BLM

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Wright Area Coal Leasing 10th Circuit Court Remand

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Chapter 1

1.0 INTRODUCTION

Title: Wright Area Coal Leasing 10th Circuit Court Remand Environmental Assessment

Environmental Assessment (EA) Number: DOI-BLM-WY-P000-2018-0002-EA

Preparing Office: U.S. Department of the Interior (DOI)
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1.1 Background

BLM has prepared this EA to address the United States Tenth Circuit Court of Appeals September 15, 2017 decision remanding the Wright Area Environmental Impact Statement (EIS) and coal leasing decisions and the United States District Court's November 27, 2017 order which requires BLM to revise the environmental analysis in the EIS. The Tenth Circuit Court did not vacate the Wright Area leases, but rather, remanded the case to the District Court, which in turn ordered BLM to revise its analyses of the No Action Alternative in the 2010 Wright Area Final EIS (FEIS) where BLM previously concluded that "issuing the (Wright Area) leases would not result in higher national carbon dioxide emissions than would declining to issue them."

BLM issued four Records of Decision (RODs) based on the Wright Area EIS (see table below). In 2012, BLM issued and executed three of the Wright Area federal coal leases, as indicated below. The sale for the North Hilight Field has not yet been held.

Lease #	Lease Name	ROD signed	Mineable Federal coal reserves tonnage	Bonus Bid Revenues Paid to Federal Government	Approved WDEQ* permit for mine that purchased the new lease
WYW174596	South Hilight Field	3-1-2011	222,676,000	$300,001,011	Black Thunder 2014
WYW176095	South Porcupine	8-10-2011	401,830,508	$446,031,863	North Antelope/ Rochelle 2013
WYW173408	North Porcupine	10-17-2011	721,154,828	$793,270,310	North Antelope/ Rochelle 2013
WYW164812	North Hilight Field	2-1-2012	467,596,000	To be determined	To be determined

*Wyoming Department of Environmental Quality

In total, these four Wright Area coal lease tracts in the Wyoming portion of the Powder River Basin (PRB) include over 1.8 billion tons of mineable Federal coal reserves. The coal companies paid the Federal government over $1.5 billion in bonus bid revenues for three of the four lease tracts: the South Hilight Field, South Porcupine, and North Porcupine coal leases[1]. Under the Mineral Leasing Act, 49 percent of the bonus bid revenues was then disbursed back to the State of Wyoming. The federal government received record-setting bids for the Wright Area coal tracts. These three leases were all approved for mining in 2013 and 2014 by the WDEQ and mining is underway and ongoing at all three.

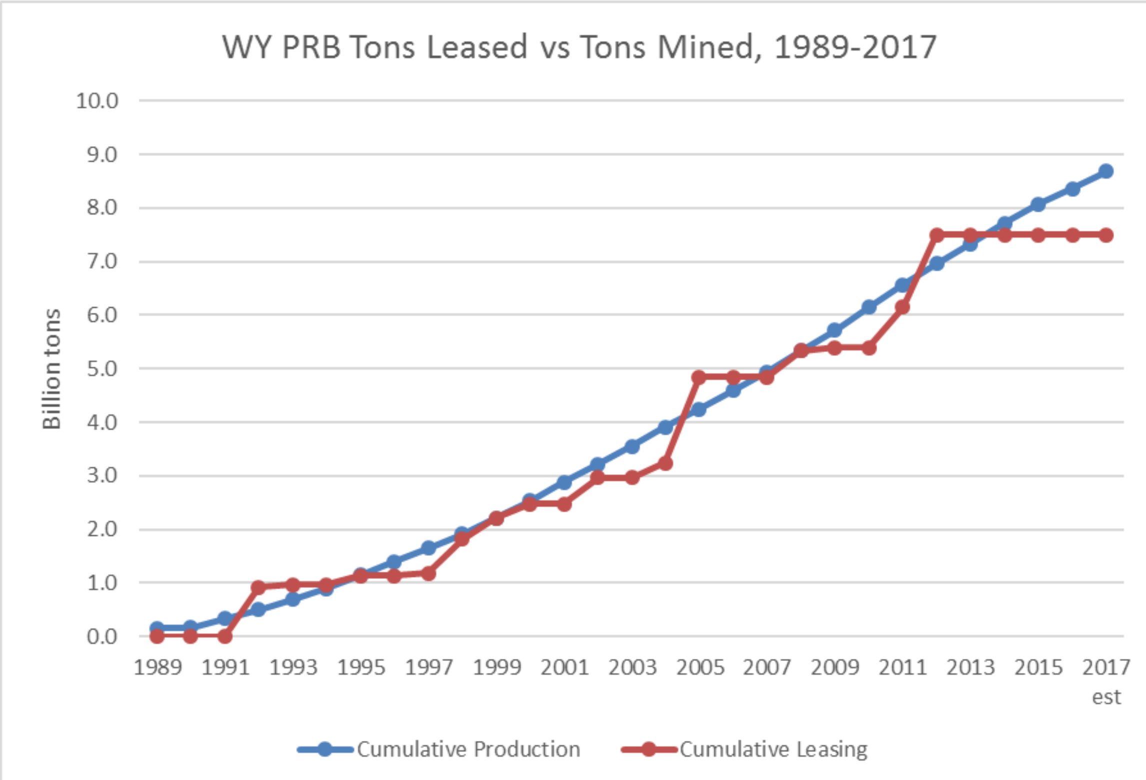
The Wright Area coal tracts were applied for as a direct result of anticipated national coal demand and market demand for affordable electricity. Given the amount of time it could take the BLM to process coal lease applications, coal companies in the PRB have tended to submit coal lease applications well before they anticipate potentially mining new coal tracts. The four tracts of interest are maintenance coal tracts meaning that the lease tracts would continue or extend the life of the existing mines. When a tract is leased as a maintenance tract, the permit to conduct mining operations for the adjacent mine is amended to include the new lease area prior to surface disturbance. This process can take several years to complete and so, in Wyoming, coal companies often apply for federal coal reserves approximately 10 years in advance of mining. This also allows time for designing logical mining progression.

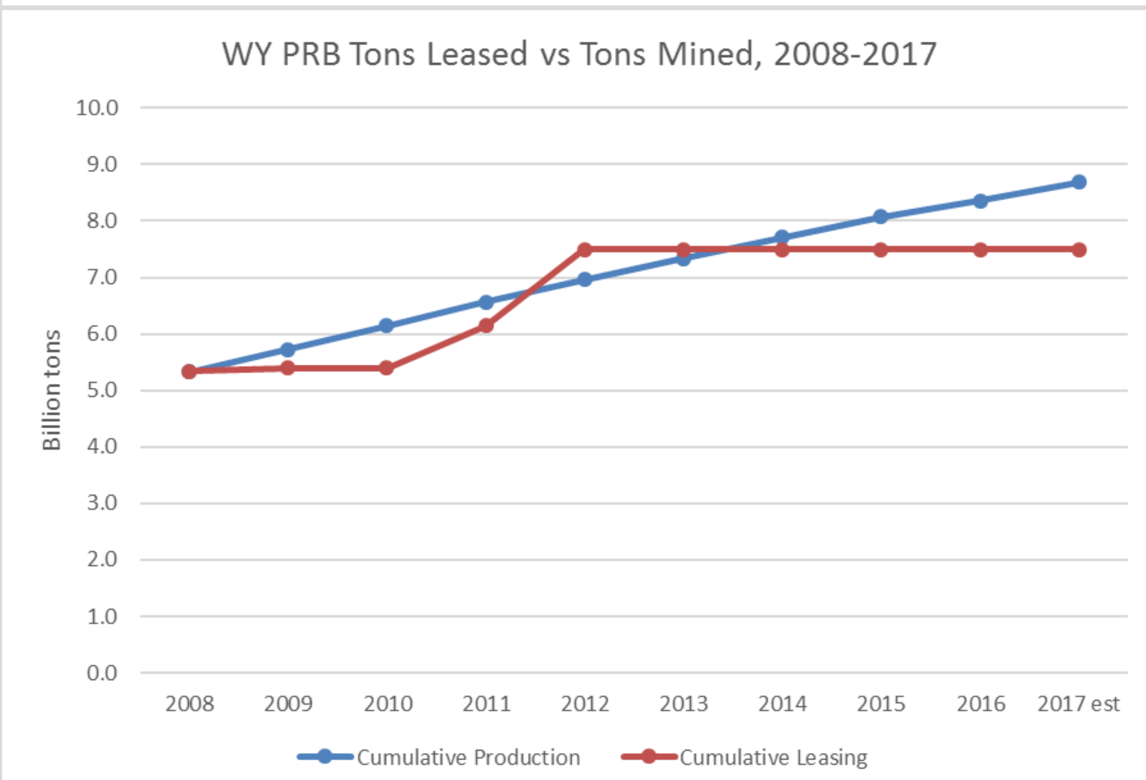
For example, the graph below shows cumulative Federal coal tons leased in the Wyoming portion of the Powder River Basin (WY PRB) versus cumulative coal tons produced in the WY PRB (both federal and non-federal) (Graph 1.1.1). As shown, federal coal leasing in the WY PRB has been consistent with coal production over time.

(Intentional blank space--Graph 1.1.1 on next page for spacing)

[1] The RODs for these three leases were signed in 2011, the sales of these three leases occurred in 2011 and 2012, and the three leases were issued in 2012.

Graph 1.1.1: Cumulative Federal Coal Tons Leased vs Cumulative Coal Tons Produced





Source: U.S. BLM High Plains District Office 2018

1.2 Purpose and Need

On September 15, 2017, the Tenth Circuit ruled that BLM's Wright Area EIS and RODs were "arbitrary and capricious" where BLM concluded that "issuing the (Wright Area) leases would not result in higher national carbon dioxide emissions than would declining to issue them." As stated by the court, "In the NEPA context, an agency's EIS is arbitrary and capricious if it fails to take a 'hard look' at the environmental effects of the alternatives before it (page 18)."

Consistent with the District Court's November 27, 2017 order, BLM has prepared this EA to revise the Wright Area EIS' analysis of the No Action Alternative and clarify what potential changes in national carbon dioxide emissions may have taken place if BLM had declined to issue the Wright Area coal leases.

The Tenth Circuit ruled that:

- The Wright Area decisions lacked record support for BLM's conclusion that "it is not likely that selection of the No Action Alternative would result in a decrease of U.S. CO_2 emissions attributable to coal mining and coal-burning power plants in the longer term, because there are multiple other sources of coal that . . . could supply the demand for coal . . ." (page 8-9).

- "BLM concluded that, because overall demand for coal was predicted to increase, the effect on the supply of coal of the no action alternative would have no consequential impact on that demand. This long logical leap presumes that either the reduced supply will have no impact on price, or that any increase in price will not make other forms of energy more attractive and decrease coal's share of the energy mix, even slightly" (page 9).

- "The BLM did not point to any information indicating that the national coal deficit 230 million tons per year incurred under the no action alternative could be easily filled from elsewhere, or at a comparable price. It did not refer to the nation's stores of coal or the rates at which those stores may be extracted. Nor did the BLM analyze the specific difference in price between PRB coal and other sources . . ." (page 20).

- "BLM argues, overall increased demand for electricity will override the effect of increased coal prices. But there is no evidence in the record that BLM considered the potential impact of increased price on demand but rather BLM merely concluded it would have no impact. The record contains only BLM's conclusions that the effect on demand would be 'inconsequential,' with no reference to how, or if, it decided which demand-driving factors would prevail or why" (page 22-23).

- " . . . BLM's carbon emissions analysis seems to be liberal (i.e., underestimates the effect on climate change). The RODs assume that coal will continue to be a much used source of fuel for electricity and that coal use will increase with population size . . . Moreover, the climate modeling technology exists: the NEMS program is available for the BLM to use" (page 26).

This EA provides additional information and analysis for the Wright Area administrative record, and provides another opportunity for public comment. After the public comments have been considered, BLM will prepare the final EA.

1.3 Relationship to Statutes, Regulations, Plans, and Other Environmental Analyses

The development of federal coal reserves is integral to the BLM Federal Coal Leasing Program under the authority of the Mineral Leasing Act of 1920 (MLA), as well as the Federal Land Policy Management Act of 1976 (FLPMA) and the Federal Coal Leasing Act Amendments of 1976 (FCLAA). BLM is the lead agency responsible for leasing federal coal lands under the MLA as amended by FCLAA.

After a coal lease is issued, Surface Mining Control and Reclamation Act of 1977 (SMCRA) gives the United States Department of the Interior Office of Surface Mining Reclamation and Enforcement (OSMRE) the primary responsibility to administer programs that regulate surface coal mining operations and the surface effects of underground coal mining operations. Pursuant to Section 503 of SMCRA, the Wyoming Department of Environmental Quality (WDEQ) developed, and in November 1980 the Secretary of the Interior approved, a permanent program authorizing WDEQ to regulate surface coal mining operations and surface effects of underground mining on non-federal lands within the State of Wyoming. In January 1987, pursuant to Section 523(c) of SMCRA, WDEQ entered into a cooperative agreement with the Secretary of the Interior authorizing WDEQ to regulate surface coal mining operations and surface effects of underground mining on federal lands within the state. Pursuant to this agreement, federal coal lease holders in Wyoming must submit permit application packages to OSMRE and WDEQ for proposed mining and reclamation operations on federal lands in the state.

Land Use Plan Conformance:

FCLAA requires that lands considered for leasing be included in a comprehensive land use plan and that leasing decisions be compatible with that plan. The BLM Approved Resource Management Plan (RMP) for Public Lands Administered by the Bureau of Land Management Buffalo Field Office (2001) governed and addressed the leasing of federal coal in Campbell County. The Wright Area coal tracts were all located within the Coal Development Potential Area, as identified and described in the Buffalo RMP.

Other Environmental Analyses and Prior Legal Challenges:

The Powder River Basin (PRB) Coal Review was a regional technical study completed by the BLM to help evaluate the cumulative impacts of coal and other mineral development in the PRB. Initiated in 2003, Phase I of the PRB Coal Review included the identification of current conditions (Task 1 reports); identification of Reasonable Foreseeable Development (RFD) and future coal production scenarios for 2010, 2015, and 2020 (Task 2 reports); and predicted future cumulative impacts (Task 3 reports) in the PRB. Phase II of the PRB Coal Review updated the Phase I analyses, developed future coal production scenarios, and projected cumulative impacts for 2020 and 2030.

The PRB Coal Review provides data, models, and projections to facilitate cumulative analyses for BLM's future land use planning efforts and for future project-specific impact assessments for project development in compliance with NEPA. It should be noted that the PRB Coal Review itself is not a NEPA document. The Powder River Basin Coal Review and related documents are accessible at the following link:
https://eplanning.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=dispatchToPatternPage&currentPageId=91868

The Wright Area EIS analyzed the potential leasing and mining of federal coal reserves in response to lease-by-applications (LBAs) filed by the operating mining companies in the Wyoming portion of the Powder River Basin. The Wright Area EIS utilized the PRB Coal Review study for the cumulative effects analysis in the EIS. The EIS was used by BLM as the basis for the decisions to hold competitive, sealed-bid sales and eventual issuance of the Wright Area coal leases that had successful lease sales. The Wright Area FEIS is accessible at the following link:
https://eplanning.blm.gov/epl-front-office/eplanning/legacyProjectSite.do?methodName=renderLegacyProjectSite&projectId=67033

In challenges to the leasing decisions, the Interior Board of Land Appeals and Wyoming District Court found that BLM's analysis of the environmental impacts of the leasing actions complied with NEPA. The Tenth Circuit's 2017 remand was for only a single issue, the potential impacts to greenhouse gas emissions given current and projected coal supply and demand and fuel substitution by electricity generating plants associated with the Wright Area project's No Action Alternative. This EA clarifies and addresses that issue.

1.4 Scoping and Public Involvement

On approximately July 30, 2018, BLM will announce a 30-day public comment period for this EA. On March 5, 2018, BLM also issued a press release announcing that BLM was preparing a Wright Area Remand EA, which was posted at the following link:
https://eplanning.blm.gov/epl-front-office/eplanning/%20projectSummary.do?methodName=renderDefaultProjectSummary&projectId=97202

From May through July, 2018, BLM received over 5,000 emails from the public concerning this EA. Many of the messages appeared to be generated from a form letter available at the following website/email address: action@wildearthguardians.org. During that time, BLM also received signed letters in the mail regarding this EA from Jim Steitz, Thunder Basin Coal Company, and BTU Western Resources, Inc.

Many opportunities for public involvement have been provided for throughout the entire BLM Wright Area EIS project. To start, the Powder River Basin Regional Coal Team (RCT) reviewed all the Wright Area coal lease applications at public meetings held on April 19, 2006 and January

18, 2007 in Casper, Wyoming. Notices that announced the RCT public meetings were published in the Federal Register on February 9, 2006 and December 12, 2006.

BLM published a Notice of Intent (NOI) to prepare an EIS and Notice of Public Meeting in the Federal Register on July 3, 2007, in the Gillette News-Record newspaper on July 6, 2007, and in the Douglas Budget newspaper on July 11, 2007. The publications served as public notice that the Wright Area coal lease applications had been received, announced the time and location of the public scoping meeting, and requested public comment on the coal lease applications. On July 11, 2007, letters requesting public comment and announcement of the time and location of the public scoping meeting were also mailed to all parties on the distribution list. The public scoping meeting was held July 24, 2007 in Gillette, Wyoming.

The U.S. Environmental Protection Agency (EPA) published a notice announcing the availability of the Draft EIS in the Federal Register on June 26, 2009. Parties on the distribution list were sent copies of the Draft EIS, and copies were made available for review at the BLM offices in Casper and Cheyenne, Wyoming. The document was also available for review on the BLM Wyoming internet site. A 60-day comment period on the Draft EIS commenced with publication of the EPA's Notice of Availability (NOA) and ended on August 25, 2009.

BLM published a NOA/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 public hearing, which was held during the 60-day comment period on July 29, 2009 at 7:00 p.m. at the Clarion Inn in Gillette, Wyoming. The purposed of the public hearing was to solicit public comments on the Draft EIS and on the fair market value, the maximum economic recovery, and the proposed competitive sale of federal coal from the LBA tracts. BLM also published a notice of public hearing in both the Douglas Budget and Gillette News-Record newspapers on July 8, 2009. 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.

A notice announcing the availability of the *Wright Area Coal Lease Applications Final EIS* (FEIS) 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. The public review period was open for 30 days after EPA's NOA published in the Federal Register. All comments that were received in a timely manner were considered in the preparation of the Wright Area Records of Decision (RODs).

The Wright Area coal tracts were additionally reviewed during the OSMRE/WDEQ mine permit process. The South Hilight Field, North Porcupine, and South Porcupine have all been permitted by the WDEQ for surface disturbance and coal mining activity.

Chapter 2

Proposed Action

2.1 Proposed Action

Under the Proposed Action, BLM is providing additional clarification and environmental analysis of the Wright Area EIS' No Action Alternative to disclose and analyze potential impacts to greenhouse gas emissions if the leases were not issued. Because this analysis was required by the Tenth Circuit's remand, the BLM is not considering any other alternatives to comply with the Court's order.

Chapter 3

Affected Environment

As previously mentioned, the Wright Area EIS analyzed the potential leasing and mining of federal coal reserves in response to lease-by-applications (LBAs) filed by the operating mining companies in the Wyoming portion of the PRB. The Wright Area EIS originally studied six LBA tracts, all located within the Wyoming portion of the PRB: North Hilight Field, South Hilight Field, West Hilight Field, North Porcupine, South Porcupine, and West Jacobs Ranch. After the FEIS was completed, two of the LBA tracts (West Jacobs Ranch and West Hilight Field) were withdrawn per company request. BLM issued four Records of Decision (RODs) for the other LBAs and these are the RODs that are challenged in this case: South Hilight Field, North Porcupine, South Porcupine, and North Hilight Field.

Surface ownership in the Wright EIS general analysis area consisted mainly of private lands intermingled with federal lands. In total, the Wright Area coal tracts, as delineated by BLM, contained about 65.1 percent private ownership, 34.4 percent federal ownership, and 0.5 percent state ownership. Livestock grazing is the primary land use while oil and gas production, wildlife habitat, communication and power lines, transportation, and recreation are all secondary land uses on both public and private lands. Areas of surface disturbance within and near the Wright Area coal tracts include roads, oil and gas wells and associated production facilities, surface mine related facilities and activities, and activities associated with ranching operations. The oil and gas estate within the general Wright EIS analysis area is federally and privately owned. Most of the federally owned oil and gas estate is already leased.

When the NEPA analyses and Records of Decision (RODs) for the Wright Area LBA tracts were prepared, the Black Thunder Mine (applicant of the North and South Hilight Field LBA tracts, W-164812 and W-174596 respectively) had approximately 10 years of remaining coal reserves without the addition of these two tracts. The addition of the South Hilight was projected to add approximately 1.6 years of life to the mine, and the North Hilight was projected to add approximately 3.1 years, based on the 2008 production rate of 135 million tons per year.

The North Antelope/Rochelle Mine (applicant of the North and South Porcupine LBA tracts, W-173408 and W-176095 respectively) had approximately 10 years of remaining reserves without the addition of the two tracts. The addition of the North Porcupine was projected to add approximately 7.8 years of life to the mine, and the South Porcupine was projected to add approximately 3.6 years, based on a production rate of approximately 100 million tons per year.

Coal from the Wyoming PRB is almost exclusively used for electric power generation units across the U.S. As such, as discussed in the cumulative effects section of the Wright Area EIS, BLM's analysis relied upon multiple interacting factors influencing the electric generation market including: the fuel mix based on market demand, available capacity within the coal market, pricing within the fuel market and the time frame for the market to adjust.

Chapter 4

Environmental Impacts and Consequences: Clarifications, Additions, and Revisions

4.0 Introduction

This chapter further explains and describes the clarifications, additions, and revisions that BLM has made to address projections of different fuel source shares of the electric utility markets and fuel substitution elasticities[2], with a focus on coal supply and demand and the interplay of these factors with potential changes in greenhouse gas emissions if the Wright Area coal leases had not been issued. BLM's revised analysis first elaborates on information available when the leasing decisions were made in 2010 to more effectively clarify and document the information the BLM considered in the leasing decision. The revised analysis then discusses the status of the three issued leases and one pending lease within the context of forecasted electric utility generation, different fuel source shares and potential greenhouse gas emissions. The focus on electricity generation is because almost all of the coal mined from the Wyoming PRB is used in coal-fired power plants to generate electricity.

There are numerous factors that influence the various fuel sources, their market shares in electricity generation and the substitution of fuels by power generating facilities. These factors include the availability of power generation facilities, operational costs including fuel prices, investment decisions, changing regulations, transportation availability and costs, and environmental constraints (Bopp and Costello 1990; Dahl and Ko 1998; Ko and Dahl 2001; Tuthill 2008; EIA 2008a; FERC 2009; EIA 2010a; Kaplan 2010). In other words, electric utility markets are quite complex with a myriad of factors, some market related, some not, playing a role in fuel use decisions. Given this complexity, in order to assess the national electric generation portfolio and the potential mix of future electric generation technologies for the NEPA analysis, the BLM reviewed numerous documents and data (including the aforementioned

[2] Fuel substitution elasticity refers to how the use of various fuels varies as their relative prices change (EIA 2012).

cited documents) with an emphasis on the *Annual Energy Outlook 2010* (*AEO2010*) (EIA 2010a). The *AEO2010* and its associated documents discussed the current electric generation mix as well as provided projections of the electric generation mix through 2035. The *AEO* is produced by the Energy Information Administration (EIA), which is the statistical and analytical agency within the U.S. Department of Energy and is "the nation's premier source of energy information" (EIA 2018a).

4.1 Revised Analysis and Clarifications

Historical Coal Production and Electric Power Generation Trends

To provide context for the *AEO2010* projections, a brief review of the historical trends from the *Annual Energy Review 2008* (EIA 2009a) and the *Annual Coal Report 2008* (EIA 2010d) are provided here[3]. United States (U.S.) coal production in 2008 reached a record of 1,171.8 million short tons whereas coal consumption in the electric power sector was only 1,040.6 million short tons due to the economic downturn and weather which led to lower electricity demand (EIA 2010d). However, traditionally, U.S. coal consumption has tended to be lower than U.S. coal production (EIA 2009a). Historically most coal production occurred in the Appalachian and Interior regions, until 1999 when the Western region coal production surpassed the other region's production[4] (EIA 2009a; 2010d). In 2008, 54.1 percent of U.S coal produced occurred in the Western region, 33.3 percent in the Appalachian region, and 12.5 percent in the Interior region (EIA 2010d). Coal production from the Wyoming Powder River Basin (PRB) accounted for 38.5 percent of total U.S. coal production in 2008[5] (EIA 2010a). Coal production (sales volume) from onshore federally-administered lands, including American Indian lands, accounted for 43.3 percent of total U.S. coal production in fiscal year 2008[6] (EIA 2009a).

While prior to the 1960s coal was consumed in the industrial sector and transportation sector (coal steam-driven trains and ships), most coal by the 1960s was used for electricity generation with 93% of all coal consumed in 2008 being in the electric power sector (EIA 2009a). Coal steadily increased its market share of the net electric power generation since the 1950s as Graph 4.1.1 shows (EIA 2009a). Natural gas was the second largest fuel source used for electricity generation and had been steadily climbing since the 1990s (see Graph 4.1.1). Nuclear energy (the third largest source) experienced growth from 1970 through 1990 but began leveling off in the early 2000s (see Graph 4.1.1).

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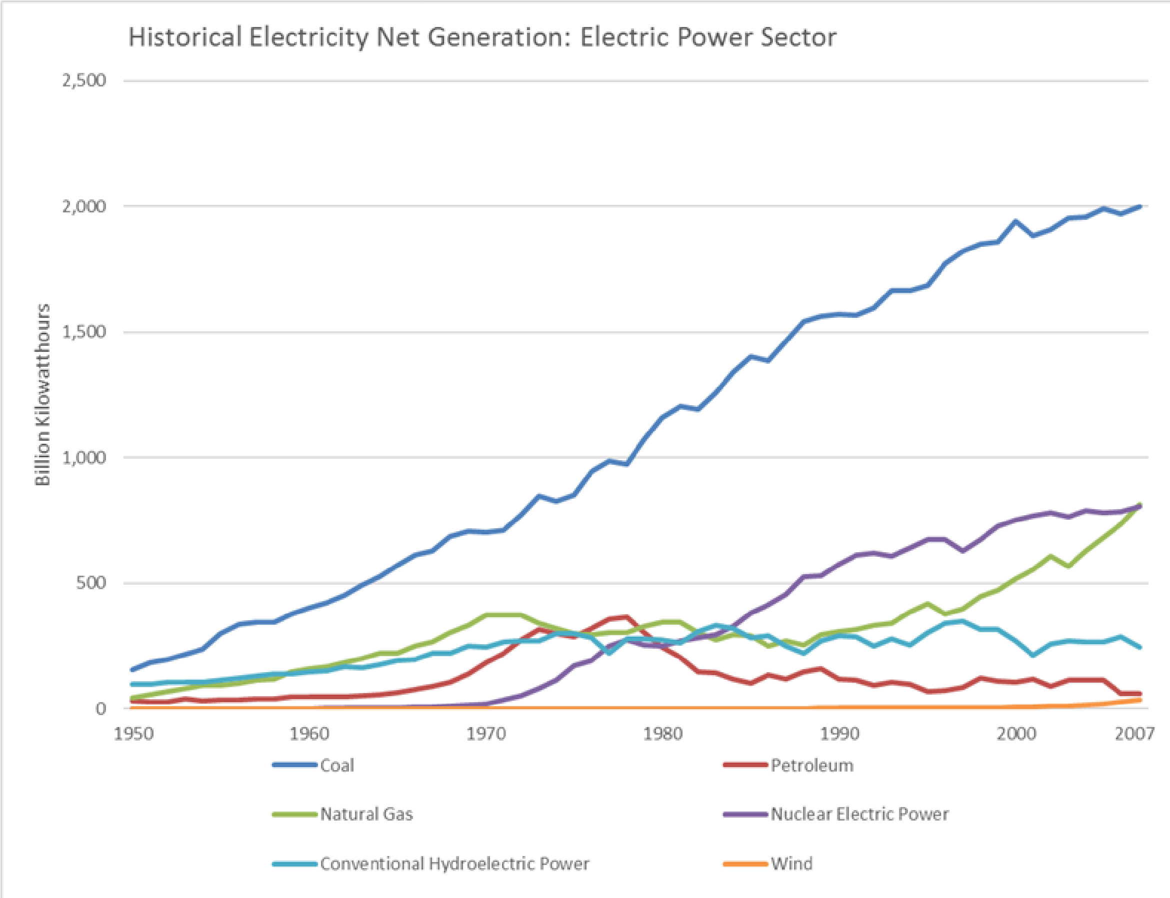
[3] Additional detailed discussions are included throughout the chapter as needed.

[4] EIA distinguishes the coal regions by these states:
Appalachian region: Alabama, Kentucky (eastern), Maryland, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia
Interior region: Arkansas, Illinois, Indiana, Kansas, Kentucky (western), Louisiana, Mississippi, Missouri, Oklahoma, Texas
Western region: Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Wyoming

[5] Additionally, Wyoming PRB coal accounted for 55.5% of U.S. surface-mined coal production in 2008 (EIA 2010a).

[6] EIA 2009a only provides a total production level for both Federal and American Indian lands. However, EIA 2015 indicates that 41.6% of the coal produced (based on sales volume) was from federal lands and 2.2% on Indian lands in FY2008.

Graph 4.1.1. Historical Electricity Net Generation: Electric Power Sector



Source: EIA 2009a

AEO 2010 Projections

The projections in the *AEO2010* (EIA 2010a) are produced using the National Energy Modeling System (NEMS) which is an economic and energy model of the U.S. energy markets which projects (approximately 25 years into the future), the production, consumption, conversion, import, export, and pricing of energy (EIA 2010a,b). In addition to NEMS producing *AEO* projections, it is "also used in analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies" (EIA 2010a, p. 195). Due to differences in energy supply, demand, and conversion factors across the United States, NEMS takes a regional approach which represents the regional differences in energy markets and transportation flows (EIA 2010b). NEMS uses various modules which "represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system" (EIA 2010a, p. 195) including macroeconomic and international modules[7]. Additionally, NEMS incorporates the impacts and costs of current

[7] NEMS modules include: Integrating, Macroeconomic Activity, International, Residential and Commercial Demand, Industrial Demand, Transportation Demand, Electricity Market, Renewable Fuels, Oil and Gas Supply, Natural Gas Transmission and Distribution, Petroleum Market, and Coal Market (EIA 2010a).

legislation and regulation that affect the various sectors (EIA 2010a). Although the *AEO2010* tends to emphasize the projections generated by NEMS for the *AEO2010* Reference case (scenario), projections are generated for 38 sensitivity cases "which explore important areas of market, technological, and policy uncertainty in the U.S. energy economy" (EIA 2010a, p. 2). More information on the NEMS model, its various components, and constraints on BLM using the NEMS model for the Wright EIS is included in Appendix A.

The discussion of the *AEO2010* projections for total electricity generation by fuel source type for the Reference case are based upon baseline economic growth of 2.4% per year from 2008 through 2035 (EIA 2010a). The Reference case sets the basis for examining the direction of future energy market trends under the assumption that current laws and regulations remain unchanged through the projections (EIA 2010a). In addition to the Reference case, projections across a select number of cases that examine differing economic and energy market conditions are also discussed. These other cases and the reason for their inclusion are discussed below.

When the NEPA analysis and Records of Decision (RODs) for the Wright Area LBA tracts were prepared, *AEO2010* indicated that in 2008 total electricity generation derived from coal in the United States was approximately 48.5%, while 21.4% was from natural gas and 19.6 % from nuclear power (Table 4.1.1). Table 4.1.1 also indicates that in 2008 a little over nine percent of electricity was generated using renewable sources with the remaining electricity generated by petroleum or other sources.

Table 4.1.1: *AEO2010* Total Electricity Generation Market Shares in 2008 and Projections for 2025 and 2035 for Three Cases

		2025			2035		
	2008	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Coal	48.5%	45.5%	45.0%	43.9%	44.7%	43.8%	43.6%
Petroleum & Other Fuels	1.5%	1.5%	1.5%	1.5%	1.5%	1.4%	1.3%
Natural Gas	21.4%	17.7%	18.3%	19.5%	20.0%	20.8%	20.5%
Nuclear Power	19.6%	19.8%	18.6%	17.7%	18.5%	17.1%	16.5%
Renewable Sources	9.1%	15.3%	16.7%	17.4%	15.3%	17.0%	18.1%
Total Electricity Generation (Billion Kilowatts)	4115.9	4466.1	4769.5	5045.6	4766.3	5259.2	5749.4

Source: EIA 2010a

To project electricity demand and generation needs into the future, the NEMS electricity market module considers numerous operational, economic, and environmental factors such as existing capacity, fuel prices, operating costs, demand loads, emissions at generating units, new technologies, and potential options for new generation facilities while also interacting with the other NEMS modules (EIA 2010c). Projections from *AEO2010* indicate that in the Reference case, electricity demand is anticipated to increase by 27.8 percent from 2008 to 2035, approximately 1.0 percent growth per year (EIA 2010a). Since energy demand is anticipated to vary due to external economic conditions (EIA 2008a; EIA 2010a), *AEO2010* included projections for a Low Economic Growth case and High Economic Growth case where total electricity generation (demand) was approximately nine percent lower (Low Economic Growth case) or higher (High Economic Growth case) than the Reference case (EIA 2010a). As indicated in Table 4.1.1 it is projected that in all three cases the market share of coal in 2025 and 2035 decreases while still maintaining the largest market share in total electricity generation in both years. Across all three cases in 2025 and 2035 there is a considerable increase in the market shares of renewable sources for total electricity generation (see Table 4.1.1). This is in part due to Federal tax credits, state requirements for renewable electricity generation, and concerns about greenhouse gas emissions (EIA 2010a). In other words, *AEO2010* projections indicated that some variation in fuel source shares of electricity generation were anticipated to occur between 2008 and 2035, with an increasing use of natural gas and to a lesser extent renewable sources, and coal still comprising the largest market share (EIA 2010a).

Additionally, to examine how changes in coal production and transportation costs could influence fuel source decisions and electricity demand, *AEO2010* included a Low Coal Cost case and a High Coal Cost case. In the Low Coal Cost case coal mining productivity growth rates were assumed to increase at a rate of 3.2 percent per year through 2035 whereas in the Reference case productivity was assumed to decline by 0.3 percent per year and in the High Coal Cost case decline at an average rate of 3.0 percent per year (EIA 2010b). Coal mining wages, mine equipment and supply costs, and transportation rates were assumed to be lower in 2035 when compared to 2008 for the Low Coal Cost case and higher for the High Coal Cost case (see EIA 2010b p. 155 for more details).

As can be seen in Table 4.1.2, under both the Low Coal Cost and High Coal Cost cases for 2025 and 2035, coal was also projected to have the largest market share in total electricity generation (as it was projected to in the three previous cases discussed above). Given the higher costs in the future associated with the High Coal Cost case, it was projected that in 2035 coal will have 41.0 percent share of the electricity generation market with natural gas and renewable sources increasing to 22.1 percent and 18.1 percent respectively (Table 4.1.2). The Low Coal Cost case projected an increase in coal's market share from 2025 to 2035, going from 45.7 percent to 46.5 percent. However, when compared to the 48.5 percent market share for coal in 2008 (see Table 4.1.1) there is still an overall projected downward trend in coal's share of the electricity generation market (Table 4.1.2).

Table 4.1.2: *AEO2010* Total Electricity Generation Market Shares-Projections for 2025 and 2035 for the Low Coal Cost and High Coal Cost cases

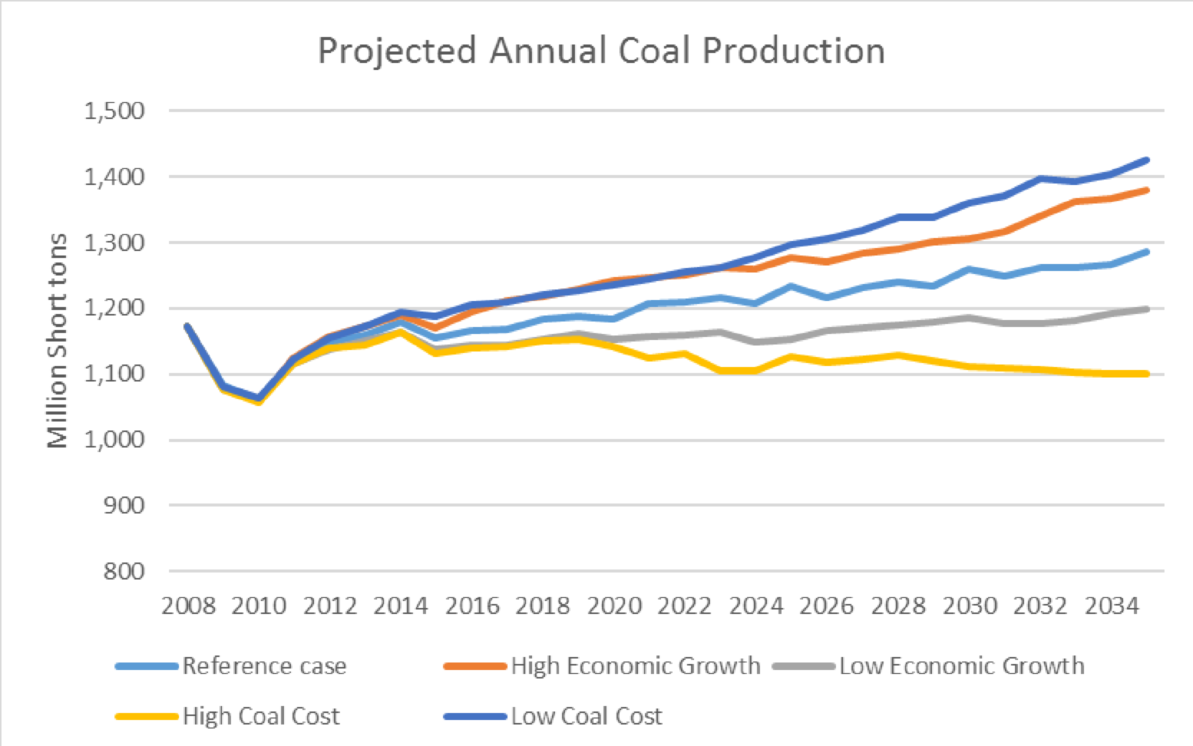
	2025		2035	
	Low Coal Cost	High Coal Cost	Low Coal Cost	High Coal Cost
Coal	45.7%	43.7%	46.5%	41.0%
Petroleum & Other Fuels	1.5%	1.5%	1.3%	1.4%
Natural Gas	17.9%	18.8%	19.5%	22.1%
Nuclear Power	18.5%	18.7%	16.7%	17.4%
Renewable Sources	16.3%	17.3%	16.0%	18.1%
Total Electricity Generation (Billion Kilowatts)	4789.0	4737.4	5302.1	5198.0

Source: EIA 2010a

As indicated by Table 4.1.1 and Table 4.1.2 electricity generation (demand) is anticipated to increase from 2008 to 2035 under these five cases as projected in *AEO2010* (EIA 2010a). In the Low Coal Cost case the amount of electricity generation in 2035 is similar to the amount projected for the Reference case (5302.1 versus 5259.2 billion kilowatts respectively) even with the considerably lower coal production and transportation costs. Projected electricity demand in 2035 is highest with the High Economic Growth case and lowest in the Low Economic Growth case indicating that electricity demand is driven more by overall economic conditions than coal production and transportation costs (EIA 2010a). The Coal Cost cases do indicate that coal costs can have a slight effect on fuel source decisions with a projected increase in natural gas and renewable sources, especially under the High Coal Cost case; however, coal was still projected to comprise the largest market share of total electricity generation in 2025 and 2035 under all five cases. Among the five cases, in 2035 the Low Coal Cost case projected the largest market share of electricity generation being met by coal (46.5 % versus 43.8% in the Reference case), while the market shares of natural gas and renewable sources in the Low Coal Cost case were projected to be similar to those in the Reference Case (19.5% and 20.8% for natural gas; 16.0% and 17.0% for renewable sources).

Although coal is projected to have lower market shares in future electricity generation, it will continue to be a key fuel source through 2035 (EIA 2010a). As previously discussed, in 2008, total U.S. coal production had reached a record level of 1,171.8 million short tons with 54.1 percent produced in the Western region (EIA 2010d). In order to supply projected electricity generation demands and coal-to-liquid plants, *AEO2010* projected that coal production will continue to increase after 2010 albeit at a much slower rate for four of the five cases discussed (see Graph 4.1.2). In the High Coal Cost case, however, total coal production is projected to be lower through 2035 than 2008 production levels (see Graph 4.1.2). Even with potential reductions in coal market shares in meeting electricity generation demands, coal production is projected to continue with over 1,000 million short tons being produced each year for all five cases discussed (EIA 2010a).

Graph 4.1.2 Projected Annual Coal Production



Source: EIA 2010a

To address coal demands of new and existing electric power plants across the U.S., *AEO2010* projected that in 2025 and 2035 most coal production will occur in the Western region for all five cases discussed (EIA 2010a). In particular, the Wyoming PRB was anticipated to produce a range of 40 to 50 percent of total U.S. coal production in all but the High Coal Cost case in 2025 and 2035 (see Table 4.1.3). Forecasted reductions in coal production in the Western region are slightly offset by small increases in coal production in the Interior region in the High Coal Cost case (EIA 2010a).

Table 4.1.3: *AEO2010* Projections of Wyoming Powder River Basin Coal Production as Percent of Total U.S. Coal Production

	Reference case	High Economic Growth	Low Economic Growth	High Coal Cost	Low Coal Cost
2025	43.7%	44.2%	43.1%	36.3%	47.0%
2035	42.9%	41.4%	42.9%	28.8%	49.6%

Source: EIA 2010a

Based on *AEO2010* projections as discussed above and given that in 2008 the applicants, associated with the four lease tracts of interest for this EA, had an average of 10 years of coal already leased to mine at permitted levels without these lease tracts, the BLM conceivably concluded that there would be continued coal production in the U.S. and use of coal for electricity generation, although perhaps at lower levels than was seen in 2008. The expectation that coal would continue to contribute to meeting electricity generation demands was also supported by data on recoverable reserves, mine capacity utilization, and the levels of existing coal stocks as discussed below.

Recoverable Reserves, Mine Capacity Utilization, and Existing Coal Stocks, 2008

When it prepared the NEPA analysis and RODs for these leasing decisions, the BLM also reviewed existing data on recoverable reserves, mine capacity utilization and existing coal stocks to examine if possible coal substitutes could be available if the four tracts were not leased. Based upon information in the *Annual Coal Report 2008* (EIA 2010d), in 2008 total U.S. recoverable coal reserves were estimated to be 261,573 million short tons with the highest estimated recoverable coal reserves in Montana at 74,810 million short tons, 37,935 in Illinois and 39,190 million short tons in Wyoming (EIA 2010d). Recoverable coal reserves represents the coal resources that could be technologically mined after considering accessibility[8] and recovery rates (EIA 2010d). This indicates that if demand warranted additional coal, coal resources exist that could potentially be mined, especially in Montana.

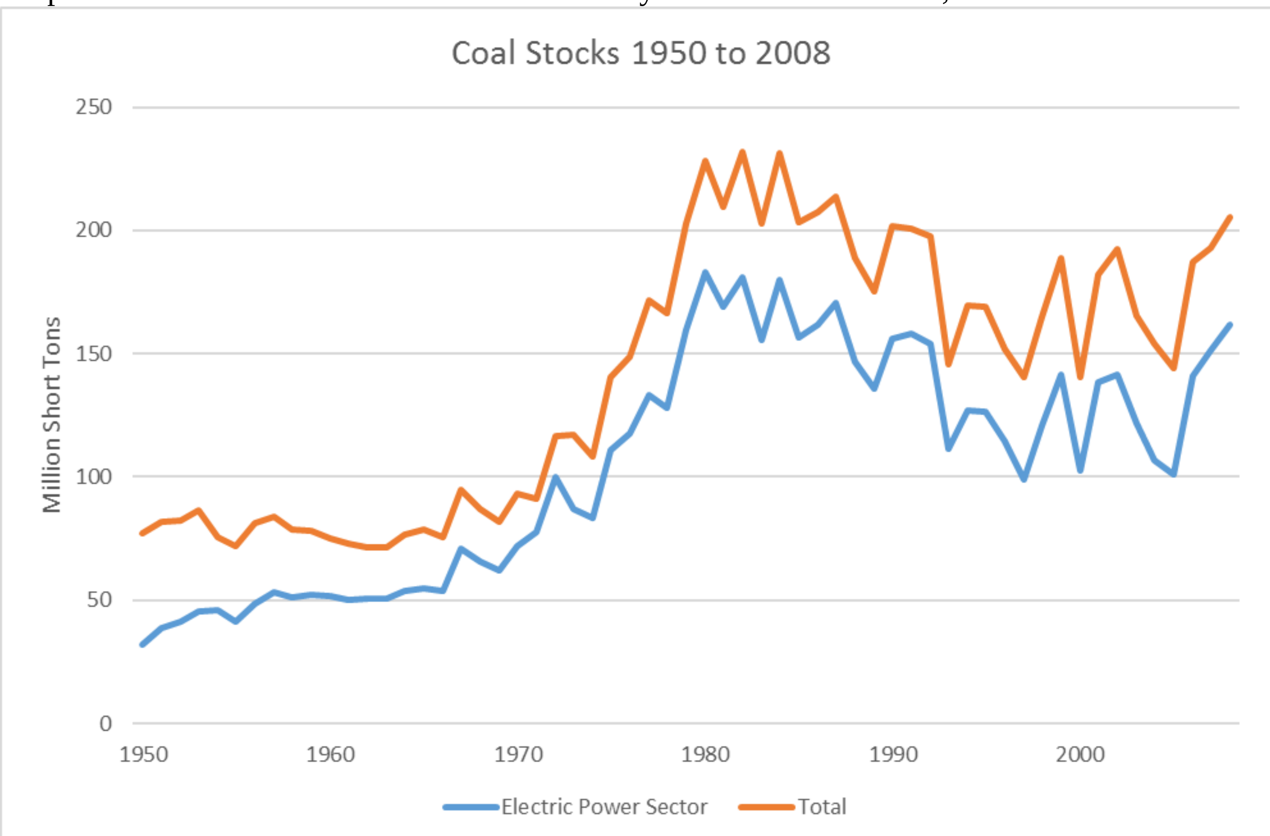
In addition to recoverable coal reserves, another factor taken into consideration was the utilization of the productive capacity at existing coal mines. Productive capacity is the "maximum amount of coal that can be produced annually as reported by mining companies…" (EIA 2010d, p. 32) and capacity utilization is "the ratio of annual production to annual productive capacity" (EIA 2010d, p. 33). In 2008, coal mines in Wyoming had a capacity utilization of 93.3 percent meaning they were producing close to their full capacity, while overall U.S. capacity utilization was 85.2 percent (EIA 2010d). The total productive capacity was 1,372.9 million short tons in 2008 for U.S. coal mines while total U.S. coal consumption was 1,120.5 million short tons which indicates total U.S. coal consumption in 2008 was lower than the maximum mine capacity available to produce coal (EIA 2010d). This means that if electricity generation demand warranted increased coal production, coal mines could increase production to permitted levels. It should be noted that mine capacity utilization can change year to year. Whereas Wyoming mine capacity utilization in 2008 was 93.3 percent (EIA 2010d), in 2006 it was approximately 86.0 percent (EIA 2007a) (more current data on productive capacity and recent declines in production levels are discussed later in this EA).

Moreover, power plants stockpile coal in the event of unexpected short-term changes in coal deliveries as well as to be prepared in the event of a more drastic disruption to coal supplies. This allows the power plant to continue operations without having to use or find more expensive alternative fuel or electricity supplies (Kaplan 2007). In 2008, total coal stocks were at 205.1 million short tons, of which 161.6 million tons were being stockpiled by the electric power sector and another 34.7 million short tons were held by producers and distributors (EIA 2010d). Graph 4.1.3 shows the trends from 1950 to 2008 in the total amount of coal stocks and the portion held by the electric power sector (EIA 2009a; EIA 2010d). The considerable variation in the amount of coal stocks across the years from 1950 to 2008 is due to economic forces such as reducing maintenance costs associated with coal inventories by decreasing the inventory, forecasted prices

[8] EIA excludes coal "estimated to be unavailable due to land use restrictions" (EIA 2010d, p. 37)

and anticipated demand, in addition to events affecting transportation infrastructure such as increasing rail congestion and weather related delays (Kaplan 2007; NERC 2007; Kelley and Osterholm 2008).

Graph 4.1.3: Total Coal Stocks and Stocks Held by Electric Power Sector, 1950-2008



Source: EIA 2009a, 2010d

In 2008, the two applicant mines, Black Thunder Mine and North Antelope/Rochelle Mine, supplied approximately 17.9 percent[9] of the national steam coal market (EIA 2010d). Based upon the information discussed above, the coal to replace these mines was feasibly available within the national coal market without additional production from new mines. New and existing mines producing non-federal coal could meet the supply shortfall if future demand warranted, given the existing 10 year lead-time for the utility markets to adjust while these two mines depleted their remaining reserves. As discussed previously, federally-administered coal was only 43.3 percent of the coal produced in fiscal year 2008, therefore anticipating mines producing non-federal coal to support demand shortfalls would make sense.

[9] The two applicant mines produced 186.2 million short tons of coal in 2008 while total US coal consumption for the electric power sector was 1040.6 million short tons (steam coal market) (EIA 2010d). The 186.2 million short tons produced is considerably lower than the 230 million short tons per year the mines have produced in the past.

Also, due to the capital investment costs within the electric power sector and expected construction times for new generation units, utilities are continually reviewing current information and data to determine best future options for generation and infrastructure on long time horizons (Hogan 2008; Barbose, Wiser, Phadke, and Goldman 2009). The complexity of decisions regarding power plant investments must also take into consideration costs associated with environmental compliance (Sandor 2001). Additionally for states with regulated electric utilities, there are requirements for utility companies to develop and submit integrated resource plans (IRPs)[10] to meet customer demand for typically the next 10 to 20 years and update them on a regular basis[11] (Chupka, Murphy, and Newell 2008; Barbose etal. 2009). These IRPs should consider and assess increased need for electricity, supply and demand chains and the variety of generation options, and transmission and distribution factors (Hirst 1992).

There is also the possibility, that facing a depletion of reserves, the applicant mines would gradually reduce production thus lessening the impact to the market that could occur with a sudden supply disruption at the end of the mine life. In any case, given that utilities continually review data and information, they would be aware of potential changes in fuel supplies, electricity demands, and would have the time and the ability to adjust given that the applicant mines had approximately 10 years' worth of reserves yet to mine in 2008.

Fuel Substitution and Coal Prices

Generation units take years to build and are anticipated to continue operations for decades (Hogan 2008; Kaplan 2008). This is partly why utilities think on long time horizons to try and forecast what different fuel source costs will be, what the demand might be and how to best provide a reliable source of electricity in the most cost-effective manner. Continued use of coal for electricity generation, as discussed above, was anticipated due to the fact that existing coal-fired power plants have limited ability to change to a completely different non-coal fuel source to address concerns over air emissions (EPRI 2000; GAO 2008; Geisbrecht and Dipeitro 2009). A GAO report in 2008 evaluated the ability to switch coal-burning power plants to natural gas and concluded that conversion is unlikely due to limited natural gas infrastructure (pipelines and storage capacities near existing coal plants) and potential regulatory and technical challenges (GAO 2008). While converting a coal-fired plant to burn only natural gas is technically feasible, GAO reports that "burning natural gas at an existing coal plant would require a pipeline with the ability to meet the plant's fuel supply requirements. If not, a new gas pipeline would have to be sited, permitted, designed, and constructed" and that "a major fuel-switching program would require a nationwide natural gas infrastructure construction program. This would require expansion of interstate and intrastate pipelines to transport increased volumes of natural gas. Furthermore, existing plants and local natural gas distribution systems would have to increase their storage capacity" (GAO 2008, p. 15).

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[10] Integrated resource plans (IRP) were defined formally in the Federal Energy Policy Act of 1992 and defines it (for electric utilities) as a "planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost" (FEPA 1992 §111(d)(19)).

[11] The frequency of updates depends on the state. A good review of state IRP requirements was done by Wilson and Peterson 2011.

Although coal-fired power plants have several options to reduce emissions such as co-firing with other lower emission fuels, retrofitting plants with carbon capture and sequestration and other technologies to reduce emissions, and refurbishing the plant to increase the plant's efficiency, these alterations can take considerable capital investment (EPRI 2000; GAO 2008; Geisbrecht and Dipeitro 2009). Instead of re-tooling existing coal-fired plants, it is often more cost-effective for utilities to utilize natural gas plants with excess capacity or build new natural gas generation units (GAO 2008). Although excess capacity at existing natural gas combined cycle power plants could potentially displace 32 percent of coal generation, it is improbable due to transmission system factors, system dispatch factors[12] and fuel source costs, supply, transportation and storage (Kaplan 2010). Therefore, even with coal's anticipated decreasing market share, in part due to increased coal power plant costs to address emissions, and increasing use of natural gas and renewables, coal is still forecasted to continue contributing to electricity generation.

Essentially, there are numerous factors that play a role in what fuel will be used for electricity generation. Assumptions that leasing the four tracts discussed in this EA would cause coal prices to drop and therefore increase coal consumption and electricity demand are contradicted by several studies. Of the fuels studied (coal, natural gas, and oil) coal demand is actually the least sensitive to coal prices (own-price inelastic) and to a lesser degree to oil and natural gas prices (cross-price inelastic) (Dahl and Ko 1998; Ko and Dahl 2001; Tuthill 2008). This indicates coal availability and the potential corresponding price decreases would likely not cause significant changes in production and consumption of coal. In fact, Ko and Dahl (2001) concluded that due to coal's price inelasticity, that even with competitive pricing coal could continue to lose market shares in the electric power sector. More recent research by EIA also supports the inelastic substitution of coal in electricity generation due to power plants being designed to operate with a particular fuel (as noted above) as well as needing to operate within certain ranges for reliability and to comply with environmental restrictions (EIA 2012). Elbakidze and Zaynutdinaova (2016) examined fuel substitution elasticities for the periods of 2001-2008 and 2009-2014 and results also confirm that even if price favors substitution to a non-coal fuel, that utilities relying on coal for electricity generation have limited ability to substitute non-coal fuels.

Greenhouse Gas Emissions

In the Wright Area EIS, the BLM analyzed greenhouse gas emissions that could result from coal production and combustion if coal is burned to generate electric power. Specifically, CO_2e[13] emissions associated with mining operations[14] were projected to increase at the Black Thunder

[12] "System dispatch refers to the pattern in which power plants are turned on and off, and their power output ramped up and down, to meet changing load patterns" (Kaplan 2010 p. 18).

[13] As discussed in the Wright Area FEIS, "[e]missions are measured as metric tons (tonnes) of carbon dioxide equivalents (CO_2e). CO_2e is a unit of measure that takes into account the global warming potential of each emitted GHG in terms of equivalent CO_2 emissions" (p. 3-325).

[14] As noted in the Wright Area FEIS, for mining operations "[e]missions inventories included from all sources, including all types of carbon fuels used in the mining operations, electricity used on site (i.e., lighting for facilities, roads, and operations and electrically powered equipment and conveyors) and mining processes (i.e., blasting, coal fires caused by spontaneous combustion and methane released from exposed coal seams)" (p. 3-324-325).

and North Antelope/Rochelle mines if the North Hilight Field, South Hilight Field, North Porcupine, and South Porcupine LBA Tracts were added to the mining operations. The increases in CO_2e emissions were expected to result from the additional fuels (especially diesel) that would be used due to the increased coal and overburden haul distances, as well as increased use of electricity and explosives related to increasing overburden thicknesses during mining operations. Table 3-24 in the Wright Area Final EIS (FEIS) (p. 3-325) indicated that for all six LBA tracts[15] analyzed, the estimated annual CO_2e emissions associated with the mining of that coal (including projected methane emissions vented from exposed, unmined coal) would be 2,502,889 tonnes as opposed to the 2007 estimated annual CO_2e emissions of 1,245,241 tonnes (please see the Wright Area FEIS for more details). The Wright Area FEIS further discussed that based upon estimates from the Center for Climate Strategies the 2007 CO_2e emissions (1,245,241 tonnes) associated with mining operations from the applicant mines (as analyzed in the FEIS) represents 2.22 percent of the 2010 state-wide CO_2e emissions. With the addition of the six LBA Tracts analyzed in the FEIS, the estimated total CO_2e emissions associated with mining operations at the applicant mines would represent 3.61 percent of the projected 2020 state-wide emissions (please see the Wright Area FEIS for more details).

Additionally, the amount of CO_2 from the combustion of the coal produced in 2008 and under the alternatives were also discussed in the Wright Area FEIS. For instance, the Wright Area FEIS states that the applicant mines produced 228.3 million tons of coal in 2008 and that "[c]ombustion of those 228.3 million tons of coal to produce electricity produced about 378.7 million tonnes of CO_2 emissions, or about 5.4 percent of the total estimated anthropogenic CO_2 emissions produced in the U.S. in 2008" (p. 4-139). The Wright Area FEIS further states that under the No Action Alternative, CO_2 emissions associated with combustion of the coal produced by the applicant mines "would be extended at about this level for up to approximately 10 years beyond 2008, while the mines recover their remaining estimated 2,483 million tons of currently leased coal reserves" (p. 4-139-141). CO_2 emissions from combustion of the coal produced are also estimated for the Proposed Action and Alternative 2, both as the total and the average per year for each specific LBA tract. Under the Proposed Action total CO_2 emissions associated with combustion of the coal produced by the four LBA tracts of interest in this EA ranged from 997.4 million tonnes (average of 158.3 million tonnes per year) for the North Porcupine tract to 437.1 million tonnes (average of 218.5 million tonnes per year) for the North Hilight Field (see Table 4-39 on page 4-140 of the Wright Area FEIS and its associated discussion for additional detail and for CO_2 emissions associated with Alternative 2). It was also noted that more rapid improvements in technologies that provide for less CO_2 emissions, new CO_2 mitigation requirements, or an increased rate of voluntary CO_2 emissions reduction programs could result in significantly lower CO_2 emissions levels than were estimated in the Wright Area FEIS.

The Wright Area FEIS also discussed the uncertainty surrounding potential programs, initiatives, and regulations to reduce greenhouse gas emissions and increased energy efficiency at the Federal, state and local levels and how that might affect future CO_2 emissions. The Wright Area FEIS also elaborated on overall projections of energy-related CO_2 emissions from several *AEOs*.

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[15] As discussed in Chapter 3, the Wright Area FEIS analyzed six LBA tracts; however, after the FEIS was completed two tracts were withdrawn per company request. Therefore CO_2e emissions discussed in this section regarding all six LBA tracts likely overestimate potential emissions of the remaining four tracts discussed in this EA.

The FEIS discussed that in the *AEO2007*, energy-related CO_2 emissions were projected to grow by about 35 percent from 2006 to 2030 (EIA 2007b). By comparison, the *AEO2008* projected energy related CO_2 emissions to grow by 16 percent, from 5,890 million tonnes in 2006 to 6,851 million tonnes in 2030 (EIA 2008b). However, *AEO2009* projected energy-related CO_2 emissions to grow by 7 percent, from 5,991 million tonnes in 2007 to 6,414 million tonnes in 2030 (EIA 2009b). The mix of fuel sources for these projections include coal, natural gas, nuclear, liquids (petroleum), hydro-power, and non-hydro renewables (wind, solar, etc.). The lower projected emissions growth rate in the *AEO2009* is due to a slower demand growth combined with increased use of renewables and a declining share of electricity generation that comes from fossil fuels (EIA 2009b). Therefore, at the time of the NEPA analysis and RODs, based upon several *AEO*'s projections which included a projected mix of fuel sources, including renewables, CO_2 emissions were projected to continue to increase through 2030.

As previously mentioned, numerous factors influence a utility's decision for best future options for generation and transmission. It has become clear that there has been an increased capacity and use of renewable sources for electricity generation in the past decade. The U.S. wind's market share has increased every year since 2001 in part due to a combination of technology and policy changes (EIA 2016; Ratner 2017). Numerous states have renewable portfolio standards and there have been several tax credits offered for renewable energy sources (GAO 2015; EIA 2016; Ratner 2017). While coal plants continue to be retired, it is not expected in the near term for renewable sources to be used regularly as a baseload generation unit (NETL 2018). Baseload generation units (or baseload plants) are those plants that utilities tend to maximize and use on a long continuous basis and have often been coal or nuclear plants and now more recently natural gas plants (GAO 2015). Due to the variable nature of many renewable sources such as wind and solar, it is difficult for utilities to utilize renewable sources as a baseload unit (GAO 2015; EIA 2017d). Since utilities need to be able to provide a reliable source of electricity to meet demand as demand occurs, the fluctuations in wind and solar generation associated with weather and seasonal changes increases reliability uncertainty (GAO 2015). This can mean that utilities would need to be able to switch to other sources for electricity generation when wind or solar is not available (GAO 2015; NETL 2018).

Overall energy related CO2 emissions have declined for six out of the ten past years and 2016 CO_2 emissions were 823 million tonnes lower than 2005 levels (EIA 2017e). Petroleum and other liquids continue to be the largest source of energy related CO_2 emissions since 1990 through 2016 (EIA 2017e). Coal has historically been the second largest source of energy related CO_2 emissions since 1990 but coal related CO_2 emissions have been declining since the 2007-2009 recession and in 2016 natural gas related CO_2 emissions exceeded coal related CO_2 emissions (EIA 2017e). Specific to the electric power market, the transition to increased use of natural gas and renewable sources has decreased overall CO_2 emissions associated with electricity generation by 24 percent from 2005 to 2016 (EIA 2017e). Forecasting into the future, *AEO2018* projects that total energy related CO_2 emissions will decrease to approximately 5,053 million tonnes in 2030 and increase to approximately 5,279 million tonnes in 2050 (EIA 2018d). Specific to coal, *AEO2018* projects that coal related CO_2 emissions will decrease to 1,279 million tonnes in 2030 and to approximately 1,250 million tonnes by 2050 (EIA 2018d). Electric power sector related CO_2 emissions are anticipated to remain relatively flat in part due to increased natural gas use and policies supporting renewable sources compared to coal (EIA

2018d). However, different fuel prices, especially for natural gas could increase the use of existing coal-fired generation units for electricity and thus coal related CO_2 emissions (EIA 2018d).

General Electricity Market and Coal Production Changes Since 2008

There is difficulty in forecasting or projecting what future electricity markets may look like given the various factors, many of which have been discussed already, that can influence it. In fact, EIA specifically states in the *AEO2010* that "[e]nergy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty" (EIA 2010a, p. ii). To highlight this difficulty in forecasting, Graphs 4.1.4 and 4.1.5 show the *AEO2010* Reference case total electricity generation projected market shares by fuel source (EIA 2010a) compared to the actual net generation[16] (all sectors) market shares by fuel source (EIA 2018b) from 2008 to 2017. Graph 4.1.4 compares actual net generation and projected generation market shares for natural gas, nuclear, and renewable sources[17] and indicates that there was considerable difference in the market share of natural gas between the projections and actual net generation use. The *AEO2010* Reference case anticipated that the use of natural gas for electricity generation would decrease to a little over 15 percent market share when in fact natural gas increased to being over 30 percent of the electricity generation market share in 2017 (see Graph 4.1.4). The market shares of renewable sources for net electricity generation were slightly lower than *AEO2010* Reference case projections from 2012 through 2016 and increased slightly over *AEO2010* Reference case projections in 2017 (see Graph 4.1.4). Nuclear has maintained approximately 20 percent market share of the net electricity generation as projected by *AEO2010* (see Graph 4.1.4).

As indicated by Graph 4.1.5, net electricity generation has seen a considerable reduction in coal market shares going from a little over 48 percent in 2008 to 30 percent in 2017 whereas the *AEO2010* Reference case had projected coal to have approximately 47 percent market share in 2017. The graphs exemplify how the electrical generation markets have changed and differ from what was anticipated.

The significant changes within electrical generation markets during the 2008-2017 time-period have occurred due to multiple forces including the economic downturn in 2007 through 2009, the shale gas boom, and growth of renewable sources in the electricity generation market (GAO 2012; Macmillan, Antonyuk and Schwind 2013; Logan, Medlock and Boyd 2015; Hibbard, Tierney and Franklin 2017; Ratner 2017). In particular, the unanticipated increase in shale gas development and production has caused a drop in price of natural gas to a point where it's competitive with coal (Macmillan et al. 2013; Ratner and Glover 2014; GAO 2015; Hibbard et

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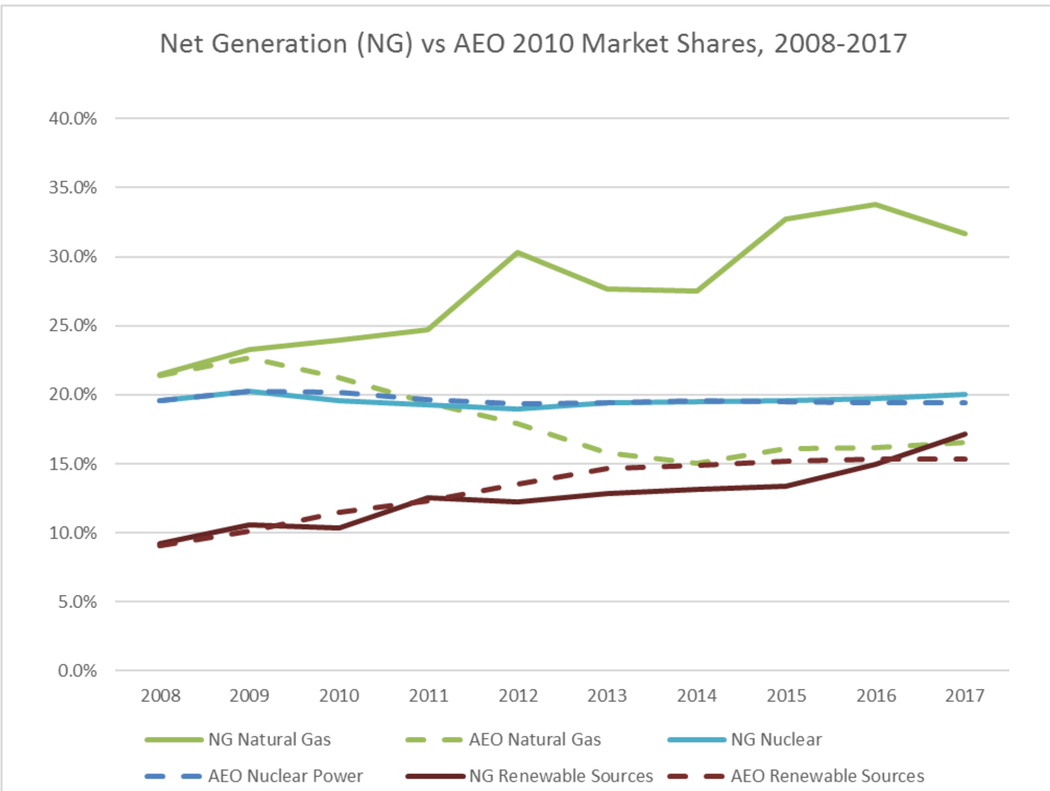
[16] Graphs 4.1.4 and 4.1.5 show *AEO2010* projections for total electricity generation by fuel source and net generation of electricity (all sectors) by fuel source. Net generation excludes the electrical energy consumed by generating stations for services, but still provides a reasonable approximation to compare to *AEO2010* total electricity generation market shares.

[17] Petroleum and "Other" sources were not compared due to the very low use of these sources, as compared to the other fuel sources, for electricity generation (EIA 2018b).

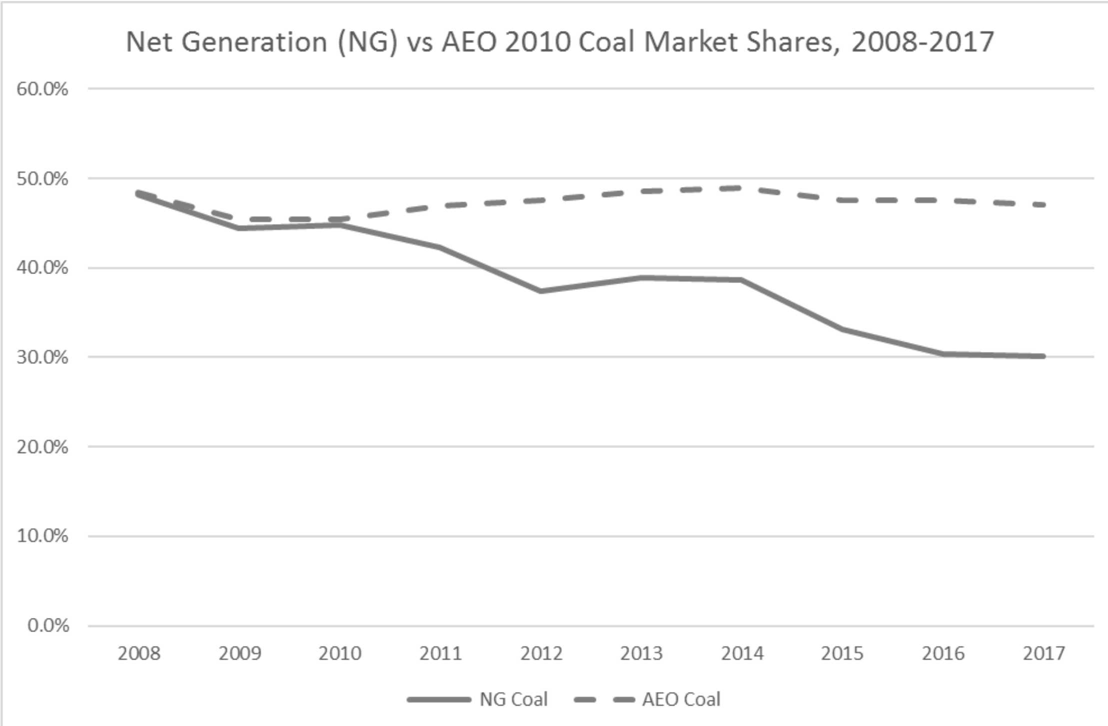
al. 2017). As indicated in Graph 4.1.6, the cost per million British thermal unit (Btu) of natural gas for electricity generation dropped significantly around 2012 which is when the market share of natural gas also saw a big increase (as seen in Graph 4.1.4). Another large increase in natural gas market shares occurred in the 2015-2016 timeframe (as seen in Graph 4.1.4) which is when costs for natural gas decreased to the point of being similar to that of coal (Graph 4.1.6). The increased sustained production of shale gas and the resulting lower prices has caused utility operators to shift power generation from higher cost coal plants to underutilized existing natural gas burning generating units or to install new natural gas units (Liang, Ryvak, Sayeed, and Zhao 2012; Campbell, Folger and Brown 2013; Hibbard et al. 2017). In fact, coal consumption for electricity generation in 2017 was at the lowest level since 1982 (EIA 2018e).

Graph 4.1.4: Net Generation (All Sectors) vs *AEO2010* Reference Case Market Shares, 2008-2017.



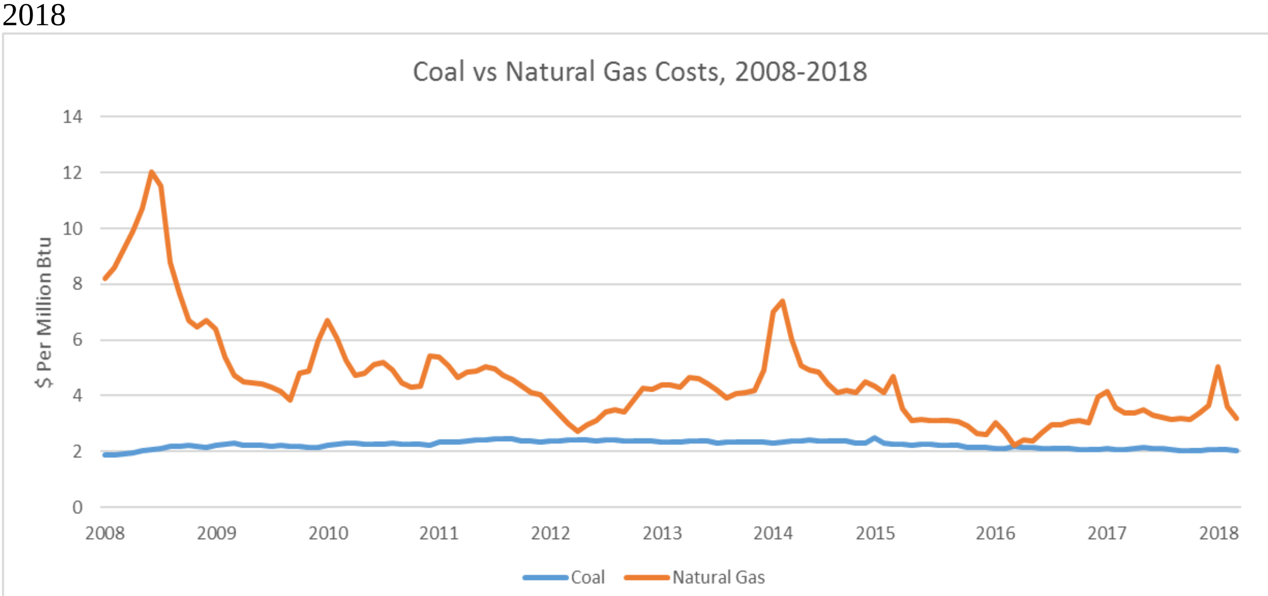
Sources: NG data from EIA 2018b, *AEO2010* data from EIA 2010a.

Graph 4.1.5: Net Generation (All Sectors) vs AEO 2010 Reference Case Coal Market Shares, 2008-2017.



Sources: NG data from EIA 2018b, *AEO2010* data from EIA 2010a.

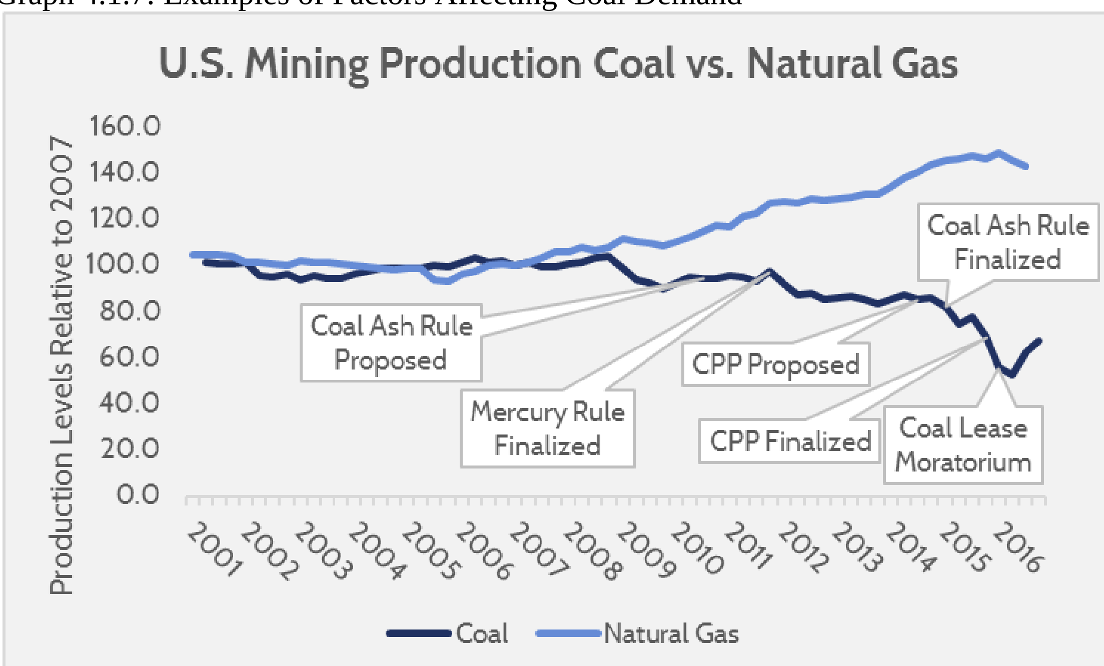
Graph 4.1.6: Costs of Coal vs Natural Gas for Electricity Generation in Nominal Dollars, 2008-2018



Source: EIA 2018h

Additional pressures, in particular proposed and finalized federal regulations, since 2008 have also affected coal production and demand as indicated by Graph 4.1.7. Many of the regulations have caused coal-fired utility operators to consider strategies for complying with the associated requirements. For example, EIA in 2014 examined operators' approaches to the Mercury and Air Toxics Rule (Mercury Rule in Graph 4.1.7) for their existing coal-fired plants and found that approximately 64 percent of the plants already had necessary environmental control equipment to comply with the rule and another 6 percent were going to add control equipment (EIA 2014). Only 9.5 percent announced plans to retire non-compliant coal-fired plants whereas over 20 percent were undecided as to upgrade/retrofit or retire their coal-fired plants (EIA 2014). Strategies for complying with the Coal Ash Rule and the Clean Power Plan (CPP) Rule may cause operators to retire additional coal-fired plants which could lead to reduced demand for coal if no new coal-fired plants are built to replace them (GAO 2012; Macmillan et al. 2013). In addition to federal regulations affecting coal use in the electricity market, various states have their own policies and programs to reduce CO_2 emissions that can include expanding renewable sources in utilities' IRPs or emissions caps that would affect utility planning and dispatching[18] of generation units (EPA 2016, Hibbard et al. 2017; Ratner 2017).

Graph 4.1.7: Examples of Factors Affecting Coal Demand



Source: https://www.americanactionforum.org/research/coal-declines-markets/

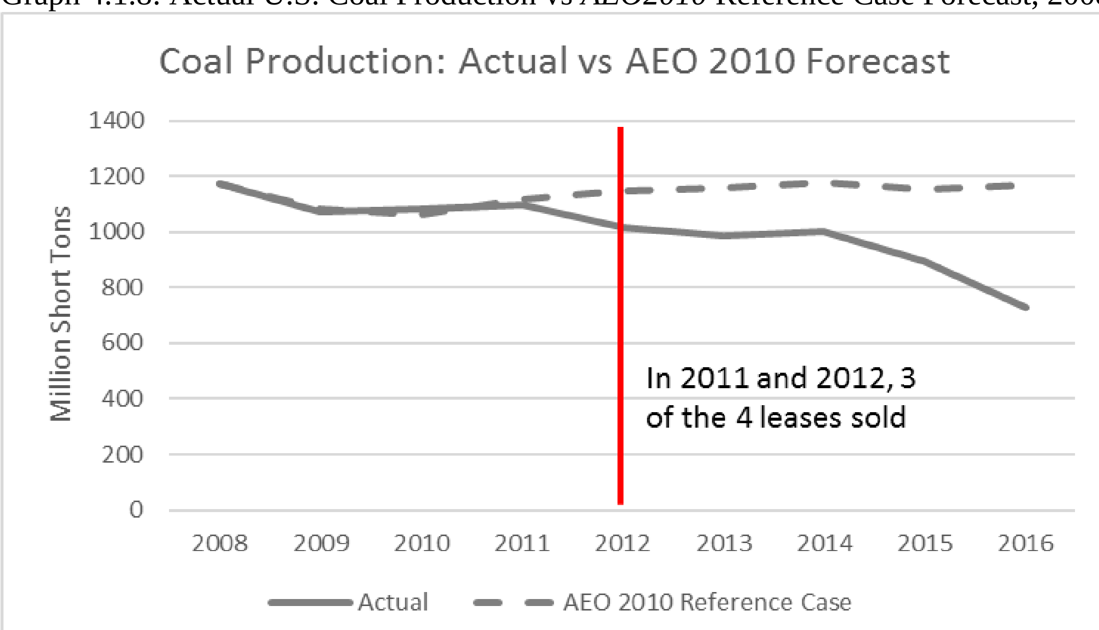
Utility companies have dealt with the uncertainty of potential future environmental regulations that could affect their operations and investment planning (Johnston et al. 2007; Barbose et al. 2009). In particular, many utility companies are incorporating carbon regulation and costs

[18] Dispatching is when a generating unit is called into service to meet electricity demand. Operators dispatch plants or generating units "with the simultaneous goals of providing reliable power at the lowest reasonable cost….plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid" (FERC 2015, p. 48).

scenarios into their long-term planning and several states actually require it as part of their IRP (Johnston et al. 2007, Luckow et al. 2016). However, the various assumptions and cost estimates used associated with potential carbon regulations differ greatly among the utilities that have attempted to incorporate carbon regulation scenarios into their long-term planning (Johnston et al. 2007; Barbose et al. 2009). Incorporation of potential carbon regulations, or other greenhouse gas emissions, and the assumptions and cost estimates used by utility companies is important because differing assumptions and costs could influence generation dispatch order as well as potentially earlier retirements of existing coal plants and the resulting additional generation needs.

Overall changes to the electricity market, the shift towards more natural gas use for electricity generation, and concerns over greenhouse gas emissions has had an effect on coal production across the U.S. There has been a downward trend in production levels that mirror the actual use of coal in electricity generation (as displayed in Graph 4.1.5). Since 2008 coal production decreased from over 1170 million short tons produced to approximately 728 million short tons produced in 2016 (Graph 4.1.8). However, the *AEO2010* Reference case forecasted coal production to remain rather stable with around 1100 million short tons produced annually during this same timeframe (Graph 4.1.8). This helps highlight the difficulty in forecasting fuel sources market shares in changing electricity markets. Note that in 2011 and 2012 when three of the four leases of interest in this EA were sold by BLM, overall coal production was decreasing in the U.S. (Graph 4.1.8). This indicates that the sale of the three leases did not increase coal production nor coal consumption for electricity generation (see Graphs 4.1.5 and 4.1.8).

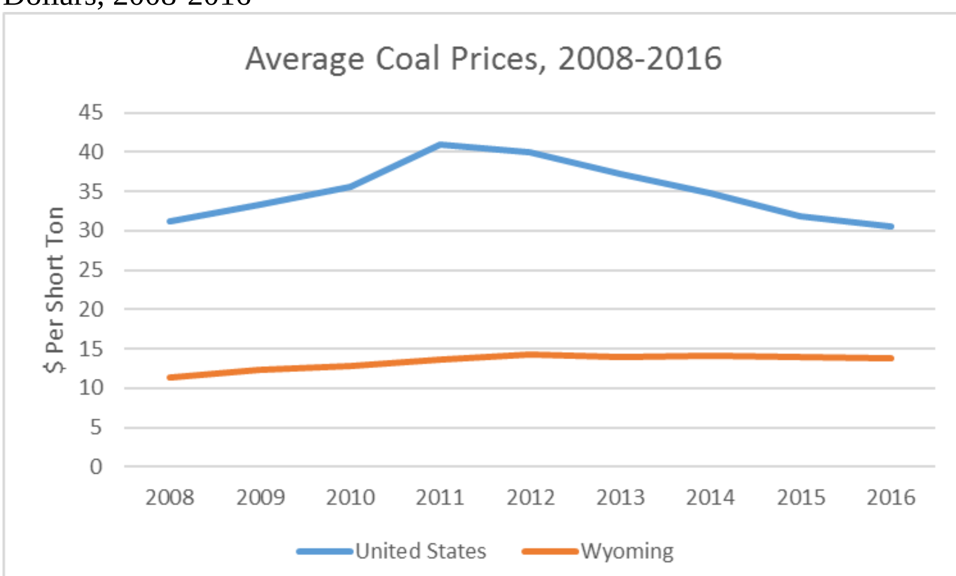
Graph 4.1.8: Actual U.S. Coal Production vs *AEO2010* Reference Case Forecast, 2008-2016



Source: Actual production from EIA 2018f, *AEO2010* data from EIA 2010a.

Moreover, the effective leasing of the three tracts by BLM in 2012 appears to have had little impact on the average sale price[19] of coal (Graph 4.1.9). While the U.S. (all coal) price (in nominal dollars[20]) in 2012 slightly decreased from $41.01 per short ton in 2011 to $39.95 per short ton, the Wyoming produced coal price actually increased from $13.56 to $14.24 per short ton in that time period (EIA 2018g). The overall trend for U.S. coal prices from 2011 to 2016 is a continued decline in price (Graph 4.1.9) while coal use for electricity generation also declines (Graph 4.1.5) which supports that coal is own-price inelastic. Prices for Wyoming produced coal tends to remain stable around the $14.00 per short ton from 2013 through 2016 (Graph 4.1.9). The fact that Wyoming coal prices slightly increased after 2011 and then tended to remain stable through 2016 after the sale and leasing of three of the four tracts, counters the idea that leasing the tracts would decrease price and thus increase consumption, which continues to support that coal is own-price inelastic. The decline in U.S. coal prices reflects decreased coal demand due to availability of natural gas at competitive prices, and more mild weather conditions and energy efficiency contributing to overall less electricity demand (EIA 2013; EIA 2017c; EIA 2018f). Additionally, EIA indicates that compliance with the Mercury and Air Toxics Standards has played a role in decreasing net coal capacity, by approximately 60 gigawatts, between 2011 and 2016 (EIA 2018d).

Graph 4.1.9: Average Coal Price for U.S. (All Coal) and Wyoming Produced Coal in Nominal Dollars, 2008-2016



Source: EIA 2018g.

With a reduction in coal demand there was also a decrease in the percent of federally-administered coal produced out of total U.S. production. The percent of federally-administered coal produced (sales volume), not including coal produced from American Indian lands, was

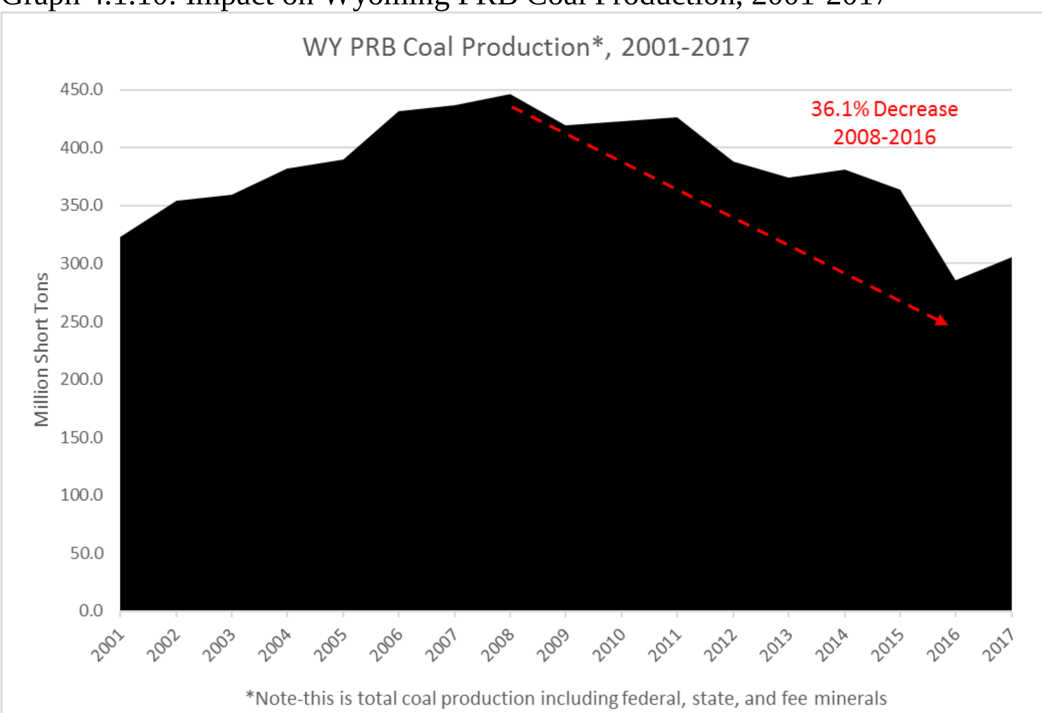
[19] The average sale price of coal is also known as the mine sales price. The mine sales price is "calculated from the free on board (FOB) value of the coal at the coal mine and excludes insurance or transportation charges" (EIA 2017a).

[20] EIA provides the coal prices in nominal dollars which is why nominal dollars is used here. When all costs are adjusted to real (or current) 2017 dollars, by using Bureau of Labor Statistics CPI, similar trends exist.

42.8 percent of total U.S. production in fiscal year 2010 and lowered to 40.8 percent by fiscal year 2014[21] (EIA 2015). Locally, decreased production also reflects that the coal mines in Wyoming had lower mine capacity utilization. As previously mentioned, Wyoming coal mines capacity utilization in 2008 was over 93 percent, however by 2009 it dropped to approximately 79 percent and in 2016 capacity utilization decreased to around 64 percent (EIA 2010d; EIA 2011; EIA 2017b).

Shifts within the electricity market and overall coal production has also affected coal production in the Wyoming portion of the PRB. For example, the Mercury and Air Toxics Rule discussed previously has "required significant improvements in emission reduction equipment to be installed at many plants and these new installations have undermined the need to burn PRB coal to take advantage of its low-sulfur content. Competitors such as Illinois Basin coals have higher heat and lower moisture contents relative to PRB coal and the combination of lower production costs; better fuel characteristics; reduced shipping costs; and the reduced need for low-sulfur fuels has allowed these challengers to gain advantages in some Midwestern, Mid-Atlantic and Southeastern markets" (Godby, Coupal, Taylor, and Considine 2015, p.32). Additionally, issues associated with railroad congestion and transportation costs have impacted the ability to get Wyoming PRB coal to markets; and, the lowered productivity due to mining deeper coal deposits have reduced production (National Research Council 2007; Godby et al. 2015). Graph 4.1.10 highlights the decreased production of 36.1 percent that occurred in the Wyoming PRB from 2008 to 2016 although there was a slight increase in production in 2017.

Graph 4.1.10: Impact on Wyoming PRB Coal Production, 2001-2017



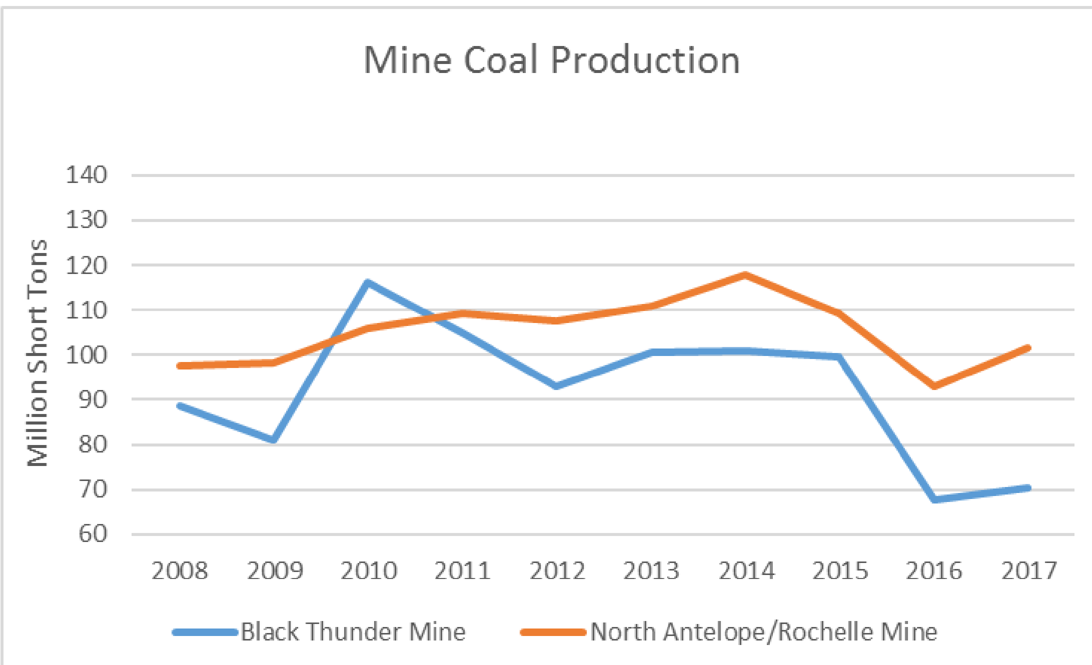
Source: U.S. BLM High Plains District Office 2018

[21] Data for fiscal year 2014 is the latest data available from the EIA that provides a breakdown of fossil fuel sales of production from federal lands (EIA 2015).

Current Production Levels at the Black Thunder Mine and the North Antelope/Rochelle Mine

There has been variation in the amount of coal produced at the Black Thunder Mine and the North Antelope/Rochelle Mine from 2008 to 2017 (see Graph 4.1.11). Although the Black Thunder Mine is permitted to produce 190 million short tons of coal per year, the most that the mine has produced during the 2008 to 2017 time period is 116.2 million short tons in 2010 and significantly reduced production to 67.9 million short tons in 2016 as indicated by Graph 4.1.11 (MSHA 2018a). Graph 4.1.11 also indicates that the North Antelope/Rochelle Mine slowly increased production from 2008 and production peaked in 2014 at approximately 118 million short tons which is still lower than the 140 million short tons that the mine is permitted to produce per year. The North Antelope/Rochelle Mine also reduced production in 2016 to only about 92.9 million short tons (MSHA 2018b). Although both mines saw increased production levels in 2017, production levels are still lower than their permitted amounts by 62.9 percent (Black Thunder Mine) and 27.4 percent (North Antelope/Rochelle Mine) (MSHA 2018a,b).

Graph 4.1.11: Black Thunder Mine and North Antelope/Rochelle Mine Coal Production, 2008 to 2017



Source: MSHA 2018a,b.

As previously mentioned, the three leased tracts of interest in this EA, South Hilight Field purchased by the Black Thunder Mine and the South Porcupine and North Porcupine tracts purchased by the North Antelope/Rochelle Mine, were approved for mining in 2013 and 2014 by WDEQ and mining is underway and ongoing at all three tracts. Mining of these tracts has not caused an increase in production since 2014 and in fact both mines have seen decreased production amounts as indicated by Graph 4.1.11.

The North Hilight Field tract remains unsold, but if leased could contribute to meeting future coal demands. The EIA anticipates that U.S. coal demand will likely remain relatively flat through 2050 averaging only 750 million short tons per year with at least 25 gigawatts of coal-fired capacity being retired between 2018 and 2020 (EIA 2018c). Coal production is forecasted to decrease until 2022 and then slightly rise until 2030 and then stabilize through 2050 (EIA 2018d). Not leasing the North Hilight Field tract does not mean coal consumption by the electric power sector would be reduced since so many other factors, as discussed throughout this EA, contribute to the fuel sources used for electricity generation.

Additionally, if U.S. coal demand is anticipated to average around 750 million short tons per year (EIA 2018c), this demand could be met by mining recoverable reserves, increasing coal mine utilization, and using existing coal stocks. At the end of 2016, there was an estimated 254,197 million short tons of recoverable reserves in the U.S., of which only 35,904 million short tons were estimated to occur in Wyoming (EIA 2017b). Furthermore, for 2016 EIA estimated that the capacity of U.S. coal mines was 1,068.0 million short tons (EIA 2017b) and if demand averages around 750 million short tons that equates to an overall U.S. mine utilization rate of approximately 70.2 percent. Although coal stocks have been decreasing since 2009, at the end of 2017 there was still 163.5 million short tons of coal stockpiled (EIA 2018b). This indicates that adequate supply of coal exists from recoverable reserves, mine capacity utilization and coal stocks to meet forecasted demand in the event that the North Hilight Field tract remains unsold. Furthermore, the lack of leasing federally-administered coal may "have opposite impacts on production, lowering production on federal lands and raising it on private land" (Krupnick, Ratledge and Zachary 2016, p. 8). Therefore, it would be feasible to think that greenhouse gas emissions from coal production and combustion for electricity generation could be similar whether or not the North Hilight Field tract is leased due to other coal being substituted to meet continued coal demands of the electric power sector.

Conclusion

In examining the analysis in this EA, the possibility exists that some coal could potentially be replaced by another fuel source due to competition. However, the switch from steam coal to other forms of electricity generation is based on many factors including the cost of the fuel, existing infrastructure (capital), and the regulatory environment.

Key points from the data and information presented in this EA support that:

At the time of the Records of Decisions were signed there was an understanding that:

1. Forecasting electricity market dynamics and thus the effect on future coal production levels involves uncertainty.
2. Coal would continue to be a fuel source for electric power generation in the US.
3. Continued use of coal for electricity generation would continue because existing coal-fired power plants have limited ability to change to a completely different non-coal fuel source to address concerns over air emissions.
4. Coal demand could be met by coal produced from other recoverable reserves, existing mines increasing their production to maximize mine capacity, or electricity generation plants could utilize existing coal stocks.

5. Coal from onshore federally-administered lands was around only 43 percent of the coal produced nationwide in 2008 indicating the majority of coal produced in the U.S. was not from federally-administered lands.
6. Electricity generating utility companies continually review current information and data on future electricity demands in order to determine best future options for generation and infrastructure on long time horizons (10 to 20 years) as well as in the short term to ensure fuel supplies in the event of possible supply disruptions.
7. The applicants of the Wright Area leases had approximately 10 years' worth of coal after 2008 to mine without these four LBA tracts. Given that, if the leases were not sold, utilities would be aware of potential changes in fuel supplies and would have the time and the ability to adjust to anticipated future market conditions.
8. Coal demand is own-price inelastic, meaning that if tracts were leased, this inelasticity indicates coal availability would not cause significant changes in production and consumption of coal for electricity generation.

Changes that have occurred in the markets since the Records of Decisions were signed include:

9. There continues to be uncertainty in forecasting electricity market dynamics and thus the effect on future coal production levels is uncertain.
10. Coal demand and consumption by the electric power sector will likely continue to decrease until 2022, slightly rise until 2030 and then level off through 2050 with an annual average amount of 750 million short tons of coal being used for electricity generation through 2050.
11. Data shows that the three lease tracts sold did not have an effect on coal production nor coal consumption for electricity generation, nor affect coal prices.
12. Reduced demand for coal has been a result of multiple factors including regulations, natural gas prices being competitive, utilities now using underutilized existing natural gas plants for electricity generation, and utilities continuing to examine IRPs and fuel sources given concerns over greenhouse gas emissions and potential future regulations.
13. There will continue to be greenhouse gas emissions from coal production and use by the electric power sector, with only around 40 percent of the coal produced nationwide being from federally-administered lands.

The Wright Area EIS concluded that the selection of the No Action Alternative of not offering the leases would not likely result in a decrease of nationwide CO_2 emissions since there were multiple other sources of coal, which we have further illuminated in this EA. Concerns that leasing these four tracts would increase the coal supply, thereby decreasing coal prices and thus increasing coal consumption and demand and related CO_2 emissions are unfounded. In fact, since three of the four tracts were leased and are currently being mined overall coal production and coal use (demand) in electricity generation has decreased. While it is true that under the law of demand 'a decrease in the own price of a normal good will cause quantity demanded to increase'; the responsiveness of how quantity demanded changes relative to a change in price is more nuanced (own-price elasticity) and depends upon numerous factors such as the availability of substitutes, length of adjustment period and the budget share spent on the good. In the case of electric power generation, the consumption of coal is generally, relatively unresponsive to prices (inelastic). Basically, the inelasticity of coal in electricity generation indicates that increases in the availability and corresponding decreases in prices may not trigger significant changes in production and consumption of coal. As discussed in the EA, electricity generation is typically price inelastic because many power plants are designed to operate with a particular fuel type and must operate within certain ranges because of reliability and environmental restrictions.

Overall electricity generation related CO_2 emissions decreased by 24 percent from 2005 to 2016 indicating that offering the leases did not increase nationwide CO_2 emissions. Greenhouse gas emissions from coal production and combustion for electricity generation could be similar whether or not the North Hilight Field tract is leased due to other coal (recoverable reserves, increased mine capacity utilization, and existing coal stocks) being substituted to meet continued coal demands, albeit as a smaller market share, of the electric power sector. Essentially, because offering the leases has not increased greenhouse gas emissions, it supports BLM's conclusion that because coal is own-price inelastic, not offering the leases would not significantly affect nationwide greenhouse gas emissions.

Chapter 5

Consultation and Coordination

Table 5-1. Project Contributors and Reviewers

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Greg Adams	Team Lead, Coal Analysis	U.S. Energy Information Administration
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Appendix A: National Energy Modeling System (NEMS)

Housed under the Department of Energy, the U.S. Energy Information Administration (EIA) is the principal agency responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy, energy markets, and environmental interactions (EIA 2018a). EIA programs cover data on energy sources such as coal, petroleum, natural gas, renewable and alternative fuels, and nuclear energy; energy uses such as electricity, consumption and efficiency; and energy flows (EIA 2018a). EIA provides impartial energy information that is used by federal, state, and local governments, the academic and research communities, as well as by businesses and industry organizations (EIA 2018b). It is a requirement that EIA remain policy-neutral (EIA 2009).

As part of its *Annual Energy Outlook* publication, EIA[22] designed and implemented the National Energy Modeling System (NEMS). NEMS is an inter-regional, inter-sectoral, dynamic model using economic, geological, demographic, and other inputs' trends, and assumptions to provide statistical projections related to U.S. energy markets. Specifically, NEMS "projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics" (EIA 2009, p.1). The value of NEMS is that it can provide a consistent framework for numerous complex interactions to evaluate potential responses to differing policies or public initiatives (EIA 2009). The primary use for NEMS is to produce the *Annual Energy Outlook (AEO)*, a yearly EIA publication that is posted publicly to their website. NEMS is also used for special requests related to large-scale scenario analyses, primarily from the U.S. Congress.

As noted in the EA, the BLM relied upon the *Annual Energy Outlook 2010* (*AEO2010*) for understanding what potential electricity demands and generation needs may be through 2035. *AEO2010* included the Reference case, which is the "business-as-usual trend estimate, given known technology and technological and demographic trends" (EIA 2010a p. ii) as well as 38 sensitivity cases[23] or scenarios, five of which were discussed in the EA[24] (EIA 2010a). The *AEO2010* published NEMS projections over a 25-year time horizon, a period in which the economic structure and nature of energy markets can be sufficiently understood with regional detail (EIA 2010b). *AEO2010* results are based upon a version of NEMS that represented current legislation and environmental regulations as of October 31, 2009[25] (EIA 2010a,b).

The NEMS model consists of 12 component modules which represent different fuel supplies, end-use consumption, conversion sectors, macroeconomic factors, and international factors as well as an integrating module that executes each of the component modules (see Figure 1). The

[22] NEMS was developed and is maintained by the Office of Integrated Analysis and Forecasting (OIAF) of EIA (EIA 2010a).
[23] A brief description of the various *AEO2010* cases is provided in Table E1 of EIA 2010a and Table 1.1 in EIA 2010b.
[24] The EA explicitly discussed the *AEO2010* Reference case, the Low Economic Growth case, the High Economic Growth case, the Low Coal Cost case, and the High Coal Cost case.
[25] Appendix A of EIA 2010b provides information on the handling of Federal and selected State legislation and regulation in *AEO2010*.

modular nature of NEMS allows for sector specific assumptions, methodologies and details to be incorporated as well as for revisions to and testing of modules individually. Each component module incorporates the effects, including costs, of legislation and environmental regulations that affect that specific sector or module and accounts for SO_2, NO_x, and mercury associated with electricity generation and combustion related CO_2 emissions (EIA 2010a). Essentially, NEMS, through the modules, balances out energy supply and demand for each fuel source and consuming sector while accounting for competition between differing fuels and fuel supplies on an annual basis (EIA 2010b,e).

Due to differences in energy supply, demand, and conversion factors across the United States, NEMS takes a regional approach to reflect regional differences in energy markets and transportation flows (EIA 2010b). The level of regional detail depends on the specific modules. For the end-use demand modules the regional level is the nine U.S. Census divisions, the North American Electric Reliability Council (NERC) regions and subregions for electricity, the Petroleum Administration for Defense Districts (PADDs) for refineries, and production and consumption regions specific to oil, natural gas, and coal supply and distribution[26](EIA 2010 a,b). Given the interactions between modules, *AEO2010* provides most results for the nation, the aggregated nine U.S. Census divisions and/or the NERC regions and subregions, depending on the specific sector and results being evaluated.

Most modules have several submodules which encompass different key functional areas. For example, the Coal Market Module (CMM) which provides annual forecasts of prices, production, and consumption of coal, is comprised of the Coal Production Submodule (CPS) for coal production, and the Coal Distribution Submodule (CDS) for both domestic coal distribution and international coal trade (EIA 2010c). For the *AEO2010*, there were 14 identified U.S. coal supply regions represented in the CPS and 16 domestic coal demand regions in the CDS[27] (EIA 2010c). The coal of the different supply regions is categorized by four thermal grades (corresponding to coal grades/ranks), three sulfur emissions grades, and mining type (EIA 2010c). The CMM also incorporates environmental-, technological-, and transportation-related constraints that combine to produce a distribution pattern “which differs from unconstrained delivered cost minimization[28]” (EIA 2010c, p.71). Although this is a very simplistic depiction of the CMM, it is meant to help demonstrate that EIA has given considerable thought and foresight into the numerous interacting factors that influence the U.S. coal market and its supply, transportation, and consumption components. These interacting factors include the specific type and emission specific information associated with Wyoming Powder River Basin coal production, mine labor productivity, and transportation related costs (for more specific information on the NEMS CMM, please review EIA 2010c).

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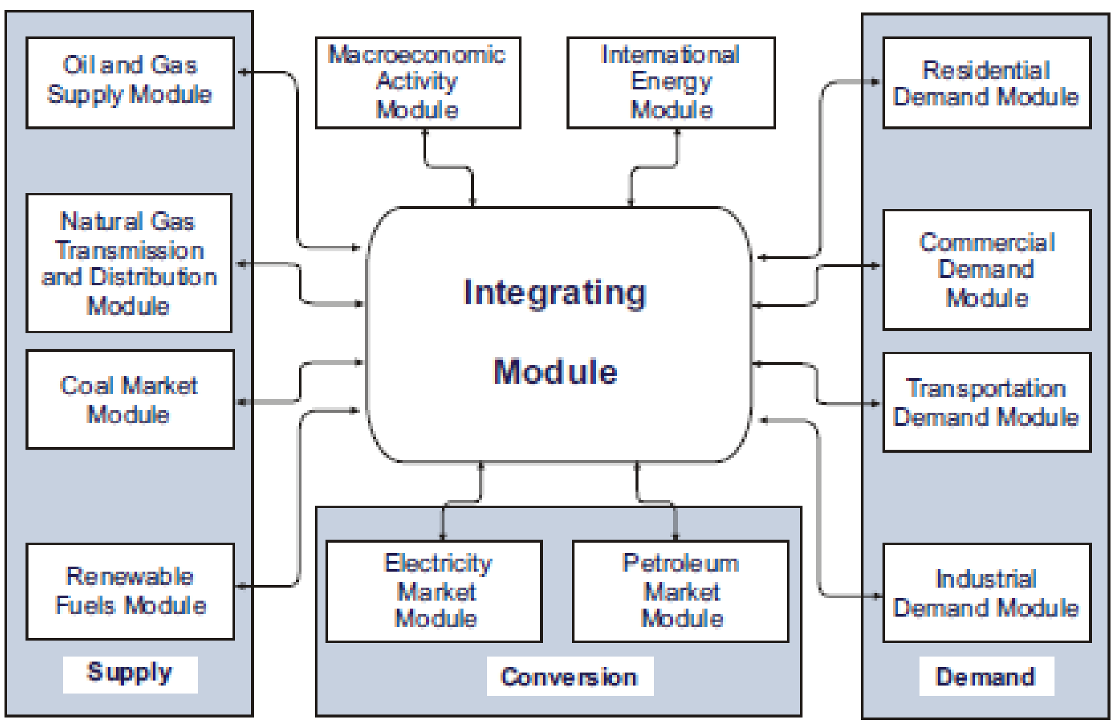
[26] Specific regional maps are provided in Appendix F of EIA 2010a. Additionally, Table 2 of EIA 2010e also provides a summary of NEMS modeling detail for the various energy sectors including the applicable regions.
[27] The CDS also includes 17 geographic exporting regions (5 of which are in the U.S.) and 20 importing regions (4 of which are in the U.S.) (EIA 2010c). Note that the CDS projects “U.S. imports required to satisfy coal demand in the U.S. established by the industrial and electricity models” (EIA 2010c, p. 146).
[28] EIA 2010c further elaborates on this by stating, “[e]nvironmental regulation and technological inflexibility combine to restrict the types of coal that can be used economically to meet many coal demands, thus reducing the consumer's range of choice. Supply reliability and local limits on transportation competition combine to restrict where, in what quantity, and for how long a technically and environmentally acceptable coal may be available” (p. 71).

However, the CMM does not take into account coal stock builds and drawdowns at power plants and mines, because it integrates the NEMS assumption that the "supply and demand for all fuels will balance for all projection years" (EIA 2008, p. 3). This led to underestimations of coal production for specific years in several *AEO*s through 2008 (EIA 2008). Additionally, NEMS Reference case projections over the mid-to-long-term assume a number of current energy market parameters projected into the future, when they may be subject to change. While this is useful for understanding the interaction and general relationship between different variables under certain assumptions, it does not account for the potentially disruptive impact of unanticipated changes affecting energy markets. As a result, observed levels of U.S. steam coal consumption have been less than what previous versions of the *AEO* have projected. This is due to the unforeseen drop in electricity demand that occurred during the recession of 2007-2009, or the unforeseen technological improvements that have led to increased U.S. natural gas production during the shale boom (EIA 2017).

Figure 1. National Energy Modeling System



Source: EIA 2010b p. 2

The other module of interest for this EA is the Electricity Market Module (EMM) which reflects "the capacity planning, generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, natural gas, and biomass; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand" (EIA 2010d p.7). The EMM contains four interacting submodules—Electricity Load and Demand (ELD), Electricity Capacity Planning (ECP), Electricity Fuel

Dispatch (EFD), and Electricity Finance and Pricing (EFP)[29] (EIA 2010d). As was discussed in the EA, electric utility markets are quite complex with a myriad of factors playing a role in capacity planning and fuel use decisions. The EMM has incorporated most of these factors[30]. Essentially, through NEMS and the EMM, EIA attempts to represent potential decision-making by electric utilities given current and projected generation capacity, technological advancements, fuel source supplies and transportation, electricity transmission, and environmental regulations.

Some of the data and information incorporated into the EMM include data on existing electricity generation capacity by fuel source, known and anticipated coal and nuclear plant retirements, electricity generation construction costs, operation and maintenance costs, new technologies, and renewable energy capacity related to State renewable portfolio standard (RPS) mandates or similar laws as integrated into the Renewable Fuels Module (RFM) (EIA 2010d). It should be noted that although the EMM incorporates State-level RPS, the EMM is divided into multi-state regions and therefore is not a state-level model. The EMM must thus approximate State-level compliance based upon this regional breakout (EIA 2010a). Although the RFM is a separate module from EMM, there are considerable interactions between the two modules, which "must be run together" (EIA 2010f p. 7). Some of the inputs to the EMM from the RFM include the existing capacity of renewable energy, location, generating size, operational and maintenance costs, and cost and time of construction of new renewable capacity (for more specific information on the NEMS RFM, please review EIA 2010f).

There are also numerous interactions between the CMM and the EMM. Specifically, the "CDS [a submodule of CMM] provides detailed input information to the EMM including coal contracts, coal diversity information (subbituminous and lignite coal constraints), transportation rates, and coal supply curves. The EMM uses this information to develop expectations about future coal prices and coal availability and allows the EMM to make improved coal planning decisions" (EIA 2010c, p. 69). Furthermore, the EFD submodule of the EMM incorporates environmental considerations, like emission restrictions for SO_2, NO_x, and mercury. The EMM allocates fuel dispatching at minimum cost while considering these restrictions, in addition to engineering constraints. Therefore, the EFD interacts with the CMM in order to "consider the rank of the coal and sulfur and mercury contents of the fuel used when determining the optimal dispatch. In that way the EFD and CMM can more easily achieve convergence to the optimal coal consumption" (EIA 2010d p. 109). Unlike SO_2 and mercury emissions, NO_x emissions depend on power plant design and not coal type (EIA 2010d). Figure 2 helps convey the complexity involved within the EMM as discussed above and its interrelated nature to other NEMS modules.

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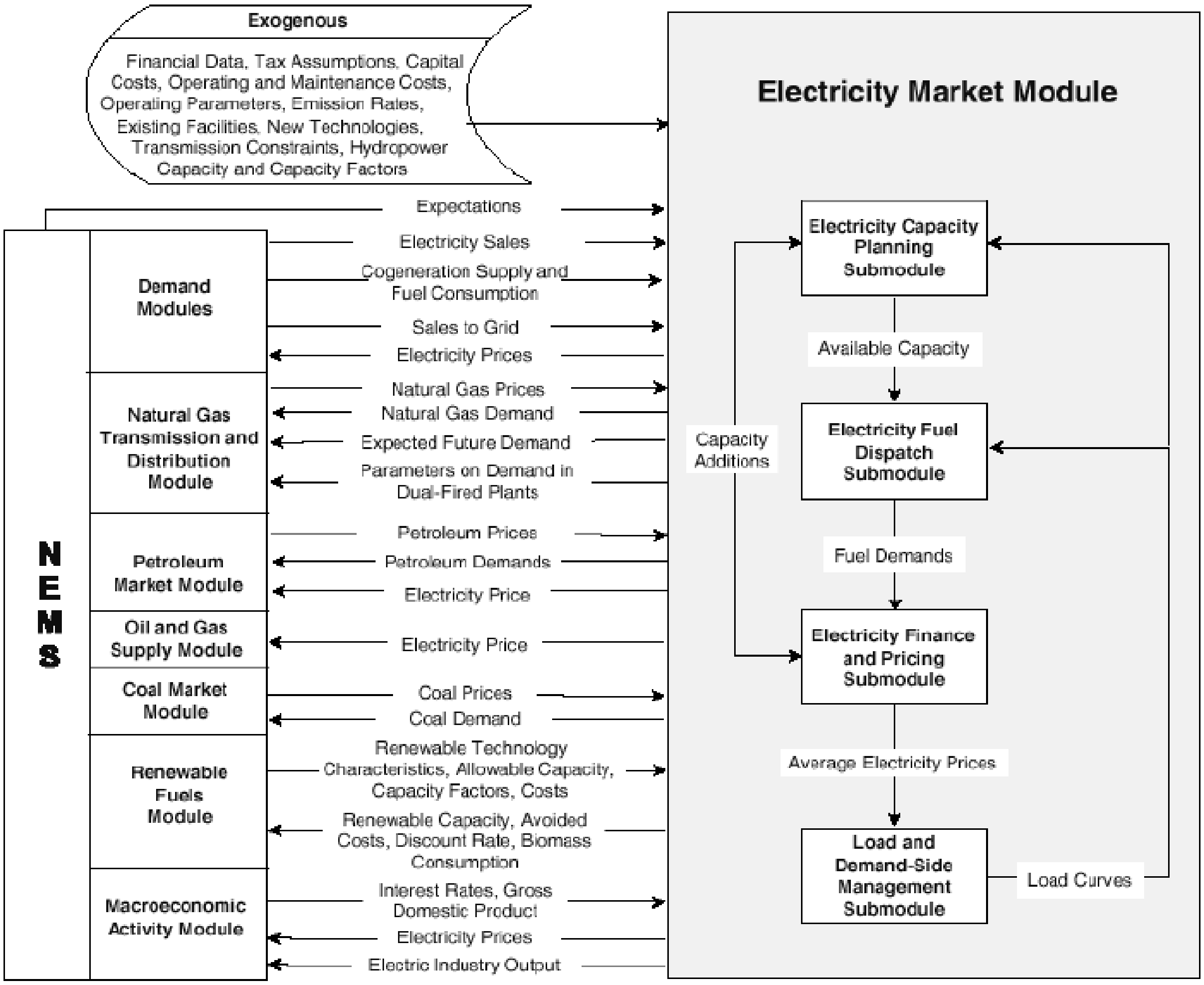
[29] Furthermore, the "solution to the submodules of the EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule" (EIA 2010d p. 7).
[30] Not all factors that play a role in utility decision-making can be anticipated, nor can potential future technological developments, electricity use/demand, and potential legislation be known. However, *AEO2010* didn't necessarily ignore these "unknowns" but instead provided projections through the various "sensitivity cases."

Figure 2. Electricity Market Module Structure



Source: EIA 2010d, p. 10

Constraints for Using NEMS for a BLM Coal Lease Project

NEMS is a high level, complex model designed for large scale (national or regional) use for examining the components of the U.S. energy system and the various interactions between energy, economics, and the environment for the mid- and long-term futures (EIA 2010c). Although the EIA makes the NEMS available for non-EIA entities to use, it does not include the parts of the model that are linked to expensive proprietary software and data unless licenses to those sources are obtained (EIA 2009, 2018c). Additionally, the EIA (2018c) notes that "[m]ost people who have requested NEMS in the past have found out that it was too difficult or rigid to use" (p.1). EIA (2018d) indicated to BLM that mostly large institutions have attempted to run the complex NEMS model, including:

- Booz Allen Hamilton, which used NEMS as a contractor for the DOE's for the National Renewable Energy Laboratory (NREL);
- The Electric Power Research Institute;

- OnLocation, Inc, which contracts with EIA on NEMS and applies NEMS in its energy consulting work, including several DOE program offices and labs;
- Rhodium Group, which uses NEMS to produce private studies and in work for clients including the DOE Office of Policy and International Affairs;
- Leidos (SAIC), which contracts with EIA on NEMS and applies NEMS to work with a number of clients, including the Canadian government, and energy trade associations such as the National Gas Council; and,
- The Union of Concerned Scientists, which has applied NEMS for energy and environmental policy analysis.

Some of the NEMS modules or components of those modules can run individually, without the need for inputs from interactions with other modules (EIA 2018c). However, the Coal Market Module (CMM) is not one of these modules, since it requires data inputs from multiple other modules and EIA designed it to interact with the Integrating NEMS module (EIA 2010c).

NEMS, as complex as it is, has limitations if used by the BLM for a specific coal leasing project in its current state. Although EIA provides brief instructions for running NEMS, given the complexity of the programming and structure of NEMS, potential modifications would likely require EIA to make them, however, "EIA does not have a budget to support the outside use of NEMS" (EIA 2018c p. 4). Additionally, given the national and regional scale of the various components of the modules, it would be difficult to approximate the more localized effects for a specific coal lease since the Coal Production Submodule (CPS) does not disaggregate its 14 supply regions into smaller areas or leases. Moreover, a potentially greater limitation of NEMS for use by the BLM is that NEMS does not distinguish between federally-administered coal versus state administered and private coal leases (Krupnick, Ratledge and Zachary 2016). As such, NEMS would not account for potential substitution of state or private coal in the energy markets and associated emissions if federally-administered coal goes unleased (Krupnick, Ratledge and Zachary 2016). Without the EIA specialists for each module modifying and running the model[31], NEMS is too cumbersome and costly for the BLM to run on its own for smaller individual coal leasing projects[32].

However, even though the BLM did not run the NEMS model for this specific coal leasing project, NEMS results were considered. The EIA based its *AEO2010* projections on NEMS results that reflected what might happen given the various assumptions and methodologies used for each scenario or case (EIA 2010a). The *AEO2010* projections for the various cases examined fuel supplies, location and transport of fuels, the potential for increased renewable generation, electricity demand and existing and projected generation capacity, transmission factors and fuel

[31] NEMS generally requires two to three EIA specialists to run each module for *AEO* projections.
[32] Krupnick, Ratledge and Zachary 2016 further expand on the complexities of NEMS by saying the "comprehensiveness [of NEMS] comes at the cost of having outputs that can be hard to interpret…[m]oreover, NEMS's comprehensiveness and complexity often mean that changes to one part of the model necessitate changes to other parts, presenting coordination challenges and contributing to further delays" (p. 7). This further supports BLM's assertion of NEMS being too cumbersome and costly to run for individual coal leasing projects.

dispatching decisions for electricity generation and the potential for fuel switching in existing plants. The BLM did not focus solely on the *AEO2010* Reference case. Rather, the BLM evaluated the range of cases analyzed and discussed the five cases that were thought to be most relevant to the EA. Additionally, the EIA compares the *AEO2010* Reference case to projections produced by other organizations and entities which allows for a broader perspective on what future energy markets may look like (EIA 2010a) which the BLM also considered.

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