging periods (24-hour and 3-hour) SO_2 impacts predicted for 2020 are dominated by CBNG development. Regardless of the source contribution to SO_2 impacts, the predicted impacts would continue to be well below ambient standards despite substantial increases in projected development.

The NO_2 impacts are the result of emissions from all source groups with base year impacts dominated by coal production and future year impacts predicted to result from CBNG development. At the time of the original study, it was unclear if the NO_2 standard would be exceeded in 2015 or

2020 as a result of projected development in the PRB study area, but results from this updated study do not show any exceedances.

3.2.1.2 Montana Near-field Impacts

In general the original predicted Montana near-field impacts for 2015 and 2020 are substantially different for this updated study. The base year impacts are substantially different between the original study and the updated studies (both 2015 and 2020 updates), and it is believed that this is a result of the revised emission inventory. The differences of SO_2 impacts are relatively minor, while predicted NO_2 and PM impacts are notably lower than original predictions. In addition to changes in the base year inventory, it is predicted that the CBNG shifting of well locations will reduce Montana near-field impacts relative to 2015 projections. Despite these substantial differences, the modeled impacts on the Montana near-field receptors were well below the ambient standards for all pollutants, and continue to remain below the ambient standards into the future.

In the original study, coal production contributed substantially to impacts on the near-field receptor grid in Montana, while in this updated study, the source contribution to maximum impacts includes both CBNG, power plants, and coal sources, depending on the air pollutant.

3.2.2 Impacts at Class I Area Receptors

As noted in Section 3.1.2, the projected impacts in Class I areas in 2020 would be below the ambient standards. The PM_{10} and $PM_{2.5}$ impacts at the Northern Cheyenne IR and Wind Cave NP were greater than any other Class I area, and those impacts tended to result from sources in Wyoming with no single source type clearly dominating impacts. The 24-hour PM_{10} impact at both of these Class I areas is higher than the comparative PSD increment. These results are consistent with the original study's projections.

3.2.3 Impacts at Sensitive Class II Areas

From the 2010 modeling results, the Crow IR and Cloud Peak WA showed the highest air quality impacts for the identified sensitive Class II areas. Current modeling results are consistent with the qualitative impacts from the original study, with 2020 impacts in the Crow IR predicted to be the highest of the Class II areas evaluated, and impacts at all areas remaining below ambient standards.

3.2.4 Impacts on Visibility

Model results of visibility impacts at Class I areas and identified Class II areas (Section 3.1.4) showed that a large number of days had modeled impacts for 2010 above 10 percent (1 dv) reduction in visibility at all identified areas. The base year visibility impacts for Class I areas exhibited a small decrease in this updated study relative to the original Task 3A study; however, base year impacts at Class II areas showed a marked increase, with two Class II area predicted to have more than 300 days per year with more than a 10 percent change in visibility due to regional sources. The substantial differences in base year impacts did not appreciably alter the original projected impacts for 2020 projected in the Task 3A Report. While it was predicted that in 2010 Class I areas would have an increase of up to 20 more days per year that experience greater than

10 percent change in visibility, it is predicted that in 2020, the number of days with a 10 percent change would increase to more than 60 for the Northern Cheyenne IR.

3.2.5 Impacts on Acid Deposition and Sensitive Lake Acid Neutralizing Capacity

Results of the change in ANC for the identified lakes for both 2010 and 2020 showed that deposition at two separate lakes would result in reductions in ANC greater than the established thresholds. Those lakes (Upper Frozen Lake and Florence Lake) would continue to be impacted by the increased development in the PRB study area. However, impacts to the other lakes were well below the thresholds, and expected increases in development likely would not lead to impacts at the other sensitive lakes.

Modeled impacts on acid deposition in Class I areas for 2010 and 2020 also were well below the established sensitive thresholds. Increased development would not likely lead to exceedances of those thresholds for any identified sensitive areas.

3.2.6 Analysis of Hazardous Air Pollutant Emissions

The original base year (2002) study and the analysis of development for 2010 showed that the modeled formaldehyde levels were above the 1-hour REL at the near-field receptor grid in Wyoming. For this updated study the predicted impacts for HAPs were well below all established thresholds, and increased development in 2020 would not likely lead to any exceedances.

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Appendix A

National and State Ambient Air Quality Standards for the PRB Coal Review

Table A-1
National and State Ambient Air Quality Standards
For the PRB Coal Review

Pollutant	Averaging Period	National	Wyoming	Montana
PM_{10}	Annual	50 µg/m^3 arithmetic average	Same as NAAQS	50 µg/m^3, state and federal violation when more than one expected exceedance per calendar year, averaged over 3 years.
	24-hour	The 150 µg/m^3 standard has been revoked at the date of this report.	150 µg/m^3, maximum average concentration, no more than one exceedance per year.	150 µg/m^3, state and federal violation when the 3-year average of the arithmetic means over a calendar year exceeds the standard.
$PM_{2.5}$	Annual	15 µg/m^3, 3-year average of annual arithmetic mean.	15 µg/m^3, annual arithmetic mean	Same as NAAQS.
	24-Hour	35 µg/m^3, 98th percentile of the 24-hour values determined for each year. 3-year average of the 98th percentile values.	35 µg/m^3, 98th percentile 24-hour average	Same as NAAQS.
SO_2	Annual	0.03 ppm (80 µg/m^3), annual arithmetic mean not to be exceeded in any calendar year.	60 µg/m^3, arithmetic mean	0.02 ppm, state violation when the arithmetic average over any four consecutive quarters exceeds the standard.
	24-hour	0.14 ppm (365 µg/m^3), not to be exceeded more than once in any calendar year	260 µg/m^3, maximum concentration not to be eceeded more than once per year	10 ppm, rolling average, not to be exceeded more than once every 12 consecutive months.
	3-hour	0.50 ppm (1,300 µg/m^3), not to be exceeded more than once in any calendar year (secondary standard)	1,300 µg/m^3 (0.50 ppm), maximum concentration not to be exceeded more than once per year.	Same as NAAQS.
	1-hour	No standard	--	0.5 ppm, not to be exceeded more than 18 times in any 12 consecutive months.
CO	8-hour	10 mg/m^3 (9 ppm), maximum concentration not to be exceeded more than once per year	Same as NAAQS	9 ppm, not to be exceeded more than once over any 12 consecutive months.
	1-hour	35 ppm (40 mg/m^3), maximum concentration not to be exceeded more than once per year.	Same as NAAQS	23 ppm, not to be exceeded more than once over any 12 consecutive months.
NO_2	Annual	0.053 ppm (100 µg/m^3) Annual arithmetic mean	Same as NAAQS	0.05 ppm, not to be exceeded more than once over any 12 consecutive months.
	1-hour	--	--	0.30 ppm, not to be exceeded more than once over any 12 consecutive months.

[1]Hydrogen sulfide, ozone, and lead are not being modeled for this study; hence, they are not included in this table.

Exhibit 14

U.S. EPA, Clean Air Markets Data for 13 Coal-fired Power Plants (Aug. 27, 2011)

Facility Level Emissions Quick Report
August 27, 2011

Your query will return data for 13 facilities and 39 units.

You specified: **Year(s):** 2010 **Program:** ARP **Facility:** Sooner, Nebraska City Station, Martin Drake, North Omaha Station, Northeastern, Laramie River, Ray D Nixon, Muskogee, Gerald Gentleman Station, Riverton, Holcomb, La Cygne, Springerville Generating Station

State	Facility Name	Facility ID (ORISPL)	Year	Program(s)	# of Months Reported	SO_2 Tons	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
AZ	Springerville Generating Station	8223	2010	ARP	12	6,738.5	6,535.0	11,213,477.8	106,976,587
CO	Martin Drake	492	2010	ARP	12	6,033.7	3,415.3	1,966,854.6	19,004,948
CO	Ray D Nixon	8219	2010	ARP	12	4,077.6	1,999.1	1,897,648.7	18,110,846
KS	Holcomb	108	2010	ARP	12	1,710.8	4,234.5	2,909,436.8	27,740,634
KS	La Cygne	1241	2010	ARP	12	20,500.3	9,587.5	10,001,421.9	95,360,619
KS	Riverton	1239	2010	ARP	12	4,204.6	1,145.7	757,928.9	8,143,451
NE	Gerald Gentleman Station	6077	2010	ARP	12	29,741.1	13,164.5	10,298,558.6	98,193,661
NE	Nebraska City Station	6096	2010	ARP	12	14,295.6	8,830.3	8,506,116.5	81,103,348
NE	North Omaha Station	2291	2010	ARP	12	10,515.2	6,765.2	4,065,276.3	38,820,664
OK	Muskogee	2952	2010	ARP	12	24,208.9	15,058.5	9,013,266.1	86,026,756
OK	Northeastern	2963	2010	ARP	12	18,562.2	14,896.2	8,420,861.5	94,905,821
OK	Sooner	6095	2010	ARP	12	16,925.2	9,632.2	6,417,241.9	61,207,307
WY	Laramie River	6204	2010	ARP	12	9,378.1	16,507.7	14,724,743.5	140,396,130
Total						**166,891.6**	**111,771.7**	**90,192,833.1**	**875,990,772**

Exhibit 15

U.S. EPA, Toxic Release Inventory Data for Martin Drake Coal-fired Power Plant (2011)

http://oaspub.epa.gov/enviro/tris_control.tris_print?tris_id=80903MRTND700SC
Last updated on 08/27/2011

Toxics Release Inventory (TRI)

You are here: EPA Home Envirofacts TRI Envirofacts Report

Envirofacts Report

Report an Error

Query executed on AUG-27-2011
Results are based on data extracted on

Click on "View Facility Information" to view EPA Facility information for the facility.

Facility Name:	COLORADO SPRINGS UTILITIES MARTIN DRAKE POWER PLANT	Mailing Name:	COLORADO SPRINGS UTILITIES MARTIN DRAKE POWER PLANT		
Address:	700 S CONEJOS ST COLORADO SPRINGS CO 80903	Mailing Address:	PO BOX 1103 MAIL CODE 0940121 S TEJON STREET, 4TH FLOOR COLORADO SPRINGS CO 80947		
County:	EL PASO	Region:	8		
Facility Information:	View Facility Information	TRI ID:	80903MRTND700SC	DUNS Number:	122464803
		FRS ID	110009559637		
TRI Preferred Latitude:		TRI Preferred Longitude:			
Public Contact:	MARK MURPHY	Phone:	7196683831		
Parent Company:	COLORADO SPRINGS UTILITIES	Parent DUNS:	127711760		

Starting with Reporting Year 2006, TRI Facilities began reporting NAICS codes, instead of SIC codes, to identify their Primary Business Activities.

NAICS Codes for 2010

NAICS CODE	PRIMARY	NAICS DESCRIPTION
221112	YES	Fossil Fuel Electric Power Generation

The above information comes from 2010, which was the last year NAICS code data was reported for this facility. The earliest NAICS code data on file for this facility was reported in 1998.

Map this facility

Map this facility using one of Envirofact's mapping utilities.

Besides TRI, this facility also does the following:

- has reported air releases under the Clean Air Act
- has permits to discharge to water

More information about these additional regulatory aspects of this facility can be found by pressing the other regulatory data button below.

Other Regulatory Data

Total Aggregate Releases of TRI Chemicals to the Environment:

For all releases estimated as a range, the mid-point of the range was used in these calculations. This table summarizes the releases reported by the facility. ***NR*** *- signifies nothing reported by this facility for the corresponding medium.*

Total Aggregate Releases of TRI Chemicals excluding Dioxin and Dioxin-like Compounds (Measured in Pounds)

Media	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	199
Air Emissions	92138.22	151465.98	129179.85	90428.4	101321.501	124494.1	66175.9	115402.5	121807.1	130558.8	103528	89515	845
Surface Water Discharges	0	.1	0	0	0	0	0	.1	0	0	0	NR	
Releases to Land	.1	0	.08	.13	.11	.09	.24	0	0	0	.2	NR	
Underground Injection	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	
Total On-Site Releases	92138.32	151466.08	129179.93	90428.53	101321.611	124494.19	66176.14	115402.6	121807.1	130558.8	103528.2	89515	845
Transfer Off-Site to Disposal	398755.6	503305.89	595962	594232.8	600131	709612.7	544635.3	575578.5	561216.9	468752.5	474648.1	322000	3192
Total Releases	490893.92	654771.97	725141.93	684661.33	701452.611	834106.89	610811.44	690981.1	683024	599311.3	578176.3	411515	4037

Graphic Summary of this Table

Total Aggregate Releases of Dioxin and Dioxin-like Compounds (Measured in Grams)

Media	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Air Emissions	1.38	1.499	1.47	.79	.7	.8	.7	.79	.71	.75	.71	NR	NR
Surface Water Discharges	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Releases to Land	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Underground Injection	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Total On-Site Releases	1.38	1.499	1.47	.79	.7	.8	.7	.79	.71	.75	.71	NR	NR
Transfer Off-Site to Disposal	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Total Releases	1.38	1.499	1.47	.79	.7	.8	.7	.79	.71	.75	.71	NR	NR

Graphic Summary of this Table

TRI Chemicals Reported on Form A:

The facility has certified that for each chemical listed below, the annual release did not exceed 500 pounds for the reporting year listed and the listed chemical was not manufactured, processed, or otherwise used in an amount exceeding 1 million pounds in the reporting year. Form A can not be filed for PBT chemicals (except certain instances of reporting lead in stainless steel, brass, or bronze alloys).

Chemical Name	TRI Chemical ID	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
COPPER	007440508	Not Reported	Not Reported	Reported	Reported	Reported	Reported	Reported	Not Reported	Reported	Reported	Reported	Reported	Not Reported

NOTE:
All chemicals reported below have release or transfer amounts greater than zero. To see a list of all chemicals reported by this facility click here.

Names and Amounts of Chemicals Released to the Environment by Year.

For all releases estimated as a range, the mid-point of the range was used in these calculations. ***NR*** *- signifies nothing reported for this facility by the corresponding medium. Rows with all "0" or "NR" values were not listed.*

Chemical Name	Media	Unit Of Measure	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
BARIUM COMPOUNDS (TRI Chemical ID:	AIR FUG	Pounds	15	15	13	12	13	15	12	12	250	5	250	5	5

N040)															
BARIUM COMPOUNDS (TRI Chemical ID: N040)	AIR STACK	Pounds	351	360	319	298	308	355	303	302	250	250	250	250	250
BARIUM COMPOUNDS (TRI Chemical ID: N040)	DISP NON METALS	Pounds	357237	415333	538043	505000	520000	600000	490000	510000	510000	410000	460000	300000	300000
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	AIR FUG	Pounds	NR	1	1	NR	NR	NR	1	.6	NR	NR	NR	NR	NR
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	AIR STACK	Pounds	NR	26	19	NR	NR	NR	9	5	NR	NR	NR	NR	NR
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	DISP NON METALS	Pounds	NR	27282	21125	NR	NR	NR	9319	5450	NR	NR	NR	NR	NR
DIOXIN AND DIOXIN-LIKE COMPOUNDS (TRI Chemical ID: N150)	AIR STACK	Grams	1.38	1.499	1.47	.79	.7	.8	.7	.79	.71	.75	.71	NR	NR
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	AIR STACK	Pounds	6335	9823	8019	22000	8900	11000	8800	19000	17000	30000	20000	18000	14000

(TRI Chemical ID: 007647010)															
HYDROGEN FLUORIDE (TRI Chemical ID: 007664393)	AIR STACK	Pounds	85383	119664	95712	43000	92000	88000	57000	72000	81000	84000	83000	71000	70000
LEAD COMPOUNDS (TRI Chemical ID: N420)	AIR FUG	Pounds	.32	.56	.31	.7	.4	.3	.3	.4	.6	.3	NR	NR	NR
LEAD COMPOUNDS (TRI Chemical ID: N420)	AIR STACK	Pounds	7.8	14	7.84	17.8	11	8.4	7.2	9.4	14.3	8.9	NR	NR	NR
LEAD COMPOUNDS (TRI Chemical ID: N420)	DISP NON METALS	Pounds	7928	14169	8132	18500	11400	8700	6800	9581.1	14472.3	8602.2	NR	NR	NR
LEAD COMPOUNDS (TRI Chemical ID: N420)	SI 5.5.3B	Pounds	.1	0	.05	.08	.07	.06	.14	0	NR	NR	NR	NR	NR
LEAD COMPOUNDS (TRI Chemical ID: N420)	WATER	Pounds	0	0	0	0	0	0	0	.1	0	0	NR	NR	NR
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	AIR FUG	Pounds	0	1	2	1	1	2	1	1	5	5	0	5	5
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	AIR STACK	Pounds	13	13	12	16	14	42	15	13	5	5	5	250	250
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	DISP NON METALS	Pounds	12210	13853	14101	19012	16021	50015	17027	15250	11250	12250	12250	19250	19250
MERCURY (TRI Chemical ID: 007439976)	AIR FUG	Pounds	0	0	0	0	.001	0	0	0	0	0	NR	NR	NR
MERCURY (TRI Chemical ID:	AIR STACK	Pounds	10.9	26.22	22	30	19.2	17.5	5.4	18.1	17.2	19.6	NR	NR	NR

007439976)															
MERCURY (TRI Chemical ID: 007439976)	DISP NON METALS	Pounds	28.6	68.89	58	78.8	50	45.7	13.3	47.4	44.6	50.3	NR	NR	NR
MERCURY (TRI Chemical ID: 007439976)	SI 5.5.3B	Pounds	0	0	.03	.05	.04	.03	.1	0	NR	NR	NR	NR	NR
MERCURY (TRI Chemical ID: 007439976)	WATER	Pounds	0	.1	0	0	0	0	0	0	0	0	NR	NR	NR
MERCURY COMPOUNDS (TRI Chemical ID: N458)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	18	NR	NR
MERCURY COMPOUNDS (TRI Chemical ID: N458)	DISP NON METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	48.1	NR	NR
MERCURY COMPOUNDS (TRI Chemical ID: N458)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	.2	NR	NR
NICKEL COMPOUNDS (TRI Chemical ID: N495)	AIR FUG	Pounds	.2	.6	.7	.4	.3	.3	0	0	5	5	0	0	NR
NICKEL COMPOUNDS (TRI Chemical ID: N495)	AIR STACK	Pounds	4.3	14.4	12	8	4.8	4	5	4	5	5	5	5	NR
NICKEL COMPOUNDS (TRI Chemical ID: N495)	DISP NON METALS	Pounds	4078	14939	14503	9642	5760	4852	5476	4250	5450	6850	2350	2750	NR
SULFURIC ACID (1994 AND AFTER "ACID AEROSOLS" ONLY) (TRI Chemical ID: 007664939)	AIR STACK	Pounds	NR	21489	25040	25000	NR	25000	NR	24000	23000	16000	NR	NR	NR

VANADIUM COMPOUNDS (TRI Chemical ID: N770)	AIR FUG	Pounds	.7	.7	NR	.8	.7	.6	1	NR	5	5	NR	NR	NR
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	AIR STACK	Pounds	17	17.5	NR	20	16	15	16	NR	250	250	NR	NR	NR
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	DISP NON METALS	Pounds	17274	17661	NR	22000	17300	16000	16000	NR	20000	31000	NR	NR	NR
ZINC COMPOUNDS (TRI Chemical ID: N982)	AIR FUG	Pounds	NR	NR	NR	.7	1.1	1	NR	1	NR	NR	NR	NR	NR
ZINC COMPOUNDS (TRI Chemical ID: N982)	AIR STACK	Pounds	NR	NR	NR	23	32	33	NR	36	NR	NR	NR	NR	NR
ZINC COMPOUNDS (TRI Chemical ID: N982)	DISP NON METALS	Pounds	NR	NR	NR	20000	29600	30000	NR	31000	NR	NR	NR	NR	NR

Discharge of Chemicals into Streams or Bodies of Water:

For all releases estimated as a range, the mid-point of the range was used in these calculations. Rows with Release Amount equal to "0" were not listed.

Chemical Name	Year	Unit Of Measure	Release Amount	Stream Or Body of Water
LEAD COMPOUNDS (TRI Chemical ID: N420)	2003	Pounds	.1	FOUNTAIN CREEK
MERCURY (TRI Chemical ID: 007439976)	2009	Pounds	.1	FOUNTAIN CREEK

Transfer of Chemicals to Off-Site Locations other than POTWs:

Please note that transfer amounts are not included in release totals shown above. For all releases estimated as a range, the mid-point of the range was used in these calculations. Rows with Total Transfer Amount equal to "0" were not listed.

Chemical Name	Year	Unit Of Measure	Total Transfer Amount	Transfer Site Name and Address	Type Of Waste Management
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2010	Pounds	7	WASTE MANAGEMENT COLORADO SPRINGS LANDFILL 13320 E. HIGHWAY 94 COLORADO SPRINGS, CO 80929	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2010	Pounds	357230	RAY NIXON POWER PLANT 6598 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2009	Pounds	1	WASTE MANAGEMENT COLORADO SPRINGS LANDFILL 13320 E. HIGHWAY 94 COLORADO SPRINGS, CO 80929	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2009	Pounds	415332	RAY NIXON POWER PLANT 6598 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2008	Pounds	538043	RAY NIXON POWER PLANT 6598 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2007	Pounds	505000	RAY NIXON POWER PLANT 14020 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2006	Pounds	520000	RAY NIXON POWER PLANT 14020 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2005	Pounds	600000	RAY NIXON POWER PLANT 14020 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2004	Pounds	490000	RAY NIXON POWER PLANT 14020 RAY NIXON ROAD FOUNTAIN, CO 80817	Other Landfills

Summary of Waste Management Activities

Please note that chemical amounts shown here are not included in Total Aggregate Releases shown above.

Summary of Waste Management Activities excluding Dioxin and Dioxin-like Compounds (Measured in Pounds)

Year	On-Site Recycling	Off-Site Recycling	On-Site Energy Recovery	Off-Site Energy Recovery	On-Site Treatment	Off-Site Treatment	Total Amount
2009	0	0	0	0	100251	0	100251
2010	0	0	0	0	72321	0	72321
2011 (Projected)	0	0	0	0	72321	0	72321
2012 (Projected)	0	0	0	0	67982	0	67982

Summary of Waste Management Activities for Dioxin and Dioxin-like Compounds (Measured in Grams)

This facility did not report any waste management activities for Dioxin and Dioxin-like Compounds.

Chemicals Under Waste Management:

Please note that chemical amounts shown here are not included in the Total Aggregate Releases shown above. Transfers to Publicly Owned Treatment Works are listed on a seperate table.

Chemical Name	Year	Unit Of Measure	On-Site Recycling	Off-Site Recycling	On-Site Energy Recovery	Off-Site Energy Recovery	On-Site Treated	Off-Site Treated	Total Amount
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	2009	Pounds	0	0	0	0	36681	0	36681
	2010	Pounds	0	0	0	0	24334	0	24334
	2011 (Projected)	Pounds	0	0	0	0	24334	0	24334
	2012 (Projected)	Pounds	0	0	0	0	22874	0	22874
HYDROGEN FLUORIDE	2009	Pounds	0	0	0	0	63570	0	63570
	2010	Pounds	0	0	0	0	47987	0	47987
	2011 (Projected)	Pounds	0	0	0	0	47987	0	47987
	2012 (Projected)	Pounds	0	0	0	0	45108	0	45108

Transfer of Chemicals to Publicly Owned Treatment Works (POTW):

Please note that transfer amounts are not included in the Total Aggregate Releases shown above. For all releases estimated as a range, the mid-point of the range was used in these calculations.

Chemical Name	Year	Unit Of Measure	Total Transfer Amount
BARIUM COMPOUNDS	1998	Pounds	250
BARIUM COMPOUNDS	1999	Pounds	250
BARIUM COMPOUNDS	2000	Pounds	250
BARIUM COMPOUNDS	2001	Pounds	250
BARIUM COMPOUNDS	2002	Pounds	250
BARIUM COMPOUNDS	2003	Pounds	119
BARIUM COMPOUNDS	2004	Pounds	126
BARIUM COMPOUNDS	2005	Pounds	188
BARIUM COMPOUNDS	2006	Pounds	253
BARIUM COMPOUNDS	2007	Pounds	215
BARIUM COMPOUNDS	2008	Pounds	211
BARIUM COMPOUNDS	2009	Pounds	180
BARIUM COMPOUNDS	2010	Pounds	230
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2003	Pounds	7
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2004	Pounds	8
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2008	Pounds	13
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2009	Pounds	11
LEAD COMPOUNDS	2001	Pounds	6.7
LEAD COMPOUNDS	2002	Pounds	8.6
LEAD COMPOUNDS	2003	Pounds	7.4
LEAD COMPOUNDS	2004	Pounds	7.9
LEAD COMPOUNDS	2005	Pounds	11.8
LEAD COMPOUNDS	2006	Pounds	15.9
LEAD COMPOUNDS	2007	Pounds	13.5
LEAD COMPOUNDS	2008	Pounds	13.23
LEAD COMPOUNDS	2009	Pounds	11.3

LEAD COMPOUNDS	2010	Pounds	14.4
MANGANESE COMPOUNDS	1998	Pounds	250
MANGANESE COMPOUNDS	1999	Pounds	250
MANGANESE COMPOUNDS	2000	Pounds	250
MANGANESE COMPOUNDS	2001	Pounds	250
MANGANESE COMPOUNDS	2002	Pounds	250
MANGANESE COMPOUNDS	2003	Pounds	127
MANGANESE COMPOUNDS	2004	Pounds	140
MANGANESE COMPOUNDS	2005	Pounds	200
MANGANESE COMPOUNDS	2006	Pounds	270
MANGANESE COMPOUNDS	2007	Pounds	230
MANGANESE COMPOUNDS	2008	Pounds	225
MANGANESE COMPOUNDS	2009	Pounds	192
MANGANESE COMPOUNDS	2010	Pounds	246
MERCURY	2001	Pounds	.2
MERCURY	2002	Pounds	.3
MERCURY	2003	Pounds	.2
MERCURY	2004	Pounds	.3
MERCURY	2005	Pounds	.4
MERCURY	2006	Pounds	.5
MERCURY	2007	Pounds	.4
MERCURY	2008	Pounds	.4
MERCURY	2009	Pounds	.36
MERCURY	2010	Pounds	.5
MERCURY COMPOUNDS	2000	Pounds	.2
NICKEL COMPOUNDS	1999	Pounds	250
NICKEL COMPOUNDS	2000	Pounds	250
NICKEL COMPOUNDS	2001	Pounds	250
NICKEL COMPOUNDS	2002	Pounds	27
NICKEL COMPOUNDS	2003	Pounds	23
NICKEL COMPOUNDS	2004	Pounds	25

NICKEL COMPOUNDS	2005	Pounds	37
NICKEL COMPOUNDS	2006	Pounds	50
NICKEL COMPOUNDS	2007	Pounds	42
NICKEL COMPOUNDS	2008	Pounds	42
NICKEL COMPOUNDS	2009	Pounds	35
NICKEL COMPOUNDS	2010	Pounds	45
VANADIUM COMPOUNDS	2001	Pounds	250
VANADIUM COMPOUNDS	2002	Pounds	250
VANADIUM COMPOUNDS	2004	Pounds	61
VANADIUM COMPOUNDS	2005	Pounds	91
VANADIUM COMPOUNDS	2006	Pounds	120
VANADIUM COMPOUNDS	2007	Pounds	100
VANADIUM COMPOUNDS	2009	Pounds	88
VANADIUM COMPOUNDS	2010	Pounds	112
ZINC COMPOUNDS	2003	Pounds	71
ZINC COMPOUNDS	2005	Pounds	113
ZINC COMPOUNDS	2006	Pounds	150
ZINC COMPOUNDS	2007	Pounds	129

Publicly Owned Treatment Works (POTW) that Chemicals were Transferred to:

Chemical Name	Year	POTW Name and Address
BARIUM COMPOUNDS	1998	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 EAST LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	1999	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2000	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT

		703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2001	COLORADO SPRINGS UTILITIES WAS TEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2001	NA ,
BARIUM COMPOUNDS	2002	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2003	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2004	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2005	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 EAST LAS VEGAS COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2006	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2007	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906

BARIUM COMPOUNDS	2008	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2009	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
BARIUM COMPOUNDS	2010	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2003	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2004	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E LAS VEGAS COLORADO SPRINGS, CO 80906
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2008	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2009	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
DIOXIN AND DIOXIN-LIKE COMPOUNDS	2000	NA ,
DIOXIN AND DIOXIN-LIKE COMPOUNDS	2001	NA ,

DIOXIN AND DIOXIN-LIKE COMPOUNDS	2002	NA ,
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	1998	NA ,
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	1999	NA ,
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	2000	NA ,
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	2001	NA ,
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	2002	NA ,
HYDROGEN FLUORIDE	1998	NA ,
HYDROGEN FLUORIDE	1999	NA ,
HYDROGEN FLUORIDE	2000	NA ,
HYDROGEN FLUORIDE	2001	NA ,
HYDROGEN FLUORIDE	2002	NA ,
LEAD COMPOUNDS	2001	COLORADO SPRINGS UTILITIES WAS TEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2002	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS

		COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2003	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2004	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E LAS VEGAS COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2005	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 EAST LAS VEGAS COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2006	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2007	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2008	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2009	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906
LEAD COMPOUNDS	2010	COLORADO SPRINGS UTILITIES WASTEWATER TREATMENT PLANT 703 E. LAS VEGAS STREET COLORADO SPRINGS, CO 80906

Non-Production Releases:

This facility did not report any Non-Production releases.

Additional links for TRI:

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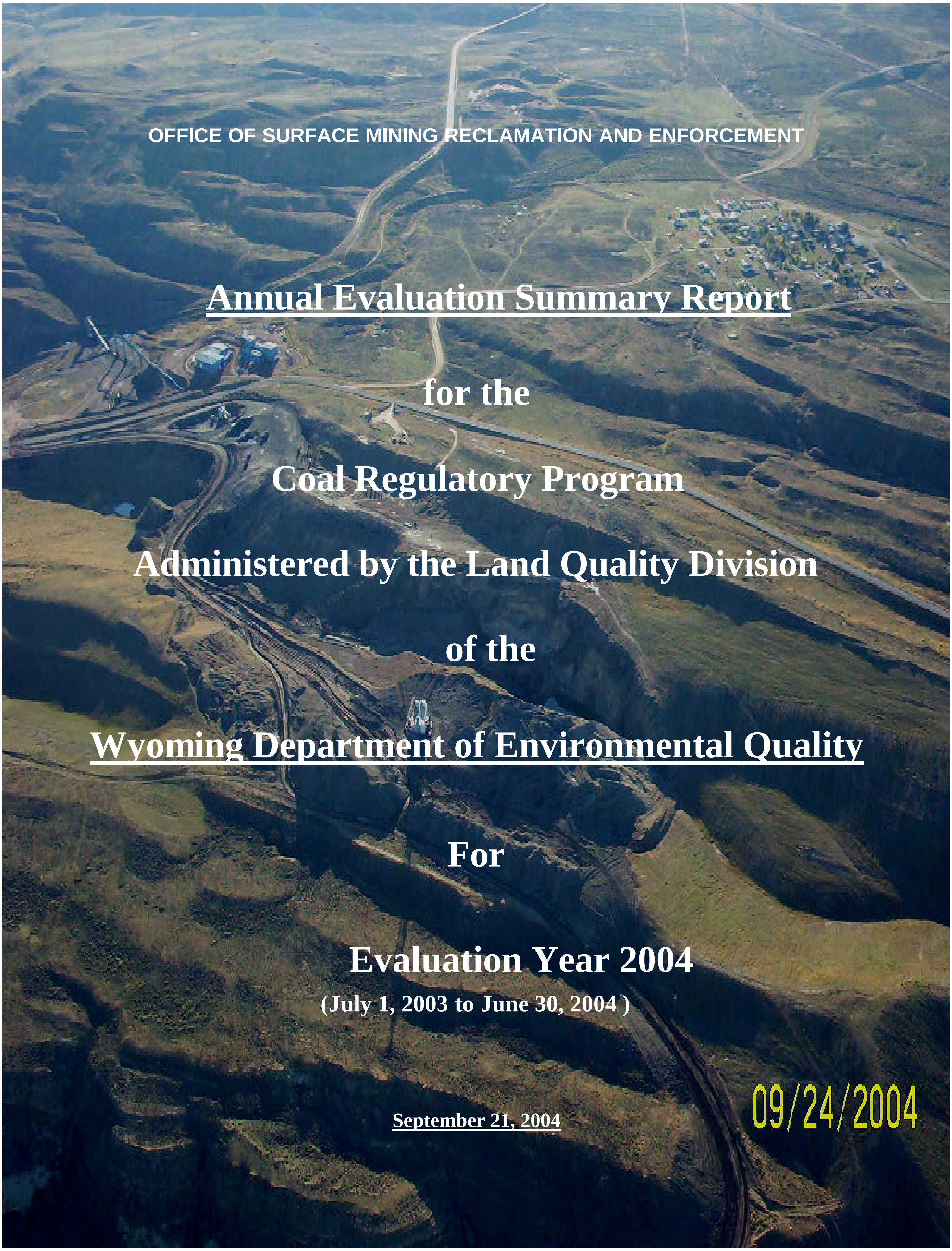
Exhibit 16

OSMRE, Wyoming Annual Oversight Report (2004)



OFFICE OF SURFACE MINING RECLAMATION AND ENFORCEMENT

Annual Evaluation Summary Report

for the

Coal Regulatory Program

Administered by the Land Quality Division

of the

Wyoming Department of Environmental Quality

For

Evaluation Year 2004

(July 1, 2003 to June 30, 2004)

September 21, 2004

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Appendix A: Tabular Summary of Core Data to Characterize the Program

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Appendix C: CFO Responses to State Comments

I. Introduction

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) created the Office of Surface Mining Reclamation and Enforcement (OSM) in the Department of the Interior. SMCRA provides authority to OSM to oversee the implementation of and provide Federal funding for State regulatory programs that have been approved by OSM as meeting the minimum standards specified by SMCRA. This report contains summary information regarding the Wyoming Program and the effectiveness of the Wyoming program in meeting the applicable purposes of SMCRA as specified in section 102. The report covers the period of July 1, 2003 thru June 30, 2004. Detailed background information and comprehensive reports for the program elements evaluated during the period are available for review and copying at the Casper Field Office.

The following list of acronyms is used in this report:

ACHP	Advisory Council on Historic Preservation
AQD	Air Quality Division
BLM	Bureau of Land Management
CFO	Casper Field Office
DEQ	Department of Environmental Quality
EQC	Environmental Quality Council
EY	Evaluation Year
LQD	Land Quality Division
MIER	Mine Inspection Evaluation Report
NOV	Notice of Violation
NOx	Nitrogen oxides
NTTP	National Technical Training Program
OSM	Office of Surface Mining Reclamation and Enforcement
OTT	Office of Technical Transfer
PRBRC	Powder River Basin Resource Council
RSI	Random Sample Inspection
SHPO	State Historic Preservation Office
SMCRA	Surface Mining Control and Reclamation Act of 1977
TDN	Ten-Day Notice
TIPS	Technical Information Processing Systems
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
WQD	Water Quality Division
WRCC	Western Regional Coordinating Center
WOC	Wyoming Outdoor Council
WWF	Wyoming Wildlife Federation

II. Overview of the Wyoming Coal Mining Industry

Wyoming is the top coal producing state in the nation. Table 1 shows the past three years' coal production for Wyoming. Over ninety-nine percent of the current coal production in Wyoming is from surface coal mines and 92 percent of all coal produced is being mined in the Powder

River Coal Basin near Gillette, Wyoming. Until 1954, underground mines out-produced surface mines, but in that year surface mines began to dominate production. By the late 1970's, surface coal mining production in the Powder River Basin became a major contributor to the Nation's total coal production. Coal-bearing formations underlie more than 40,000 square miles, or approximately 41 percent of Wyoming's total land area. The coal mining industry directly employs approximately 4,788 people providing substantial income and secondary employment in the State. Approximately 97 percent of coal produced in Wyoming is used for electrical generation in 37 states, Canada and Spain. Coal production increased 1 percent in the last year and over 10 percent in the past 4 years.

The Wyoming Geological Survey estimates the quantity of Wyoming open pit coal reserves is in excess of 26.3 billion tons; an additional 38.3 billion tons of coal reserves can be recovered by underground mining methods. Coal seams in the Wasatch Formation and the underlying Fort Union Formations can exceed 100 feet in thickness with 30 to 80 foot seams being common; 220 foot thick seams have been uncovered. Wyoming coals range from lignite to high volatile A bituminous in rank with the majority of the coal produced being sub-bituminous. Wyoming has the largest reserves of "compliance coal" in the lower 48 States; that is coal of such high quality that utility companies can burn the coal in power plants without expensive scrubbers to remove sulphur dioxide emissions. Currently, over 7 billion tons of coal is leased and 345,570 acres are permitted (Table 2).

Thirty-five active mining operations are permitted in Wyoming; 31 are surface operations, two (2) are underground operation, one permit for a dragline move from one mine site to another and one in-situ operation. The dragline move and in-situ operations are listed as “other facilities” in Table 2 of this report. Currently, twenty mines of the thirty-five permitted operations are producing coal. Four mines are in temporary cessation, and nine mines and two “other facilities” are conducting final reclamation. Table 3 shows the permitting activity for the past twelve month evaluation period.

III. Overview of the Public Participation Opportunities in the Oversight Process and the State Program

A. OSM Outreach Efforts

The Casper Field Office (CFO) actively encourages public involvement in the Wyoming oversight and regulatory program. This includes CFO initiated contacts with citizen groups and participation in industry activities. Specifically, CFO has visited with citizens representing the Powder River Basin Resource Council (PRBRC), Wyoming Outdoor Council (WOC), Wyoming Wildlife Federation (WWF), and the Wyoming Mining Association (WMA). The purpose of these contacts is to notify these groups of OSM’s activities and to provide the opportunity to interested parties to suggest how OSM’s oversight role can assist in improving the State’s regulatory program. In the past, CFO held public meetings; however, there was very limited public participation.

CFO has a good working relationship with the PRBRC, WOC and WWF. These organizations are actively involved in OSM and State permitting and inspection oversight activities. Such involvement has resulted in helpful changes in the State program, thus improving the overall quality of the program. PRBRC has taken an active part in the oversight process and meets with the CFO a couple times a year. PRBRC and WOC have been focused more on coalbed methane and natural gas development and less on coal. WWF have been less actively in coal mining issues for several years. CFO maintains communications with these groups, informing them of meetings and issues and offering opportunities to participate in meetings.

B. Wyoming Outreach Efforts

LQD has an advisory board (Land Quality Division Advisory Board) that provides recommendations to the Land Quality Division through a public forum. The Environmental Quality Council (EQC) rules on regulatory matters for all Divisions within the Department (including LQD), and also serves as the administrative hearings board for all Divisions (i.e., Land Quality, Air Quality and Water Quality Divisions) in DEQ. Wyoming's outreach efforts include, but are not limited to LQD Advisory Board meetings, and Environmental Quality Council hearings and public meetings. LQD has met on several occasions with the special interest groups (PRBRC, WOC, WWF, and WMA) to discuss their concerns. In addition, LQD has hosted several technical forums addressing current issues.

LQD is also involved its own public participation program during their permitting, bond release, and enforcement processes. During the permitting and bond release processes, notices are published and comments are solicited. Citizen complaints are investigated as part of the enforcement process. Previous oversight reviews have found that LQD is highly receptive to the concerns of public, industry and citizen groups. DEQ also has an internet website at: http://deq.state.wy.us/ with information for the public on permits, current rules, proposed rule changes and contact information.

CFO monitors DEQ's and LQD's meetings and outreach efforts and believes the State does a good job interacting with citizens.

IV. Major Accomplishments/Issues/Innovations in the Wyoming Program

A. Accomplishments

Although the State has not addressed all the outstanding regulatory program deficiencies, the State of Wyoming continues to administer an excellent Title V program (See VII. General Oversight Topic Reviews, B. Monitoring, Program Maintenance). Wyoming actively works to improve its program. Wyoming has taken the initiative to conduct a pilot study to determine the feasibility of using GPS and GIS in tracking and documenting bond release areas (see section **C.** below).

The Wyoming Department of Environmental Quality, Land Quality Division (LQD) has addressed the majority of the outstanding program deficiencies. LQD has submitted and received approval for four program amendments since 1995. There are six remaining program amendments addressing 36 program deficiencies. Two amendments have been submitted to OSM for review, and one amendment is in the final stages of the State's rulemaking process. One of the remaining amendment packages contains "Ownership & Control rules" (18 deficiencies). WRCC has suggested that LQD delay working on these rules to the last, due to OSM's current rule litigation relating to the valid existing rights, and ownership and control rules.

OSM is currently reviewing program amendment 1-R (Highwall Retention and Coal Exploration) when approved could eliminate another 8 program deficiencies if approved by OSM during the next evaluation period.

B. Issues

1. Cooperative Agreement

On December 7, 1999, CFO hosted a forum to discuss Federal land coordination which included participants from four BLM and three LQD offices, the U.S. Forest Service (USFS), WRCC, and CFO. A work group was assembled to establish a Working Agreement under the Wyoming Cooperative Agreement.

The group developed a document outlining the coordination between the LQD and the Federal agencies including the procedures for coordinating between LQD, USFS, BLM and OSM as it relates to each agency's area of responsibilities. During the evaluation period, there have been three meetings with LQD, BLM, USFS and OSM personnel. The intent of the meetings was to discuss and clarify the implementation of the agreement. Thus far, the procedure for this agreement appear to be working and opening lines of communications among the agencies that had not occurred in the past.

2. Fugitive Dust

In the past 5 years, the Powder River Basin has experienced air quality problems cited by the EPA. A large portion of this air quality problem can be attributed to fugitive dust. During this time, the expansion of coalbed methane development in the Powder River basin quadrupled. The coalbed methane industry is not as strictly regulated as the coal mining industry, yet in many cases, existing adjacent to each other. If the air quality issue is not resolved, EPA may prohibit further expansion in the basin. State, county and both the coalbed methane and coal mining industries are working to reducing the fugitive dust and other pollutants in the Powder River Basin.

During the September OSM overflight inspection, fugitive dust was noted coming from the South Pit at the Black Thunder

C. Innovations

LQD with the assistance of OSM's WRCC and support of the Powder River Basin Coal Company's (PRBCC) North Antelope/Rochelle, and Caballo mines have initiated a GIS/GPS pilot study. The purpose of the study is to determine the feasibility of using GPS in the field and integrating the data into a GIS data bank to track reclaimed lands and bond releases. The agreement among the LQD, OSM and Powder River Basin Coal Company was signed including the North Antelope/Rochelle mine complex and Caballo mines in the GIS/GPS project. The software and hardware installation and field work began in June 2003. As part of this effort OSM provided GPS and GIS training.

In September 2003. OSM held an "Intro To ArcGIS for Mining" course. Twelve people attended from LQD and PRBCC. In addition, WRCC specialists provided on-site training in GIS for LDQ's Cheyenne and Sheridan offices, and worked throughout year on designing and geoprocessing data into the Wyoming GIS Bonding database.

Photo of smoke from coal fires at the North Antelope/Rochelle mine complex observed during an OSM oversight flight in 2003.

V. Success in Achieving the Purposes of SMCRA as Determined by Measuring and Reporting End Results

To further the concept of reporting "end results," the findings from performance standards and public participation evaluations are being collected for a national perspective in terms of the number and extent of observed off-site impacts, the number of acres that have been mined and reclaimed and which meet the bond release requirements for the various phases of reclamation, and the effectiveness of customer service provided by the State. Individual topic reports are available in the Casper Field Office providing additional details on how the following evaluations and measurements were conducted.

A. Off-Site Impacts

For the purpose of oversight, an off-site impact is defined as anything resulting from a surface coal mining and reclamation activity or operation that causes a negative effect on people, land, water, or structures outside the permit. The impact on the resource must be substantiated as being related to a mining and reclamation activity, and must be outside the area authorized by the permit for conducting mining and reclamation activities.

During the evaluation period, LQD conducted 142 complete inspections and 251 partial inspections resulting in 7 Notices of Violation (NOVs) and no Cessation Orders (COs) being issued. CFO reviewed state inspection reports to determine if off-site impacts occurred. In addition, CFO conducted twenty-one total inspections, all of which were partial / focused inspections of coal mining operations in Wyoming (MIER). CFO did not conduct any complete inspections.

Table 4 reflects that there were two off-site impacts; one hydrology impacted observed by OSM; and one blasting violation documented by the State.

B. Bond Release

Wyoming LQD completed 14 bond release actions during this evaluation period. There was one Phase I release of 6,550 acres, and no Phase II or III releases (Table 5).

Reclamation bonds have become more difficult to acquire for mining companies, yet there is no noticeable increase in bond release applications. Instead, the mining industry appears to be attempting to change the performance requirements for bond. Only two coal companies have applied for all or portion of the three phases of bond release. Very few companies have even applied for the initial Phase I release. Instead, nearly every year the coal companies apply for bond release on area bonds, which includes the active mining pit and the rough backfilled spoils. The area bond then is applied to the current and projected mining pit are for the next year. (see the discussion below).

OSM evaluates the effectiveness of the Wyoming program based on the number of acres that meet bond release standards and have received bond release (Tables 5 and 6). The CFO believes this measure may not capture the total effectiveness of the Wyoming program due to the type of mining operations, the large size of western mining operations and company policies (not to apply for release until large management units are eligible for final bond release). The number of acres released from bond is relatively small in Wyoming when compared to those acres that have been graded, topsoiled and revegetated. Currently in Wyoming approximately 110,578 acres have been disturbed, 38,498 acres have been backfilled and graded and of those acres 13,267 acres have received Phase I release, 1,282 acres Phase II release and 876 acres Phase III released. Also, records indicate at least 8,086 acres have been reclaimed for a minimum of 10 years and may be eligible for full Phase III release. As defined by OSM Directive REG-8 (Oversight of State Regulatory Programs) it appears that the Wyoming program is not effective in facilitating and encouraging bond release, as indicated by the small number of acres released from bond, compared to the large quantity of acreage available for release.

The Wyoming coal regulatory program has an approved alternative bonding system, differing from Federal and other State coal regulatory programs. Wyoming's bonding system consists of an "area bond" and an "incremental bond." The area bond moves each year with the pit progression, which is adjusted through the submission and review of the permit annual report. The incremental bond covers the entire permit area.

There were no bond forfeitures during the past three years. There have been only two bond forfeitures since the approval of the Wyoming program in 1981. Those two bond forfeitures were for two underground mines. None of the large surface coal mines have experienced any bond forfeitures.

C. Reclamation Success and Program Performance

OSM evaluates and reports annually on the effectiveness of State programs in ensuring successful reclamation on lands affected by surface coal mining operations. Success is determined based on the number of acres that meet the bond release standards and have been released by the State. In addition, Field Offices conduct specific evaluations to evaluate the State's performance.

Using the number of acres released from bonds as the criteria, the Wyoming program has not achieved a large amount of reclamation success. However, as described above, bond release may not accurately reflect the performance of the program. Tables 5 and 6 summarize reclamation activity within the State.

Information was collected to measure program performance in the following areas four performance areas.

1. <u>Reclamation Success As Measured By Bond Release</u>

Backfilling and grading achievements are measured by the acres of phase I bond release as required by OSM Directive REG-8, p.I-9. This is depicted in Chart 1. Only about 33 percent of the lands that have been backfilled and graded to the approved postmine topography/approximate original contour and topsoiled have received Phase I bond release.

The proper placement of soil resources and vegetation stability are measured by the acres released under Phase I and II release (REG-8, p I-10). About 36 percent of the lands have been topsoiled and received Phase I bond release. While about 4 percent of the lands have been revegetated and received Phase II bond release.

The success of postmining land use, successful revegetation, and the restoration of surface and ground water quality and quantity are measured by the acres of Phase III bond release (REG-8, pp. I-11-12). Only about 11 percent of the lands have been successful revegetated for at least 10 years and received Phase III final bond release.

Chart 1. Bond Release –as a Measurement of Reclamation Success

Measurement of Reclamation Success	Acres available for bond release	Acres of Area Bonds Release and %	Acres of Bond Released		
			Phase I / %	Phase II & %	Phase III & %
Backfill & Grade	**40,826**	**13,267 / 32.5%**	**NA**	**NA**	**NA**
Soil Replacement	**36,966**		**13,267/ 35.9%**	**NA**	**NA**
Revegetation	**36,966**			**1,282 / 3.5%**	**NA**
Achieve Postmining Use, Hydrologic Reclamation, and Timelineness of Reclamtion	**8,086**				**876 / 10.8%**

As mentioned previously, the measure of reclamation success solely by bond release does not accurately reflect the total effectiveness or success of the coal regulatory program. CFO believes that monitoring the progress of on-going reclamation in relation to the mining progression is a better measure of the effectiveness and success of a reclamation program.

CFO will continue reviewing the permit annual reports during the next evaluation period to determine the acres that have been rough backfilled and those area bonds have progressed onto newly disturbed areas. Such areas are considered eligible for Phase I bond releases after final grading is completed under the Wyoming program. The State and CFO encourage companies to apply for bond releases. However, economic pressures from the increase cost of bonds maybe the only way to achieve a higher number of bond releases.

2. Program Performance

a. Contemporaneous Reclamation

While contemporaneous reclamation is not reflected by bond releases as depicted in Table 5, it is the intent of SMCRA to assure that adequate procedures are undertaken to reclaim surface areas as contemporaneously as possible on the ground. Table 6 provides an overall perspective of the relationship between disturbance and reclamation. Chart 2 and Graph 1 further depict this relationship, while Graph 2 illustrates the cumulative relationship between disturbance verse reclamation of lands.

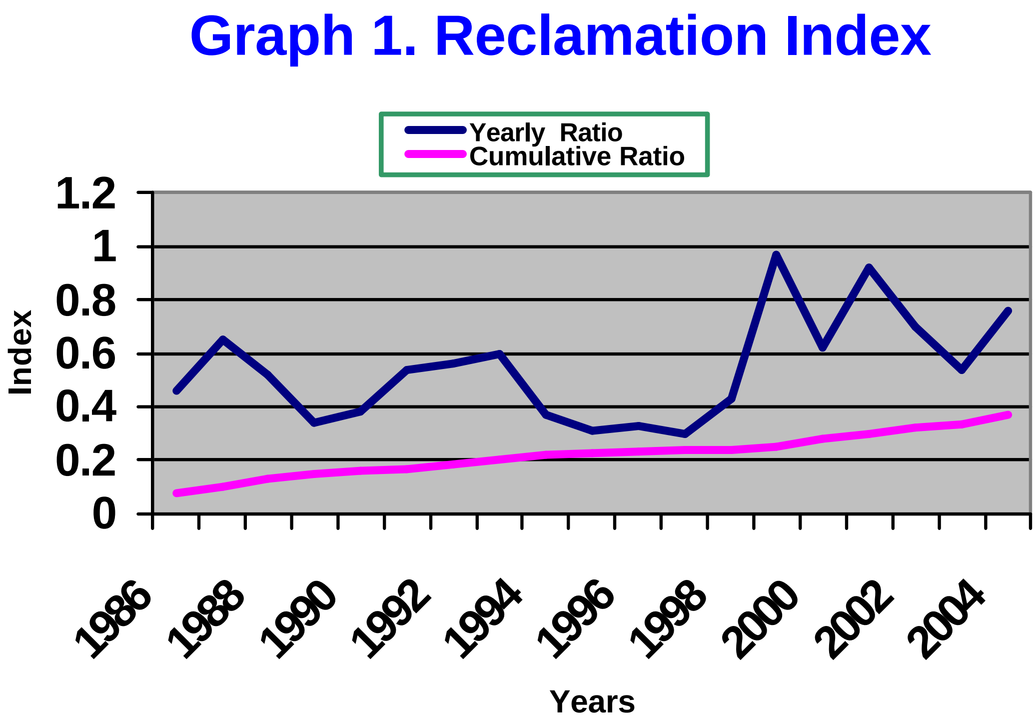
The intent of contemporaneous reclamation is to provide a balance between disturbance and reclamation and an overall picture of the success of reclamation is keeping step with the mining progression in the State. Information provided to complete Table 5 and Table 6 in the annual reports summarizes mining and reclamation activity and should be considered a source for this measurement.

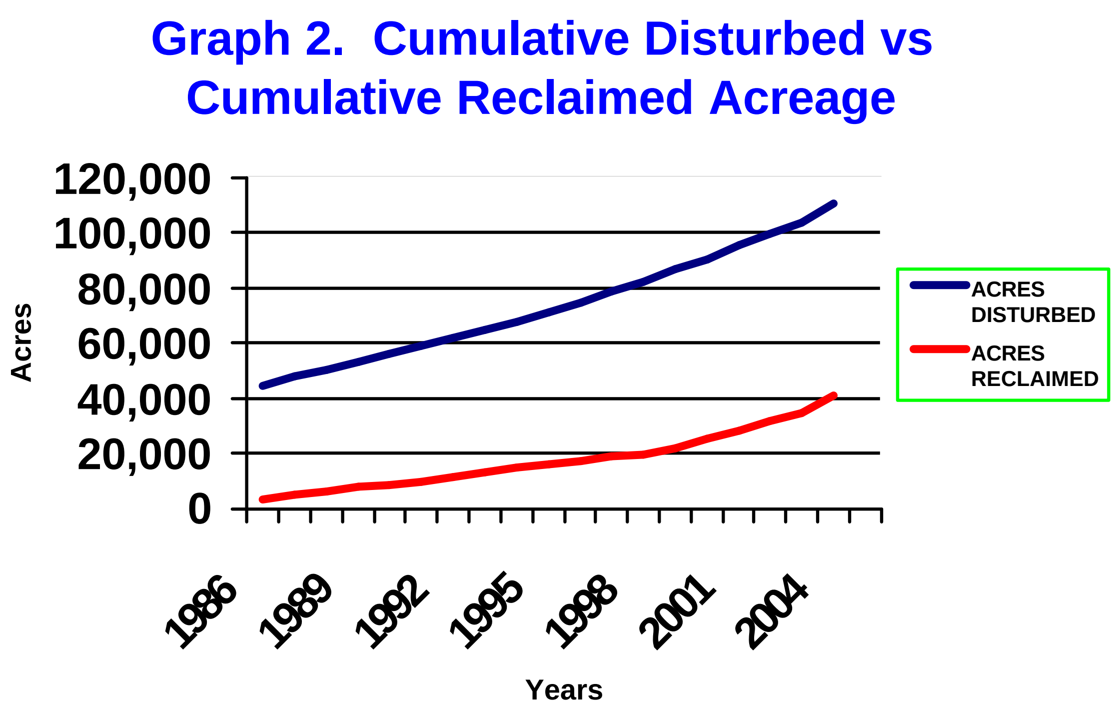
The following charts and graphs are used to highlight the CFO's concern that the rate at which lands are being reclaimed in Wyoming compared to the rate of disturbance. Currently the ratio is about 3 to 1 and has been improving over the years. Ideally the ratio should be 1 to 1 as mentioned below. The gap between the acres disturbed verses reclaimed is widening, thereby creating a backlog of lands available for reclamation, contributing to a delay in contemporaneous reclamation and subsequent bond release.

Chart 2. WYOMING STATEWIDE RECLAMATION SUMMARRY

YEAR	**ACRES DISTURBED**	**Cumulative Acres Dist.**	**ACRES RECLAIMED**	**Cumulative Acres Recl.**	**RATIO OF RECLAM VS DISTURB**	**Cumulative RATIO OF RECLAM VS DISTURB**
1986	3152	44,742	1456	3,335	.46	.075
1987	2521	47,894	1630	4,791	.65	.100
1988	2610	50,415	1355	6,421	.52	.127
1989	2967	53,025	994	7,776	.34	.147
1990	2833	55,992	1068	8,770	.38	.157
1991	2807	58,825	1517	9,838	.54	.167
1992	2919	61,632	1641	11,355	.56	.184
1993	3173	64,551	1888	12,996	.60	.201
1994	3327	67,724	1219	14,884	.37	.220
1995	3873	71,051	1234	16,103	.31	.227
1996	3954	74,924	1311	17,337	.33	.231
1997	3613	78,878	1098	18,648	.30	.236
1998	4303	82491	1973	19,746	.43	.239
1999	3868	86,794	3541	21,719	.97	.250
2000	5185	90,662	3174	25,260	.62	.279
2001	3564	95,847	3295	28,434	.92	.297
2002	4067	99,411	2857	31,729	.70	.319
2003	5459	103,478	2924	34,653	.54	.335
2004	5062	110,578	3843	40,826	.76	.392

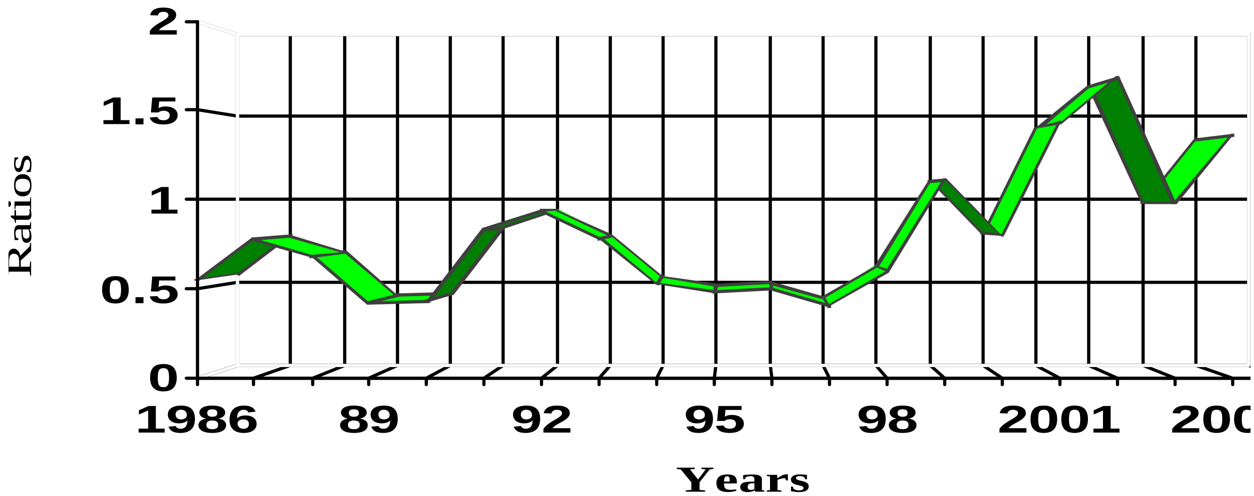
Total acres disturbed equaled 110,578 and total acres reclaimed equaled 40,826 for a Ratio of .392 on a statewide basis.





Approximately 345,570 acres are currently bonded (Table 5). During the evaluation period, an additional 3,843 acres were permanently reclaimed with a permanent seed mixture. Approximately, 35,000 acres are ready for Phase I and Phase II bond release. Table 6 depicts data collect from 1986 to 2004, giving a long term view of the mining and reclamation activities in Wyoming.

Graph 3. Reclamtion Ratios



Graph 3. is similar to Graph 1., except this graph acknowledges that some facilities are necessary to operate the mine can not be reclaimed until mining is completed. Graph 3. illustrates the ratio of the yearly permanent reclamation compared with the net disturbance found in Table 6. Net disturbance consists of areas available for reclamation that are not being used for long-term approved disturbances such as: stockpiles, active pits, access roads, haul roads, railroad right-of-ways, coal preparation and loading sites, offices, shops, sediment ponds, and other approved uses. The 2004 ratio shows a 31 percent increase of reclamation, as well as, a 6.8 percent increase of newly disturbed lands. Approximately 49 percent of the newly disturbed lands were for long-term facilities. The ratio of reclamation to net disturbance for EY 2004 is 1.36. A ratio of 1.0 indicates that the reclamation and net disturbance are equal. A ratio higher than 1.0 indicates that the reclamation is greater than the net disturbance, while a ratio less than 1.0 indicates the opposite

b. Inspection and Enforcement

The LQD continues to conduct frequent and thorough inspections. LQD conducted 142 complete inspections and 251 partial inspections during the evaluation period. There are 30 of the 32 coal mines with active NPDES permits. The Wyoming Water Quality Division (WQD) conducted 94 inspections during the first three quarters of the evaluation period. As per an agreement between WQD and LQD, the LQD inspectors completed the WQD inspections for the fourth quarter, completing the required water quality inspections.

LQD performed more than the minimum required inspections for the Wyoming Program. All LQD performance standards were reviewed and documented during complete inspections and the reports contain a discussion of the current mine status.

The Casper Field Office conducted a total of twenty-one inspections, all of which were partial / focused inspections. CFO did not conduct any complete inspection during this evaluation period.

LQD maintains an inspectable units list and an inspection database sufficient to meet its program requirements. LQD has made this database available to the CFO.

LQD issued 7 Notices of Violation and no Imminent Harm or Failure to Abate Cessation Orders during this nine month evaluation period. No pattern of violation exists or show cause hearings / alternative enforcement action (bond forfeiture) were initiate during this evaluation period.

The CFO issued two (2) Ten-Day-Notices (TDNs) during this review period. One TDNs was resolved during the evaluation period and the other maybe be reopened.

VI. OSM Assistance

A. Training

OSM offers training courses through the National Technical Training Program (NTTP) to State regulatory authority employees at no expense to the State or the attendee (other than salary and benefits). OSM's technical training program provided a wide range of courses (some listed below). Nine Wyoming LQD employees received training from OSM's technical training program at a cost of $10,460 during EY2004.

The nine LQD employees participated in the following training courses:

Wetlands -	1 staff
Bonding: Cost Estimation -	2 staff
Evidence Preparation and Testimony -	1 staff
Historic / Archeological -	3 staff
NEPA Procedures -	1 staff
Blasting	1 staff

B. Office of Technology Transfer (OTT)

Wyoming Department of Environmental Quality Land Quality Division continues to participate in the technological advances by updating its hydrology database, developing a GIS for bond release, and exchanging electronic information for permitting activities. Wyoming staff made significant contributions to the new technologies workshops conducted by OTT this year.

Wyoming Staff made presentations at two OTT/WRTT New Technologies Implementation Workshops, and nine staff members (Georgia Cash-Hoenig, Rick Chancellor, Roberta Hoy, Mark Taylor, Christine Mielnicki, Mark Rogaczewski, John Erickson, Marcello Calle, and Carol Bilbrough) attended, and participated in discussions at the three workshops – for a total of fifteen attendees.

At the Denver New Technologies Implementation Workshop Mark Rogaczewski and Christine Mielnicki presented the status and accomplishments of the *WY Bond Release GIS*.

At the third New Technologies Implementation Workshop in Salt Lake City, June 2004, Mark Taylor presented an update on *Wyoming Pilot GIS for Bond Release*

Two staff members attended a day-long workshop on *Introducing GIS, Digital Imagery, and Volumetrics, and Advanced Modeling, Emphasizing Digital Imagery in GIS Applications*

To support the new technologies implementation, this year OTT purchased the following for Wyoming DEQ/LQD:

Geo XM mobile GPS receiver	$2,515
Terrasync Pro Software	$1,786
InFocus Projectors (Lander/Sheridan)	$3,838

Technical assistance to Wyoming in the area of bonding included providing:

Information on bond riders for permit renewals

Information on evaluating the quality of applicant's current assets as shown on its financial statements as it relates to self-bonding applications

Background on federal and state self-bonding regulations with respect to adding self-bond amounts to applicant's liabilities before calculating the financial tests

Information on five different changes to the Treasury Circular 570

OSM's Technical Librarian filled 2 reference requests, and provided 24 journal articles to Wyoming Staff. In addition Wyoming received 7 technical publications: The Seed and Soil Dynamics in Shrubland Ecosystem; Geologic Studies of Mercury by the USGS; Strontium Isotopic Characterization of Coal and Sandstone Aquifers, Powder River Basin; Evaluation and Comparison of Hypothesis Testing Techniques for Bond Release Applications; Native Plants Materials Directory; Proceedings of Market-Based Approaches to Mined Land Reclamation and Reforestation: A Technical Interactive Forum; Effect of Mechanical and Biological Enhancements on Erosion at High Elevation Disturbed Lands; and 10 CDs, that were distributed to WRTT.

C. Computer Support (TIPS)

TIPS personnel gave a brief presentation regarding TIPS' intent to provide scientific and engineering software directly to desktop workstations in TIPS customer locations. ArcInfo and AutoCAD software were delivered to the State with instructions for desktop and server installations during EY 2003. As a follow-up during EY 2004, TIPS held courses in ArcGIS Spatial Analyst, SEDCAD, and Introduction to ArcGIS. There were 16 LQD participants in the three courses at a cost of $6,467 to OSM.

KeyServer will be used to distribute software licensing to most TIPS software applications. TIPS advised each of state that the remaining TIPS software will be delivered by the end of the calendar year.

D. Cultural Resources

The CFO continues to coordinate the National Historic Preservation Act, Section 106 cultural resource compliance for the State of Wyoming. The CFO cultural resource coordinator works closely with the OSM Archaeologist in WRCC, Wyoming Department of Environmental Quality (DEQ), Bureau of Land Management (BLM), Wyoming State Historic Preservation Office (SHPO), the Advisory Council on Historic Preservation (ACHP), U. S. Forest Service (USFS) and the affected mining companies to process cultural resource clearances on new mining lands and previously permitted areas that have not been surveyed for cultural resources. This detailed involvement is necessary because the Wyoming DEQ does not have a qualified archaeologist on staff and therefore, the SHPO will not accept cultural resource work from them. The SHPO has taken the position that, by law, the Section 106 process is the responsibility of the lead Federal agency and that requires that OSM be responsible for this work on any mines under permit. Prior to OSM involvement with any parcel of land, the land managing agency (BLM or USFS) would be the lead Federal agency and would initiate the Section 106 process. The DEQ has indicated that they have no plans to place an archaeologist on staff since all Section 106 clearances are covered by Federal agencies. During this reporting period, action was taken on 6 projects in Wyoming, and one programmatic Agreement.

E. Revegetation Success Standards

During the 2004 Evaluation Year an OSM representative met several times with Wyoming staff as part of ongoing assistance in development of technical vegetation success standards. The OSM representative was also involved in discussions on the development of criteria for evaluating vegetative diversity and the selection and description of vegetation sampling techniques. Wyoming's goal is to revise and update its revegetation regulations to include appropriate success standards and statistically valid sampling techniques. As part of this assistance the OSM representative attended several meetings with Wyoming staff, including personnel from the three districts within the State, and representatives of the Wyoming Mining Association. OSM continues to provide technical assistance in this area at the request of the State.

VII. General Oversight Topic Reviews

A. Program Maintenance (Amendments)

Wyoming's Coal Regulatory Program contains unresolved program issues identified in OSM's letters issued pursuant to 30 CFR 732.17 and subsequent required program amendments and disapprovals identified under 30 CFR 950. Wyoming and OSM has identified all of the program deficiencies and established a schedule for submitting program amendments to OSM.

Wyoming has not been successful in meeting its schedule for rule changes. There have been bureaucratic and political barriers within the State's rulemaking process hindering progress. Many amendments are heard before the Land Quality Advisory Board and Environmental Quality Council several times without passing through to final rulemaking and submission to OSM for review and final decision.

CFO and LQD have thoroughly reviewed the outstanding program deficiencies. CFO has concluded, on the basis of its review and field monitoring, that there were no immediate potential environmental problems or threats attributed to the program deficiencies.

Of the original 126 deficient rules identified in 1994; 83 have been resolved within seven amendment packages. Thirty-six deficiencies remain to be addressed. Eighteen of these are Ownership & Control rules. WRCC has suggested that LQD delay working on these rules to the last due to OSM's current rule litigation..

There are six program amendments remaining. One amendment package has been submitted to OSM for review, two other amendment is in the State's rulemaking process and the remaining 3 packages have not been started.. The following is the current schedule for submitting amendments to OSM as proposed by LQD and approved by CFO:

Hydrology	Approved Nov. 2002
Permit Processing and Administration	Approved June 2002
Roads	Approved Nov. 2003
Coal Exploration (1R) (7 issues)	Submitted June 2004
Bond Release (1-U) (3 issues)	June 2006
Vegetation (1-S) (5 issues)	Sept. 2006
Non Coal Waste (1-B) (2 issues)	No Date Projected

Valid Existing Rights (1 issue)	Postponed at OSM request
Ownership and Control (18 issues)	Postponed at OSM request

The Wyoming Department of Environmental Quality, Land Quality Division (LQD) has addressed the majority of the outstanding program deficiencies.

As of October 2002, LQD lost its principle rulemaking specialist. LQD has hired a replacement, but in less than a year lost that individual. The duties for preparing rulemaking packages has been divided among the LQD staff in an effort to keep making progress.

The Vegetation amendment package (1-S) had been prepared for the Advisory Board meeting. At the board meeting, the Wyoming Mining Association submitted their version of a vegetation amendment package (1-S). Land Quality Advisory Board directed the LQD to review the WMA's amendment proposal and compare it with Amendment package 1-S and try to resolve differences with the WMA. So far this process has taken more then a year with very little progress despite the numerous meetings. The non-coal waste amendment (1-B) was rejected by the EQC and returned to the Advisory Board for a rewrite. No date has been projected for submitting to OSM. It needs to be re-addressed by the board and EQC again.

The Coal Exploration amendment package (1-R) finally passed through the EQC hearing process and has been submitted to OSM. The Administrative Procedures for Bond release amendment (1-P) was also passed by the board and will follow package 1-R to the EQC.

B. Financial Administration

CFO conducted financial oversight during the evaluation period. CFO visited DEQ offices in Cheyenne, Wyoming and reviewed financial information. Specifically, drawdowns, payroll approval, travel, property, Federal lands grant distributions, A-133 Audits, program income, timeliness and accuracy of grant applications and reports, were reviewed.

A drawdown analysis was conducted for the existing Administration and Enforcement (A&E) grant as well as the previous grant. Five draws from the previous and current grant were sampled. Wyoming drew the correct amounts for each draw and the draws followed appropriate expenditures. All draws were reimbursable. No problems were found.

Title V accounting records were reviewed to ensure that the State is following their policies and procedures for payroll. Both the supervisors and the employees are required to sign monthly timesheets. Signatures were adequate, and records are being kept not only of weekly hour worked but of sick and annual leave taken. No problems were found.

Policies and procedure allowances for air travel, per diem, lodging and mileage for personal vehicles were reviewed. Seven individual's travel for the past year who worked was samples. Over 30 vouchers were scrutinized. No problems were found. Supervisors are approving the vouchers, employees are also signing them as required by Wyoming policies and procedures. Per diem and lodging allowance were appropriate. No problems were found.

Wyoming is up to date with their travel property reports. Based on the current FAM property reporting requirements, the State is reporting property correctly though the number of properties required to be reporting is dwindling. No problems were found. Each year the Wyoming DEQ reports the respective number of acres that are Federal and non-Federal under permit in their grant application. This is the criterion for calculating what share of the grant are Federal lands and what share is not. Acreage reporting of Federal lands permitted and acres permitted under lands non-Federal as submitted by permitted operations were reviewed to ensure they agreed with what is in the grant. The reporting was accurate and no problems were found.

There are no outstanding findings for A-133 audits pertaining to Title V program, nor were there any that had to be resolved during the reporting period. A-133 audits are up to date and the planning of future audits is up to date.

There was no program income reported when this oversight was conducted.

DEQ is timely in their reporting required cost and progress reports and they are timely with their grant applications for Title V.

Appendix A:

Tabular Summary of Core Data to Characterize the Program

Appendix B:
State Comments on the Report

State Comments on the Report

From: "Rick Chancellor" <RCHANC@state.wy.us>
To: "Mark Humphrey" <mhumphre@osmre.gov>
Date: 10/1/2004 9:13:28 AM
Subject: Annual report

Mark,

I have completed a review of the draft Annual Evaluation Summary Report and found no major concerns. There are several editorial comments that are listed below:

1. Page 4, IV.B. Fugitive Dust. In the sixth line of the paragraph the word resolve should be resolved.

2. Page 4, IV.C. Innovations. The first sentence should also mention the North Antelope/Rochelle Mine.

3. Page 15, VII.A. Program Maintenance The forth paragraph states that four program amendments have been approved since 1995 (page 3 also states that four amendments have been submitted and approved since 1995). The first paragraph on page 16 states that seven program amendments have been submitted approved since 1995.

4. Page 17, VII.B. Financial Administration The second sentence of the second paragraph seems awkward. Perhaps it should read "were sampled."

5. Page 17, VII.B. Financial Administration The word "travel" in the first sentence seems out of place and perhaps should be deleted.

6. Page 17, VII.B. Financial Administration The word "not" in the last sentence should be "no."

Thank you for the opportunity to comment on the report.

Rick Chancellor

Appendix C:
CFO Response to State Comments

Appendix C: CFO Response to State Comments

LQD COMMENT:
1. Page 4, IV.B. Fugitive Dust. In the sixth line of the paragraph the word resolve should be resolved.

CFO RESPONSE:
This editorial change was made.

LQD COMMENT:
2. Page 4, IV.C. Innovations. The first sentence should also mention the North Antelope/Rochelle Mine.

CFO RESPONSE:
This editorial change was made.

LQD COMMENT:
3. Page 15, VII.A. Program Maintenance The forth paragraph states that four program amendments have been approved since 1995 (page 3 also states that four amendments have been submitted and approved since 1995). The first paragraph on page 16 states that seven program amendments have been submitted approved since 1995.

CFO RESPONSE:
This section was revised to make the text less confusing and more concise.

LQD COMMENT
4. Page 17, VII.B. Financial Administration The second sentence of the second paragraph seems awkward. Perhaps it should read "were sampled."

CFO RESPONSE:
This editorial change was made.

LQD COMMENT:
5. Page 17, VII.B. Financial Administration The word "travel" in the first sentence seems out of place and perhaps should be deleted.

CFO RESPONSE:
The first sentence was revised to make the text less confusing and more concise.

LQD COMMEN:
6. Page 17, VII.B. Financial Administration The word "not" in the last sentence should be "no."

CFO RESPONSE
This editorial change was made.