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Regulatory Impact Analysis of the Stream Protection Rule

July 2015

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TABLE OF CONTENTS

LIST OF ACRONYMS AND ABBREVIATIONS

AOC	Approximate original contour
AVS	Applicant/Violator System
CCR	Coal combustion residues
CHIA	Cumulative hydrologic impact analysis
Corps	Army Corps of Engineers
CSAPR	Cross-state Air Pollution Rule
CWA	Clean Water Act
DRB	Demonstrated reserve base
EGUs	Electricity generating units
EIA	U.S. Energy Information Administration
EIS	Environmental impact statement
EPA	Environmental Protection Agency
ERR	Estimated recoverable reserves
EVA	Energy Ventures Analysis
GHGs	Greenhouse gases
IRFA	Initial Regulatory Flexibility Analysis
LEDPA	Least environmentally damaging practicable alternative
MSHA	Mine Safety and Health Administration
MTR	Mountaintop removal
MW	Megawatts
NOAAS	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OMB	Office of Management and Budget
OSMRE	Office of Surface Mining Reclamation and Enforcement
RCRA	Resource Conservation and Recovery Act
RFA	Regulatory Flexibility Act
RIA	Regulatory impact analysis
RPS	Renewable Portfolio Standards

SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SBZ	Stream Buffer Zone
SMCRA	Surface Mining Control and Reclamation Act of 1977
SRA	State Regulatory Authority
TDS	Total dissolved solids
UMRA	Unfunded Mandates Reform Act
USGS	U.S. Geologic Survey

EXECUTIVE SUMMARY

The Office of Surface Mining Reclamation and Enforcement (OSMRE) is proposing to revise its regulations to more fully implement the Surface Mining Control and Reclamation Act of 1977 (SMCRA) (30 U.S.C. §§ 1201-1328). These proposed revisions seek to improve the balance between the Nation's need for coal as an essential energy source and the protection of streams, fish, wildlife, and related environmental values from the adverse impacts of coal mining.

The purpose of this regulatory impact analysis (RIA) is to describe the economic and social costs and benefits that will result from the proposed Stream Protection Rule (Proposed Rule). It is intended to satisfy the requirements of Executive Order 12866 (E.O. 12866) – *Regulatory Planning and Review* (1993, as amended by Executive Order 13563 (2011)). Executive Order 12866 directs Federal agencies to consider the costs and benefits of available regulatory alternatives and to select approaches that maximize net benefits, unless a statute requires another regulatory approach.

The analytic scope of this RIA includes a range of measures describing the impacts forecast to result from the Proposed Rule, including the following:

- Environmental and human health impacts;
- Changes in employment and labor income;
- Energy market effects (i.e., changes in coal production and pricing, and impacts on electricity generators);
- Compliance costs incurred by the coal mining industry;
- Changes in coal market welfare (i.e., changes in producer and consumer surplus);
- Changes in economic activity; and
- Other impacts assessed under various Federal statutes or Executive Orders.

These impacts are discussed further below. In some cases, we are able to provide monetary estimates of the forecast impacts of the Proposed Rule. In other cases, best available information and methods do not support monetization. In these cases, we quantify the impact in non-monetary terms. In cases where neither monetization nor quantification is possible, we provide a qualitative description of impacts. Exhibit ES-1 presents a summary of the impacts of the Proposed Rule.

EXHIBIT ES-1A. SUMMARY OF BENEFITS AND COSTS OF THE PROPOSED RULE

CATEGORY	IMPACT OF PROPOSED RULE
Environmental Impacts (Annual)	• Fewer stream miles adversely impacted, improved water quality (e.g., pH, selenium, TDS) within watershed. Potential for beneficial impacts to groundwater quality and quantity. Quantified estimates of annual impacts to water resources include: o Water quality improvements to 292 stream miles downstream of mining activities; o 29 additional stream miles restored; o 4 stream miles not filled; o 1 downstream preserved stream mile (stream avoided by mining); • Reduced impacts to aquatic riparian and forest communities, including habitat enhancements for threatened and endangered species. Quantified estimates of annual impacts include: o 2,811 acres of forest improved (subject to additional requirements for reforestation); o 20 additional acres of forest preserved (avoided by mining); • Additional carbon storage associated with reforestation and forest improvements; reduced air pollutant emissions due to overall reduction in coal mining activity. • Potential for increased benefits to public from recreational opportunities and improved aesthetics; specifically increased quality or quantity of recreational fishing, hunting, wildlife viewing, or hiking opportunities.
Human Health Impacts	• Reduced exposure of the public to contaminants in drinking water.
Forecast Change In Coal Production From Baseline Forecast	• 1.9 million tons annual reduction (0.18% of baseline production) o 1.0 million tons surface (0.15% of baseline surface production) o 0.8 million tons underground (0.23% of baseline underground production)[1]
Forecast Compliance Cost (Annualized)	• $52 million industry-wide[2] o $45 million surface o $7.0 million underground
Forecast Market Welfare Impacts Of Higher Coal Prices and Change In Demand For Coal (Annualized)	• $34 million reduction; o Includes estimated cost savings on coal transportation to electricity generating stations.
Change in Coal Prices (Study Period Average)	• Central Appalachia (Low Sulfur): 1.2 percent increase • Northern Appalachia (Pittsburgh Seam): 0.2 percent increase • Illinois Basin (Illinois): 0.5 percent increase • Powder River Basin (High Btu): 0.3 percent increase • Rocky Mountains (Utah): 0.3 percent increase
Change in Electricity Production Cost (National Average over Study Period)	• 0.1 percent increase

Notes:

[1] An analysis of longwall mining finds that significant underground mineable reserves exist in areas where material damage to the hydrologic balance (permanent stream loss) outside the permit area would not be expected to occur. Therefore, the analysis does not anticipate that the rule would reduce the overall volume of longwall mining activity.

[2] Compliance costs represent approximately 0.1 percent of current industry-wide revenues. Compliance costs include government costs ($0.1 million, annualized).

EXHIBIT ES-1B. SUMMARY OF DISTRIBUTIONAL IMPACTS OF THE PROPOSED RULE

CATEGORY	IMPACT OF PROPOSED RULE
Forecast Change in Employment (Full-time Equivalents (FTEs), Annual)[1]	• Production-related employment impacts over baseline projections range during the study period from a reduction of 590 FTEs to a reduction of 41 FTEs with an average annual reduction of 260 FTEs. • Compliance-related employment impacts over baseline projections range during the study period from an increase of 210 FTEs to 270 FTEs with an average annual increase of 250 FTEs.
Forecast Change In Severance Taxes (Annualized)	$2.5 million reduction

[1] These numbers include only direct job effects. The reported range reflects year-to-year variability in the underlying modeled forecasts. For context, the U.S. Energy Information Administration reported 2012 employment in the coal industry to be approximately 90,000.

NEED FOR REGULATORY ACTION

The need for this Federal action is to improve implementation of SMCRA to ensure protection of the hydrologic balance, and reduce impacts to streams, fish, wildlife, and related environmental values. OSMRE has identified several subcomponents of that need. First, there is a need to clearly define the point at which adverse mining impacts on groundwater and surface water (both of which provide streamflow) reach an unacceptable level; that is, the point at which they cause material damage to the hydrologic balance outside the permit area. Second, there is a need to collect adequate premining data about the site of the proposed mining operation and adjacent areas to establish a comprehensive baseline against which the impacts of mining can be compared. Third, there is a need for effective monitoring of groundwater and surface water during and after mining and reclamation activities to provide real-time information on the impacts of mining and to enable prompt detection of any adverse trends and implementation of corrective measures before it is either too late to take remedial measures or exceedingly costly to do so. Fourth, there is a need to ensure protection or restoration of perennial and intermittent streams and related resources including fish and wildlife, especially within the headwaters streams that are critical to maintaining the ecological health and productivity of downstream waters. Fifth, there is a need to ensure the use of objective standards in making important regulatory and operational decisions with a potential impact on perennial and intermittent streams. Sixth, there is a need to ensure that permittees and regulatory authorities make use of advances in information, technology, science, and methodologies related to surface and groundwater hydrology, surface-runoff management, stream restoration, soils, and revegetation.

SUMMARY OF THE PROPOSED RULE

The Proposed Rule is based on 11 principal regulatory elements defined by OSMRE, as summarized in Exhibit ES-2. For ease of discussion and analysis, OSMRE has further organized these 11 principal rulemaking elements into four "functional groups" that combine elements with common or related characteristics. The functional groups and major elements consist of the following:

- Protection of the hydrologic balance;
  - Baseline data collection and analysis,
  - Monitoring during mining and reclamation,
  - Material damage definition, and
  - Corrective action thresholds
- Activities in or near streams;
  - Stream definitions,
  - Mining through or diverting streams, and
  - Activities in or near streams
- Approximate original contour (AOC) and AOC variances; and
  - Surface mine and fill configuration, and
  - Approximate original contour requirements
- Postmining land use and enhancement
  - Revegetation and soil management, and
  - Fish and wildlife protection and enhancement.

Chapter 1 contains detailed information on the requirements of the Proposed Rule.

EXHIBIT ES-2. MAJOR ELEMENT DEFINITIONS

MAJOR ELEMENT	ELEMENT DEFINITION
Baseline Data Collection & Analysis	The extent to which each alternative provides accurate hydrologic characterization including baseline data on hydrology, geology, and aquatic biology to enable the Regulatory Authority to make better permitting decisions.
Monitoring During Mining & Reclamation	The extent to which each alternative addresses requirements for monitoring to identify conditions that could lead to material damage to the hydrologic balance.
Material Damage Definition	The extent to which each alternative provides a definition that prevents an unacceptable level of adverse impact to the hydrologic balance outside the permit area.
Corrective Action Thresholds	The extent to which each alternative requires setting corrective action thresholds for parameters related to potential material damage to the hydrologic balance.
Stream Definitions	The extent to which each alternative provides a common definition of perennial, intermittent, and ephemeral streams to allow greater clarity and protection.
Mining Through or Diverting Streams	The extent to which each alternative addresses conditions under which mining through a stream would be allowed.
Activities In or Near Streams	The extent to which each alternative addresses the circumstances under which an operator could engage in mining or mining-related activities in or near a stream, including placement of excess spoil or coal waste.
Surface Mine and Fill Configuration	The extent to which each alternative incorporates landforming principles into reclamation plans requiring post-mined land to more closely resemble the pre-mining landscape.
Approximate Original Contour Requirements	The extent to which each alternative ensures that AOC variances meet safety, hydrologic, and post-mining land use criteria and that they are consistent with post-mining land use and are achievable and feasible.
Revegetation & Soil Management	The extent to which each alternative requires (1) soil reconstruction in a manner that will restore or improve the site's capability to support native forest; i.e., maintain or improve the site index, and (2) requires revegetation with native species in a manner that will restore native ecosystems.
Fish & Wildlife Protection & Enhancement	The extent to which each alternative minimizes disturbances to or adverse impacts on fish, wildlife, and related environmental values and requires enhancement of those resources.

Source: Adapted from SPR EIS Chapter 2

This Proposed Rule comprises selected primary stream protection elements of the other action alternatives analyzed. These elements include: defining material damage to the hydrologic balance outside the permit area, enhancing baseline data collection and analysis, expanding water and stream monitoring requirements, requiring restoration of the ecological function of perennial and intermittent streams that are mined through, requiring fish and wildlife offsets for perennial and intermittent stream reaches buried by excess spoil or coal mine waste, placing additional restrictions on mountaintop removal mining operations and steep-slope mining operations that seek variances approximate original contour restoration requirements, and requiring revegetation with native species, including reforestation of previously forested areas.

Note that, if finalized, the requirements of the Proposed Rule are expected to be implemented in states with Federal programs (currently Tennessee and Washington) and Indian lands in late 2016. States with primacy are expected to implement the Proposed Rule in early 2020. After the effective date of the final regulations, the requirements will apply to new permits and renewed permits (within five years). Given a lack of detailed information on the expected future permitting cycle for mines, we assume that the new requirements of the Proposed Rule will be fully implemented for all production starting in 2020. This assumption will result in overstating both the expected costs and benefits of the rule during the initial five years of the analysis period and omitting a small amount of costs and benefits prior to 2020 on mines with new or renewed permits under Federal programs.

MODEL MINES APPROACH

Coal mining operations vary from region to region, within a region, and within a mining type in a given region. In addition, the population of active mines is expected to change over time; as such, the precise location and operating characteristics of the population of future mines cannot be forecast based on publicly available data.

Given a lack of a mine-specific forecast of future operations, it is not possible to forecast for specific existing or future mines how operations will change under the Proposed Rule. Instead, this analysis relies on a "model mine" analysis developed by Morgan Worldwide, Inc., which provides results that are extrapolated to the universe of mines affected by the Proposed Rule. These model mines are hypothetical mines developed to be representative of the locations where coal mining occurs, the types of mining operations expected to be seen under baseline conditions, and the production rates at various mines throughout the coal producing regions of the United States. The specific characteristics of the approximately 1,200 coal mines in the United States make a mine by mine analysis impracticable. This approach has been successfully employed in other contexts.

The purpose of assessing the impacts of the Proposed Rule and the alternatives at the model mine level is to approximate how mining operations in each region might change operations or be designed in response to different requirements and elements of each alternative, and to develop metrics that can be used to further calculate the benefits and impacts of the alternatives. This analysis designed and analyzed thirteen "representative" model mining operations, which are categorized by region and size (tons of coal produced annually), as detailed in Exhibit ES-3. The analysis also incorporated designs for five coal refuse facilities associated with underground mining operations.

POTENTIAL IMPACTS TO UNDERGROUND MINING

SMCRA states that in order to receive a permit, an operator must demonstrate that "the proposed operation thereof has been designed to prevent material damage to hydrologic balance outside permit area" (30 U.S.C.§ 510 (b)(3)). However, existing coal mining regulations do not define "material damage to the hydrologic balance outside the permit area." Because of the depth and resource-specific nature of underground mining, Appendix D separately assesses whether the addition of a national definition of "material damage to the hydrologic balance outside the permit area," (MDHB) is likely to impact the recovery of underground mineable coal in the United States.

EXHIBIT ES-3. MODEL MINE DEFINITIONS

REGION	MINE TYPE	ANNUAL PRODUCTION (MILLION TONS)
Appalachian Basin	CAPP[1] Surface - Area	2.3
	CAPP Surface - Contour	0.5
	CAPP Underground (Room and Pillar) [3]	0.3
	NAPP[2] Surface – Contour	0.2
	NAPP Underground (Longwall) [3]	4.6
Colorado Plateau	Surface – Area	3.3
	Underground (Longwall) [3]	3.0
Gulf Coast	Surface – Area	3.3
Illinois Basin[4]	Surface – Area	1.0
	Underground (Room and Pillar) [3]	2.1
	Underground (Longwall) [3]	6.0
Northern Rocky Mountain and Great Plains	Surface – Area	27.2
Northwest	Surface – Area	2.0
Western Interior[4]	Surface – Area	1.0
	Underground (Room and Pillar)	2.1

[1] CAPP = Central Appalachia

[2] NAPP = Northern Appalachia

[3] The analysis also designed coal refuse facilities associated with these underground mining operations.

[4] The model developed for Illinois Basin surface and room and pillar underground mines were also used to evaluate impacts to the Western Interior mining activities.

ENVIRONMENTAL IMPACTS

Our assessment of the Proposed Rule's environmental impacts draws upon the model mine analysis, additional spatial and economic data, and information from published literature to characterize the environmental impacts of the Proposed Rule. These impacts are quantified where possible and extrapolated to the mining region and over time based on production forecasts. Specifically, impacts are quantified according to the following steps:

1. Elements of the Proposed Rule are inventoried and mapped to categories of environmental and health impacts;

2. Information on physical and operational changes at the mine level from the model mine analysis are combined with additional data and information to develop mine-level environmental impact measures expressed per unit of production (where feasible); and

3. Per-unit environmental impacts are aggregated to the mining region and nationally, over the time frame of the analysis, based on production forecasts by region and by mine type.

Ideally, all quantified impacts would be monetized. However, economic values associated with most quantified impacts are highly context-specific. For example, the value of improved water quality is influenced by existing and potential future uses of the resource and will vary spatially. Likewise, monetary values will be influenced by whether the resource supports recreational uses, the nature and extent of species present, and proximity to population centers. Because it is not possible to predict the number and location of specific mining operations over the time frame of the analysis or to properly characterize these resource attributes, assignment of monetary values to the changes expected to result from the Proposed Rule is not possible. Following this approach, we estimate the environmental impacts presented in Exhibit ES-4A through ES-4E. Exhibit ES-4A describes how the Proposed Rule changes environmental conditions, and relates these changes to effects on ecosystem services, defined as the benefits people obtain from ecosystems. Exhibit ES-4B describes the rationale for not monetizing the quantified impacts. Exhibits ES-4C through 4E provide more information on the quantified benefits metrics. As noted above, the majority of the forecast impacts of the Proposed Rule are expected to occur in the Appalachian Basin.

EXHIBIT ES-4A. SUMMARY OF ENVIRONMENTAL IMPACTS OF PROPOSED RULE: 2020-2040

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	DESCRIPTION OF CHANGE	EFFECTS ON ECOSYSTEM SERVICES
Water Quality	Fewer stream miles adversely impacted, improved water quality (e.g., pH, selenium, TDS) within watershed. Potential for beneficial impacts to groundwater quality and quantity	Stream restoration, fill construction and handling requirements, and reforestation requirements	Per year 292 downstream improved stream mile; 29 stream miles restored; 4 stream miles not filled; 1 downstream preserved stream mile	Increased water quality enhances ecosystem, recreational, and some consumptive use services
Biological Resources	Reduced impacts to aquatic riparian and forest communities, including habitat enhancements for threatened and endangered species	Stream restoration, reforestation, and species protection requirements	Water quality benefits stated above; Annual estimates of 2,811 acres of forest improved and 20 acres of forest preserved	Increased quality or quantity of habitat enhances recreational opportunities and aesthetic conditions
Visual Resources	Improved aesthetics	AOC requirements and reforestation requirements	Water quality, forest, and biological resource benefits stated above	Improved aesthetics may improve property values and the quality of recreational opportunities
Air Quality and Greenhouse Gas Emissions	Additional carbon storage capacity of forests, changes in emissions (e.g., NO_X, SO_2, PM, CH_4) from mining activity and transportation activities	Reforestation requirements and fill design changes	Increased reforestation (see Biological resources above) and associated increased carbon storage; Reduced emissions of air pollutants (including greenhouses gases) due to overall reduction in coal mining activity (e.g., methane emissions decrease by approximately 311 million cubic feet (MMcf) per year).	Increased carbon storage and reductions in emissions reduce human health risks and climate change-related risks
Public Health	Reduced exposure to contaminants in drinking water and air	Stream restoration and reforestation requirements	Water quality benefits and biological resource benefits stated above	Reduced probability of adverse health effects, or incurring costs to mitigate those effects
Recreation	Potential for increased recreational opportunities, improved aesthetics	Elements directly affecting water quality and biological resources (e.g., stream restoration) as well as AOC requirements and post-mining land use	Water quality, forest, and biological resource benefits stated above	Increased quality or quantity of recreational fishing, hunting, wildlife viewing, or hiking opportunities
Other	Reduced risk and severity of adverse impacts, including long-term pollution discharges during and after mining	Baseline data collection, monitoring, and material damage definition	Water quality, and air quality resource benefits stated above	Reduced human health risks, improved recreational opportunities, improved aesthetics

The Proposed Rule generates these ecosystem service benefits in two ways. First, implementation of the rule requirements (e.g., reducing stream fill, requiring restoration and enhancement, reforestation and revegetation elements) improves water and habitat quality, as described in Exhibit ES-4A. Improved environmental conditions in turn reduce human health risks from exposure to water or air-borne contaminants. They also improve the aesthetics of the landscape and habitat conditions for native species, enhancing recreational experiences (e.g., fishing, hunting, hiking, wildlife-viewing) and potentially benefitting property values.

Second, ecosystem service benefits result from the overall reduction in coal mining activity (surface and underground) expected to result from the Proposed Rule. The collective burden on coal operators of implementing all of the rule elements increases the cost of coal production, as described in the previous chapters. The increased costs of production due to the Proposed Rule result in a reduction in overall coal production levels. Reduced production accordingly results in a reduction in the negative environmental impacts of coal mining, for example by preserving some stream from coal mining effects. One category of ecosystem service benefits described in Exhibit ES-4A that is attributed specifically to the reduction in overall levels of coal production (as opposed to the implementation of a given rule requirement) is air quality and greenhouse gas improvements (e.g., reduced emissions).

Given available data, we are unable to reliably monetize the benefits of the Proposed Rule. For four categories we are, however, able to quantify the benefits in terms of biophysical changes (i.e., units of the resource, such as stream miles or acres of forest). Exhibit ES-4B describes the categories of quantified benefits and the reason these quantified changes are not monetized. Importantly, the quantified metrics described in Exhibit ES-4B do not present a complete picture of the benefits expected to water quality, biological resources, and air quality and greenhouse gases. In addition to these quantifiable metrics, additional metrics of water quality benefits (including reduced contaminant levels, improved conditions to support biodiversity), biological resources (including increased quality or quantity of habitat for endangered species), and air quality benefits (including increased carbon sequestration potential and reduced emissions of other contaminants) are described qualitatively in this chapter.

EXHIBIT ES-4B. QUANTIFIED BENEFIT CATEGORIES

CATEGORY	QUANTIFIED BENEFITS METRICS	RATIONALE FOR NOT MONETIZING THE QUANTIFIED BENEFIT
Water Quality	• **Stream miles not filled:** Streams not filled due to the SPR. • **Stream miles restored**: Mined through streams that are restored due the SPR. • **Downstream stream miles preserved**: Streams that do not experience water quality impacts due to reduced mining activity. • **Downstream water quality improvements (miles)**: Streams that experience water quality improvements with the SPR.	While the analysis is able to estimate the linear extent of stream miles expected to be improved by the rule, the specific improvement in particular water quality parameters, such as pH or selenium levels, is uncertain. Information on both the baseline contaminant levels and the expected change in these water quality parameters at given mine sites would be required to monetize the improvement. To accommodate these uncertainties, information on the geographic scope of the stream improvements are presented alongside a qualitative discussion of the environmental changes and associated ecosystem service benefits (i.e., public health and recreational experiences) expected.
Biological Resources	• **Improved Acres:** Land that will benefit from improved forest land cover either because: a) it would have been restored to grassland, pastureland or an alternative PMLU in the baseline; or b) it would have been reforested under the baseline but the SPR prescribes better practices to ensure healthier forest post-mining (i.e., Forestry Reclamation Approach (FRA)). • **Preserved Acres:** Forest area that is left uncut due to changes in coal mining activity.	Ecosystem services associated with additional forest cover include reduced risk of climate change-related damages (due to increased carbon sequestration potential of the landscape), increased quality and quantity of endangered species and other species habitat, and aesthetic improvements (these improvements may also improve conditions for recreational activities and increasing property values). While increased forest and vegetative land cover resulting from the rule may increase the carbon sequestration potential of the landscape, other effects of the rule may counteract these by increasing carbon emissions. For example, increased hours spent hauling materials during reclamation may increase transportation emissions. Limitations on monetizing the carbon sequestration benefits of forests are discussed in Section 7.3. With respect to potential property value and recreational benefits, monetization of these benefits would require information on the specific locations of the acres likely to be improved due to the rule, as well as information on the baseline values of residential properties and volume and value of recreational activities.

CATEGORY	QUANTIFIED BENEFITS METRICS	RATIONALE FOR NOT MONETIZING THE QUANTIFIED BENEFIT
Air Quality and Greenhouse Gas Emissions	• **Reduced methane (CH_4) emissions:** Reduced methane associated with overall reductions in coal mining activity levels (note: not a net effect of the SPR on emissions levels).	Estimates of changes to methane provide some perspective on how reductions in coal production due to the Proposed Rule may affect mining-related emissions. However, this is not a complete picture of the effect of the rule on emissions. As discussed in Section 7.3, the quantified reduction in methane emissions is not a net effect as it does not account for potential counteracting effects of the rule due, for example, to increased haulage or increased production of substitute sources of energy production. Accordingly, while this estimate provides some context, namely describing that effects of the rule on emissions are on the order of a fraction of a percent of emissions from coal mining, presenting this effect as a monetized benefit of the rule may be misleading.

For other categories of benefits, data limitations do not support quantifying the improvements, even in biophysical terms. We accordingly describe the following benefits qualitatively in Chapter 7.

- **Public Health:** Existing studies find negative health effects of mining-related contaminants in water and air in coal mining communities. Although more research on human exposure and human health impacts is still needed to fully understand causal relationships, we believe it is reasonable to assume the Proposed Rule will yield public health-related benefits through expected improvements in air and water quality.
- **Visual Resources:** Improved aesthetic conditions of the landscape post-mining has the potential to enhance recreational experiences (as noted above), as well as regional property values.
- **Recreational Benefits:** Potential benefits to fishing, hiking, wildlife-viewing, hunting, etc. due to improved quality of streams and increases forest land cover benefitting regional wildlife populations. In addition, aesthetic improvements due to reforestation and PMLU requirements may enhance recreational experiences.

EXHIBIT ES-4C. AVERAGE ANNUAL STREAM MILE IMPACTS UNDER THE PROPOSED RULE BY REGION: 2020-2040

COAL REGION	DOWNSTREAM IMPROVED[1]	DOWNSTREAM PRESERVED[2]	NOT FILLED[3]	RESTORED[4]
Appalachian Basin	174	1	4	1
Colorado Plateau	6	0	0	4
Gulf Coast	36	0	0	7
Illinois Basin	51	0	0	11
Northern Rocky Mountains and Great Plains	22	0	0	6
Northwest	2	0	0	0
Western Interior	2	0	0	0
Total	**292**	**1**	**4**	**29**

Notes: See section 7.3 for more detail on water quality impacts.
[1] Stream miles that experience water quality improvements with the Proposed Rule.
[2] Stream miles that do not experience water quality impacts due to reduced mining activity.
[3] Streams not filled due to the Proposed Rule.
[4] Mined through streams that are restored due to the Proposed Rule.

EXHIBIT ES-4D. AVERAGE ANNUAL FOREST AREA IMPACTS UNDER THE PROPOSED RULE BY REGION: 2020-2040

COAL REGION	IMPROVED ACRES[1]	PRESERVED ACRES[2]
Appalachian Basin	1,346	19
Colorado Plateau	431	0
Gulf Coast	483	0
Illinois Basin	377	1
Northern Rocky Mountains and Great Plains	105	0
Northwest	1	0
Western Interior	67	0
Total	**2,811**	**20**

Notes:
[1] Land that will benefit from improved forest land cover under the Proposed Rule because it would otherwise have been put in grassland, pastureland or an alternative postmining land use, or would have been reforested under the baseline. The Alternative prescribes better practices to ensure healthier forest postmining for these acres.
[2] Forest areas that is left uncut due to changes in coal mining activity.

EXHIBIT ES-4E. AVERAGE ANNUAL CHANGES IN METHANE EMISSIONS UNDER THE PROPOSED RULE: 2020-2040 (MIL. CF)

COAL REGION	SURFACE MINES	UNDERGROUND MINES	NET CHANGE
Appalachian Basin	(18)	(191)	(208)
Colorado Plateau	0	1	1
Gulf Coast	0	0	0
Illinois Basin	(4)	(80)	(84)
Northern Rocky Mountains & Great Plains	(18)	(1)	(19)
Northwest	0	0	0
Western Interior	0	0	0
TOTAL	**(39)**	**(271)**	**(311)**

Notes: Estimates of changes to methane provide some perspective on how reductions in coal production due to the Proposed Rule may affect mining-related emissions. However, this is not a complete picture of the effect of the rule on emissions. As discussed in Section 7.3, the quantified reduction in methane emissions is not a net effect as it does not account for potential counteracting effects of the rule due, for example, to increased haulage or increased production of substitute sources of energy production. Accordingly, while this estimate provides some context, namely describing that effects of the rule on emissions are on the order of a fraction of a percent of emissions from coal mining, presenting this effect as a monetized benefit of the rule may be misleading.

INCREASED COSTS OF MINING OPERATIONS

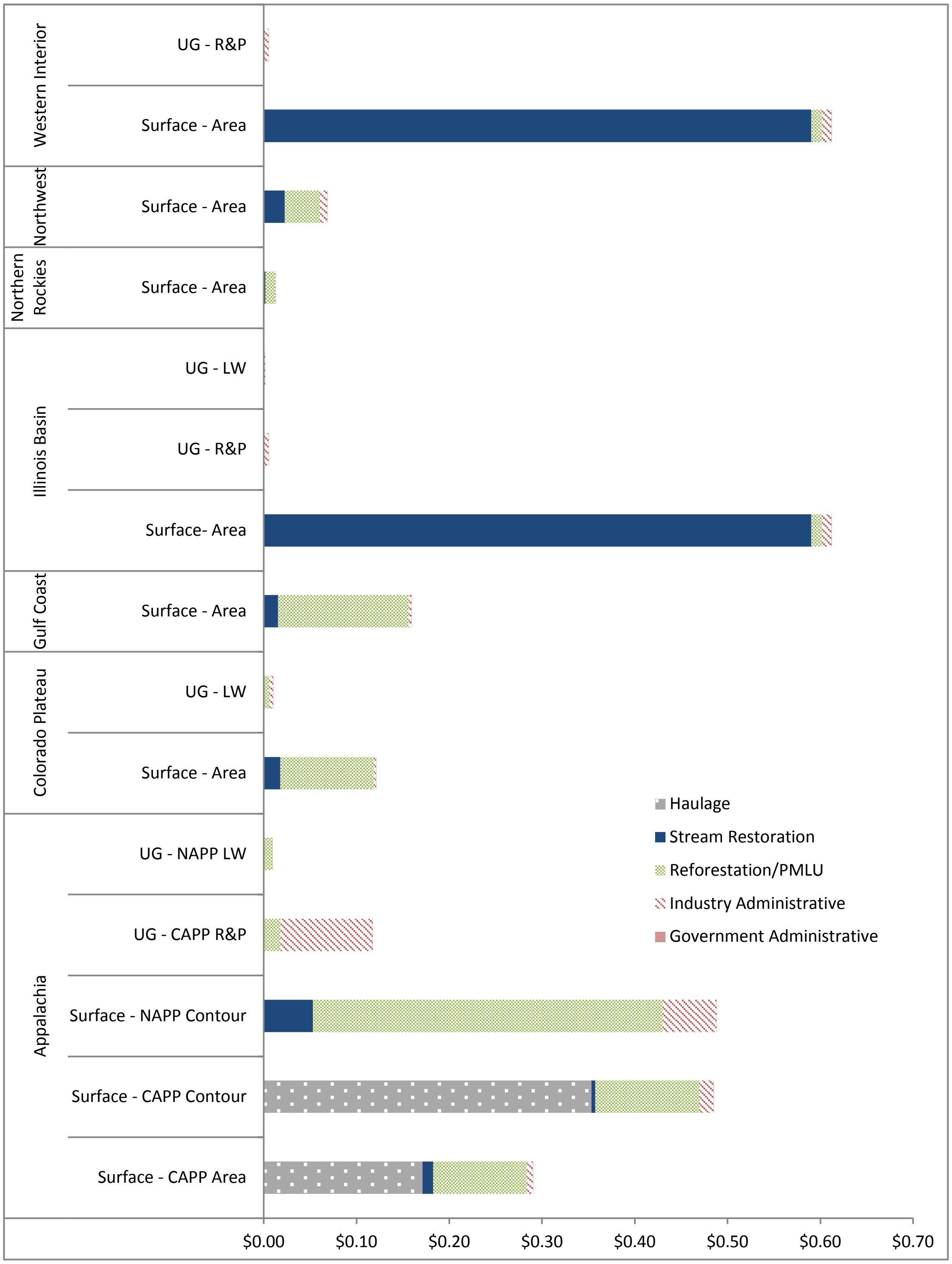
To develop an estimate of the compliance costs of the Proposed Rule, we estimate the expected increase in operational and administrative costs for each of the 13 model mines over the 2020 to 2040 time horizon of our analysis. We then convert these costs to costs per ton of coal produced. The details of this analysis are described in Chapter 4 and Appendix B. Exhibit ES-5 displays the increased compliance costs by cost category for each region and model mine. As shown:

- Central Appalachian Basin surface area mining incurs costs primarily related to increased haulage costs, with some costs related to reforestation, stream restoration, and industry administrative costs;
- Central Appalachian Basin surface contour mines are forecast to incur costs primarily related to haulage as well as some reforestation stream restoration, and industry administrative costs;
- Illinois Basin and Western Interior surface mines are forecast to see cost increases primarily related to stream restoration costs. We note that while costs are highest on the basis of costs per ton in these mines, the overall production of this mine type at the national scale is relatively modest;
- Northern Rocky Mountain, Colorado Plateau, and Gulf Coast surface mining operations are forecast to incur costs that primarily stem from increased reforestation costs as well as some stream restoration costs;

- Northwest surface mining operations are forecast to see costs primarily related to reforestation and stream restoration as well as some industry administrative requirements;
- Northern Appalachian Basin surface contour mines are forecast to incur costs primarily related to reforestation as well as some stream restoration and industry administrative costs;
- Compliance costs anticipated for underground mining activities in all regions are related to increased reforestation costs and the administrative requirements of the rule. Central Appalachian Basin underground room and pillar mines are forecast to see costs primarily related to industry administrative costs as well as some reforestation costs. Northern Appalachian Basin and Colorado Plateau underground longwall mines are forecast to incur costs primarily related to reforestation, with a smaller percentage coming from administrative requirements. Illinois Basin and Western Interior underground mining operations are forecast to incur costs entirely from additional administrative costs.

For each model mine site, the engineers considered the topography, geology, hydrology, equipment needs, strip ratios, and other site-specific conditions to determine the most appropriate and likely industry response to the new regulations. The engineers used their expertise in applying industry standards and best practices, including consideration of site stability and safety considerations, to select the most appropriate actions and associated costs for each model mine. Recognizing that assumptions in the engineering analysis are important to the overall results of the regulatory impact analysis, a number of sensitivity analyses were conducted related to specific assumptions. These sensitivity analyses are described in Appendix B, Part 6. Tested assumptions included assumptions related to hourly equipment costs for haulage costs, spoil handling percentage of overburden in haulage costs, per acre costs of reforestation in riparian zones, production levels and stripping ratios. OSM requests public comment on these assumptions.

EXHIBIT ES-5. INCREASED COMPLIANCE COSTS PER TON



Note: The model developed for Illinois Basin surface and room and pillar underground mines were also used to evaluate impacts to the Western Interior mining activities.

INCREASED COSTS TO UNDERGROUND MINING OPERATIONS

Appendix D of this RIA presents an analysis of the potential effects of the addition of a definition of MDHB on the recovery of underground mineable coal. Factors affecting possible stream loss from subsidence (MDHB) are varied and include mine height, mine configuration, extraction rate, overburden thickness, lithology, drainage area, previous mining, topography, and local and regional aquifer characteristics. Combined, these factors present a challenge for the evaluation of potential MDHB impacts of mining activities. The complexity of this evaluation requires substantial data for modeling local conditions and determining the likelihood and extent of subsidence induced impacts. To assess the potential impacts of a national MDHB definition, Appendix D examines longwall coal resources on a regional level.

Longwall production from the Northern Appalachia, Illinois Basin, and Colorado Plateau regions together was about 150 million tons in 2012, representing about 77 percent of the volume of coal produced in the United States by this mining method. With almost 82 million tons mined, Northern Appalachia was the largest producer of longwall coal in the United States in 2012. The principal longwall-minable coal seam in Northern Appalachia is the Pittsburgh Seam. For the Pittsburgh Seam, overburden depths in Northern Appalachia vary from less than 200 feet in Ohio to greater than 1000 feet in northern West Virginia. Due to the variation in overburden depths across the Pittsburgh coal bed and its vast size, a geospatial analysis was initiated to model the resources that lie above and below the 400-foot threshold overburden depth.

Based upon coal seam height data and using a minimum 4-foot seam height for longwall mineable resources, about 10.5 billion tons of total longwall mineable resource was estimated in the Pittsburgh seam.[1] Of this resource, approximately 8.7 billion tons, or 83 percent, are located where overburden thickness is greater than 400 feet and thus is assumed to be mineable by longwall methods without MDHB being a major concern. In general, where the Pittsburgh seam has less than 400 feet of overburden, it could still be mineable by room and pillar methods and, in some cases, by longwall methods, depending on the results of a site-specific analysis.

In Southeastern Ohio, the overburden above the Pittsburgh seam thins and can be less than 200 feet in thickness. However, this same overburden appears to contain significant claystone and shale strata. Where overburden is dominated by claystone and shale, which typically have relatively high plasticity, longwall mines can potentially operate at less than the overburden threshold depth without causing permanent stream loss.

For the Illinois Basin, all current mines are operating deeper than the 200-foot threshold depth and future longwall mines are not expected to operate at shallower overburden depths. With groundwater levels unaffected or readily recovered, permanent stream loss (MDHB) does not appear to be a factor in this region. For the Colorado Plateau, most current mines are operating deeper than the 500-foot threshold overburden depth and future mines are anticipated to mine at similar or greater depths. Therefore, permanent stream loss due to longwall mining does not appear to be a prominent issue in this region.

[1] This calculation total does not assess whether this resource is economically mineable or would otherwise be unmineable due to legal, environmental, social, or other restrictions.

Overall, the analysis finds that significant underground mineable reserves exist in areas where MDHB would not be expected to occur. As such, a national definition of MDHB would still allow substantial coal reserves to be recovered using the longwall mining method.

COAL MARKET EFFECTS

The impact of the Proposed Rule is based upon the forecast markets for U.S. coal with and without the Rule. Electricity demand growth, installed coal-fired generating capacity, the relative prices of alternative fuel sources, coal demand from the domestic metallurgical and industrial markets, net U.S. exports of coal, and existing and proposed environmental rules all affect the future supply and demand for U.S. coals, which in turn affects coal pricing. The price of U.S. coals drives domestic coal production.

To assess these and related energy market impacts in the context of the Proposed Rule and the alternatives, we employ a suite of energy market models designed and maintained by Energy Ventures Analysis, Inc. (EVA). These models include significant detail with respect to both coal production and consumption. These models simulate coal production by mine type and mine region, accounting for regional differences in reserve depletion, coal mining technology, permit restrictions (e.g., the impact of valley fill permit limits on Appalachian surface mining), mine safety regulations, labor availability and costs, and the availability and cost of Federal coal leases. Similarly, the models' treatment of coal demand considers a range of factors that influence demand, including (1) changes in electricity demand and the associated implications for power plants' demand for coal, (2) fuel substitution associated with changes in the price of coal relative to natural gas, and (3) environmental regulations that affect power plant demand for coal. The coal demand sectors incorporated into the EVA models include:

- Electric power;
- Domestic metallurgical coal consumers (coke ovens and pulverized coal injection);
- Industrial consumers (industrial boilers, cement kilns, etc.);
- Commercial consumers (universities, public buildings, etc.);
- Export metallurgical consumers; and
- Export steam coal consumers.

Employing the EVA models and results, we estimate the rule's impact on coal production by region and mine type, coal demand by major consuming sector, and coal prices by region.

Our primary baseline forecast of coal production, absent the Proposed Rule, shows a decrease in national coal production of 162 million tons between 2020 and 2040, or a 15 percent decrease during the study period for our analysis. To capture uncertainty in the forecasts, we also developed alternative "low coal demand" and "high coal demand" baseline scenarios. The low and high demand baselines include alternative assumptions for a limited number of variables that have a significant influence on coal demand. Thus, the low- and high-end alternatives developed for this analysis represent feasible, but less likely, baseline scenarios.

The Proposed Rule is anticipated to affect coal production and consumption patterns across the U.S. over and above baseline conditions. With respect to production, the operational restrictions engendered by the various regulatory options will increase the cost of producing coal, which may lead to an aggregate reduction in coal production across the U.S. Such changes in coal production, however, will not be uniform across the U.S., as the Proposed Rule will differentially affect mine production costs by region and mine type. Similarly, the changes in coal production costs associated with the Proposed Rule vary by region due to differences in geology, baseline mining practices, and other factors. This will lead to changes in the distribution of production across mining regions. The increase in coal prices associated with higher production costs may also lead to a reduction in coal consumption. As prices rise, power plants, industrial facilities, and other coal consumers may substitute other sources of energy (e.g., natural gas) for coal.

Using EVA's market assumptions that relate to electric power demand, environmental regulations, capacity retirements and additions, non-utility domestic coal consumption, exports, and coal pricing methodology, EVA developed a baseline demand forecast from which to compare each SPR alternative. Employing these models, we estimate the Proposed Rule's impact on coal production by mine type and region. Exhibits ES-6A through 6C show the annual change in coal production under the Proposed Rule from 2020 through 2040. Annual percentage change in coal production ranges from a decrease of 0.4 percent in 2022 to a decrease of 0.02 percent in 2039. Annual change in million tons of coal produced ranges from a decrease of 4.6 million tons in 2022 to a decrease of 0.2 million tons in 2039 with an average annual decrease of 1.9 million tons. As shown in these exhibits, we forecast a reduction in overall coal production over this period relative to the baseline. This reduction largely reflects substitution of natural gas for coal among power plants across the U.S. due to the increase in coal prices expected under the Proposed Rule. The magnitude of these forecast changes varies by region. As shown in Exhibit ES-7, changes in coal production are expected to occur primarily in the Appalachia, Illinois Basin, and Northern Rocky Mountain regions under the Proposed Rule. In the Appalachian Basin, coal production is expected to decrease by 17.9 million tons over the study period. Underground mining is expected to account for 12.3 million tons of the decrease and surface mining for 5.6 million tons of the decrease over the study period. In the Illinois Basin a decrease of 6.4 million tons of coal is expected, with changes in underground mining accounting for 5.2 million tons of the decrease and surface mining for 1.2 million tons of the decrease over the study period. In the Northern Rocky Mountain region, a decrease of 14.7 million tons of coal production is expected over the study period almost entirely from changes in surface mining.

The suite of models that we employ to assess changes in coal production and pricing under the Proposed Rule include a rich representation of coal market dynamics. Nevertheless, as a stylized representation of these markets, the models may not capture variables that are difficult to observe and/or measure (e.g., coal production costs by mine). In addition, the model relies on several exogenous forecasts, any of which may affect model results (e.g., GDP growth, the strength of the U.S. dollar, etc.). The impact of these uncertainties on the results of our analysis is unknown. To minimize uncertainty, the EVA market models rely on disaggregated data (e.g., for individual power plants) where possible to capture the likely response of regulated entities.

EXHIBIT ES-6A. ANNUAL PERCENT CHANGE IN COAL PRODUCTION UNDER THE PROPOSED RULE RELATIVE TO THE BASELINE FORECAST, 2020-2040

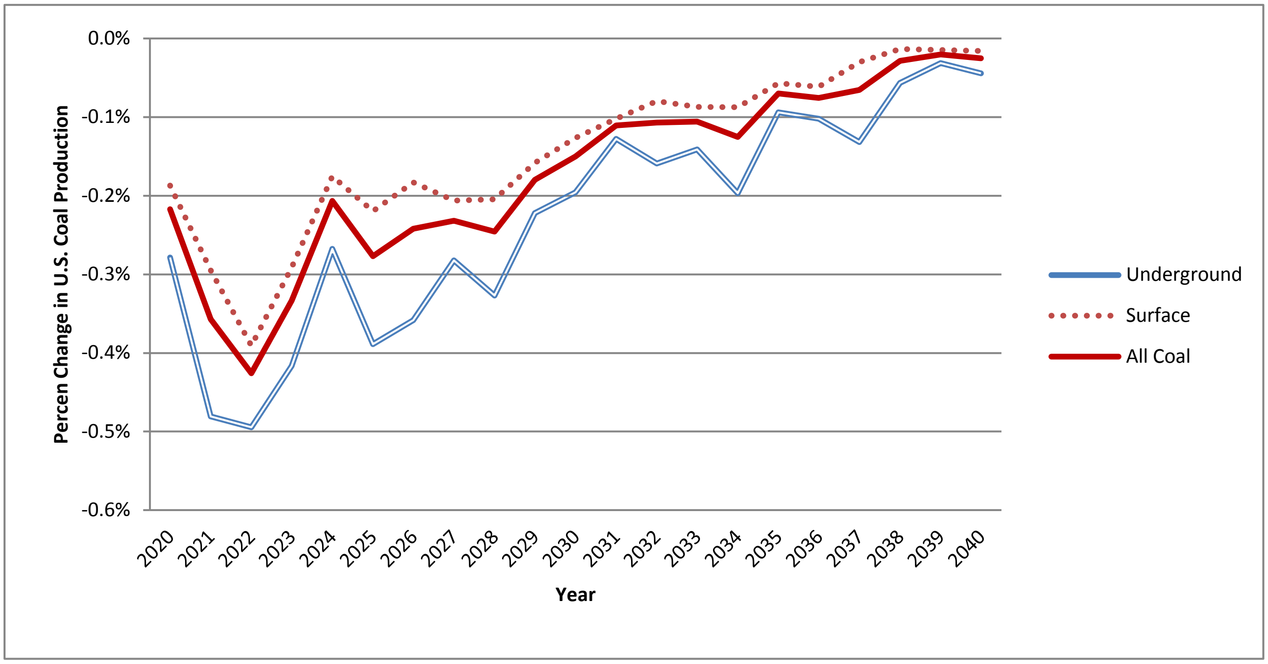
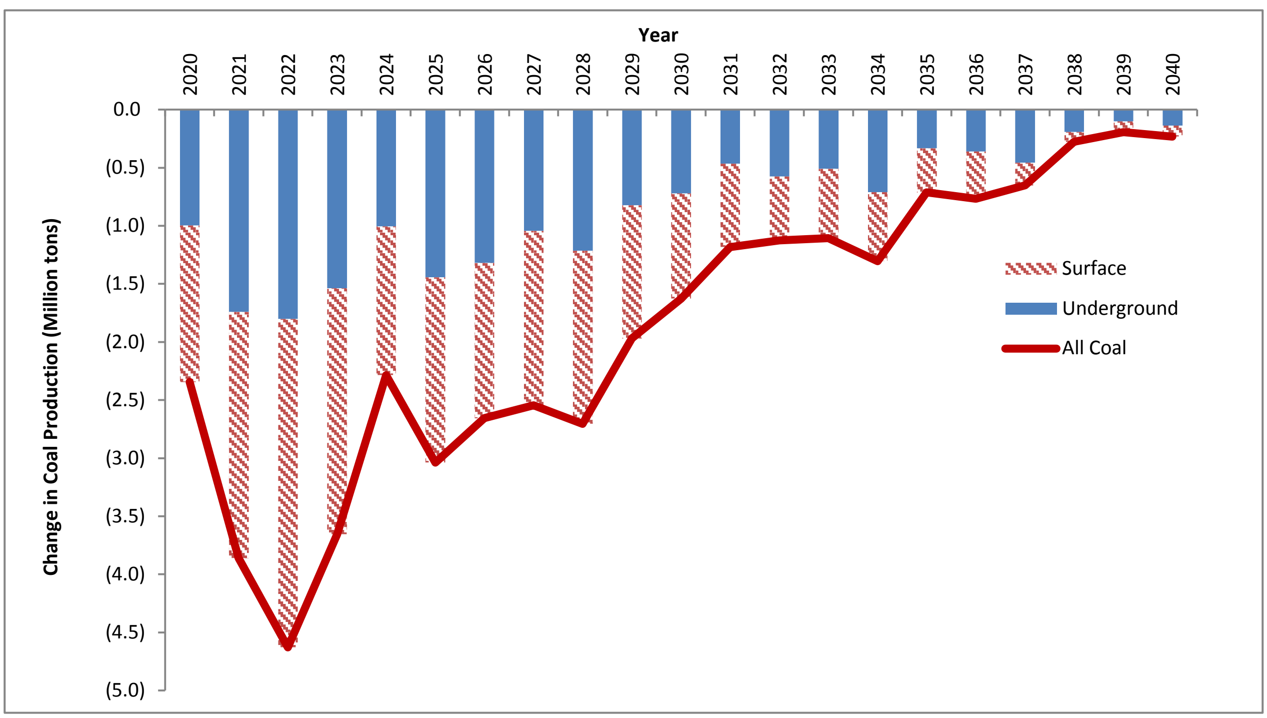
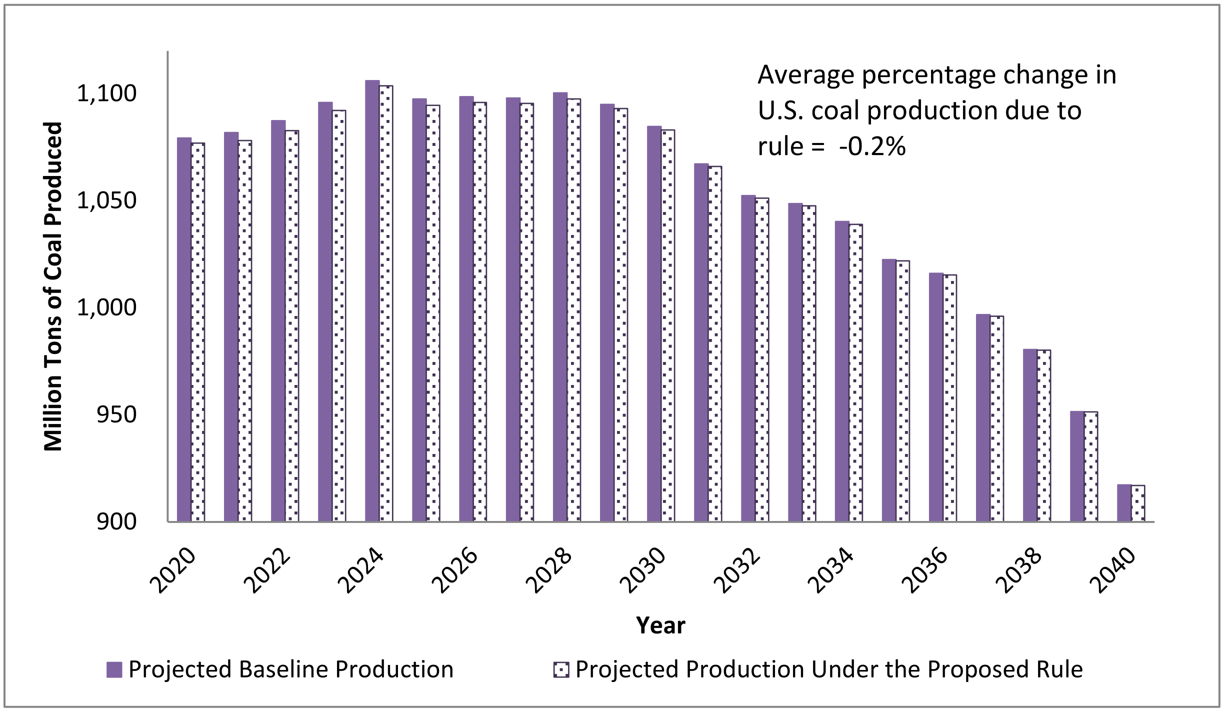


EXHIBIT ES-6B. ANNUAL CHANGE IN COAL PRODUCTION UNDER THE PROPOSED RULE RELATIVE TO THE BASELINE FORECAST (MILLIONS OF TONS)



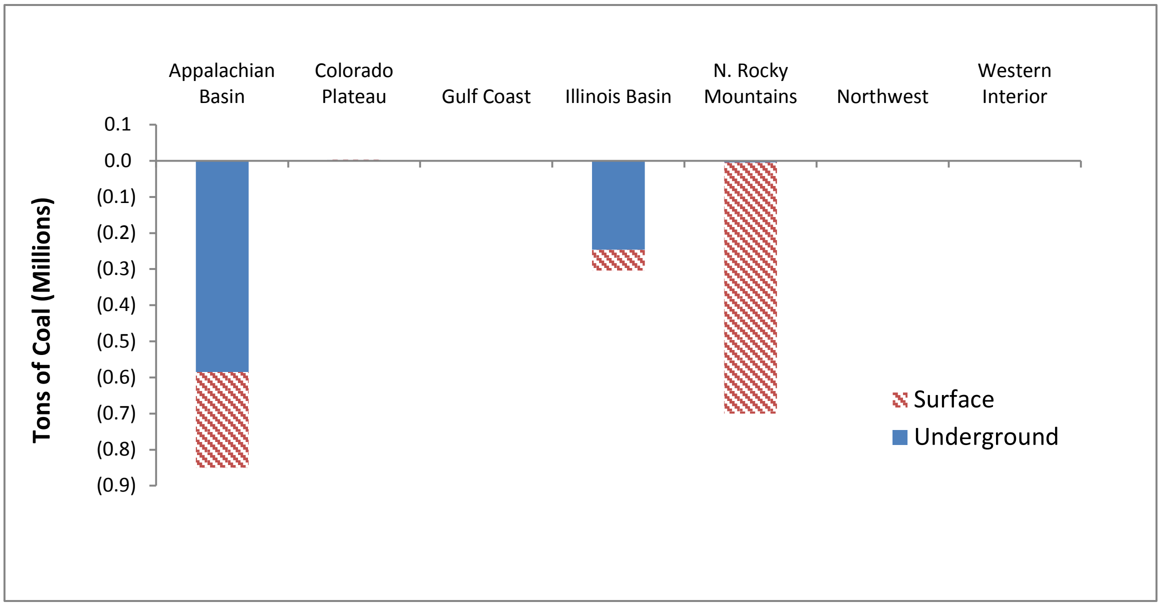
Note: The impacts of the SPR on coal production are calculated based on estimated increased costs of coal production per ton of coal produced (compliance costs). Thus, in general, as U.S. coal production declines over the time period for the analysis, the costs of compliance with the Proposed Rule also decline.

EXHIBIT ES-6C. ANNUAL COAL PRODUCTION UNDER BASELINE CONDITIONS AND THE PROPOSED RULE, 2020-2040 (MILLIONS OF TONS)



Note: Baseline forecast coal production, absent the Proposed Rule, shows a decrease in national coal production of 162 million tons between 2020 and 2040, representing a 15 percent decrease during the study period for our analysis. The annual reduction in tons of coal produced due to the Proposed Rule ranges from a decrease of 4.6 million tons in 2022 to a decrease of 0.2 million tons in 2039, with an average annual decrease of 1.9 million tons compared to forecast baseline production. While the specific assumptions and results of the model can be debated, the direction of the resulting change, i.e., the impact of the rule is an increase in cost that results in decreased coal production, is robust.

EXHIBIT ES-7. AVERAGE ANNUAL COAL PRODUCTION CHANGE FORECAST BY REGION AND MINE TYPE FROM 2020-2040 UNDER THE PROPOSED RULE, 2020-2040 (MILLIONS OF TONS)



Notes: The projected change in each region represents less than 0.5 percent of baseline study period regional production. The projected change in Appalachia represents 0.4 percent of baseline study period regional production (annual average of 236 million tons). The projected change in Illinois Basin represents 0.2 percent of baseline study period regional production (annual average of 170 million tons). The projected change in the Northern Rocky Mountains and Great Plains represents 0.1 percent of baseline study period regional production (annual average of 533 million tons). For context, total coal production in 2012 was 1,106 million tons (MSHA, 2012).

ASSESSMENT OF COMPLIANCE COSTS

To develop an estimate of the total compliance costs of the Proposed Rule, we estimate the expected increase in operational and administrative costs for each of the 13 model mines over the 2020 to 2040 time horizon of our analysis. We then convert these costs to costs per ton of coal produced. To estimate the compliance costs of the rule for each year in the study period, we apply these estimates of compliance costs per ton to the corresponding forecast production level. The operational costs of the Proposed Rule that we capture through this approach include: (1) haulage costs, (2) stream restoration costs, (3) stream enhancement costs, and (4) reforestation and returning land to its pre-mining land use. The administrative costs of the rule reflect a range of activities necessary for implementation of the rule, for both mine operators and regulatory authorities.

Exhibit ES-8 summarizes the estimated compliance costs for the Proposed Rule. For context, $52 million annualized represents approximately 0.1 percent of total industry annual revenues. Central Appalachian coal prices under baseline conditions are expected to be on the order of $70/ton during the forecast period. The added compliance cost associated with the Proposed Rule for surface mines in Appalachia is on the order of $0.43/ton, or 0.6 percent of baseline coal prices.

Nearly 46 percent (or $24 million) of the expected compliance costs of the Proposed Rule (or $52 million) reflect new regulatory requirements on coal mining operations in Appalachia. Of these costs ($24 million), approximately 72 percent (or $17 million) are costs attributed from surface mining operations in Appalachia (or 33 percent of the total cost of the rule). The most significant costs are associated with fill construction and material handling requirements; these requirements generate increased haulage costs that comprise 52 percent of all added operational costs to surface mines in Appalachia. Reforestation and stream restoration also comprise a significant component of forecast costs at Appalachian surface mines.

EXHIBIT ES-8. ANNUALIZED INDUSTRY AND STATE REGULATORY AUTHORITY COMPLIANCE COSTS UNDER THE PROPOSED RULE, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	$17,000,000	$6,700,000	$24,000,000
Colorado Plateau	$2,500,000	$200,000	$2,700,000
Gulf Coast	$6,200,000	N/A	$6,200,000
Illinois Basin	$14,000,000	$270,000	$14,000,000
Northern Rocky Mountains and Great Plains	$4,800,000	N/A	$4,800,000
Northwest	$98,000	N/A	$98,000
Western Interior	$550,000	$530	$550,000
Total	**$45,000,000**	**$7,100,000**	**$52,000,000**
Note: Estimates may not sum to the totals presented due to rounding.			

ASSESSMENT OF MARKET WELFARE LOSSES

Compliance cost estimates such as those presented in Exhibit ES-8 provide an accounting measure of impacts rather than an economic measure. The former reflects expenditures associated with compliance activities, whereas the latter reflects foregone benefits to both consumers and producers affected by regulatory change. These "welfare" losses are typically measured as changes in producer and consumer surplus.[2] In a given market, producer surplus is the difference between the market price of a good and the marginal cost of production, and consumer surplus is the difference between what consumers are willing to pay for the good and the market price.

As noted above, the Proposed Rule is expected to affect U.S. markets for coal, by increasing the cost of coal production. This is expected to lead to both producer and consumer surplus changes. The net change in market welfare expected to result from this rule is estimated to be $34 million, annualized. This value is primarily associated with an increase in the cost of coal production combined with cost-savings from reduced transportation costs as utilities are expected to shift to nearer sources of coal under the

[2] The discipline of welfare economics focuses on optimizing an allocation of resources by considering the overall effect on a population's well-being. The "welfare impacts" of a rule are accordingly a measure of the overall effect of the rule on well-being of society (i.e., social welfare) or within a given market (e.g., coal market welfare effects).

Proposed Rule. There is an additional cost of approximately $46,000, annualized, from costs to government agencies associated with administering the rule. Note that this measure of the economic impact of the Proposed Rule is not additive with the compliance costs reported above. These are distinct measures of the expected impact of the Proposed Rule.

ASSESSMENT OF EMPLOYMENT IMPACTS

Forecast shifts in the geographic distribution of coal production, the manner in which coal is produced (e.g., surface versus underground), and the total quantity of coal produced, are expected to lead to changes in regional coal industry employment, even absent the Proposed Rule. For context, EIA estimates that 2012 coal industry employment was approximately 90,000 employees. As shown in Exhibit ES-9D, coal industry employment is projected to decrease by over 15,000 FTEs under baseline conditions, i.e., due to factors unrelated to the Proposed Rule, during the study period for the analysis.[3]

Compliance costs of the Proposed Rule are anticipated to result in changes to regional coal industry employment that will be added to and combined with ongoing trends. The relationship between environmental regulation and employment is a subject being debated within the academic literature. As supported by economic theory, environmental regulation can increase production costs, which raises prices, reduces demand, and ultimately puts downward pressure on employment. However, compliance with environmental regulation also typically introduces additional labor requirements, which may mitigate that effect.

We estimate the direct employment demand changes attributable to the Proposed Rule due to anticipated changes in future coal production relative to the baseline forecast. This effect is measured in full time equivalents (FTEs i.e., one full time worker employed for one year). Since the Proposed Rule is expected to reduce the volume of coal produced, we forecast a reduction in employment demand due to this factor (production-related employment effects).

We also estimate some change in economic activity attributable to the cost of industry compliance with the rule. These direct industry compliance costs are detailed in Chapter 4 of this analysis. These activities are expected to increase demand for labor as a result of the rule. Specifically, some increases in employment demand due to work requirements imposed on mining operations by the Proposed Rule could occur (compliance-related employment effects). These additional work requirements include performing inspections, conducting biological assessments, and other tasks that require employment of highly trained professionals (e.g., engineers and biologists) as part of compliance with some elements of the Proposed Rule. Other increased work requirements associated with elements contained in the Proposed Rule are expected to require similar skills as currently utilized by the industry (e.g., bulldozer operations). In general, while some of the increased employment demand may utilize existing mining labor skills (e.g., requirements that require additional earth moving), other employment demand from the Proposed Rule may require other types of labor (e.g., biological monitoring, lab testing,

[3] U.S. EIA. 2013a. Annual Coal Report 2012. U.S. Department of Energy. Table 18: Average Number of Employees by State and Mine Type, 2012 and 2011. Accessed from: http://www.eia.gov/coal/annual/archive/05842012.pdf

paperwork). That is, some additional jobs created by the Proposed Rule may differ in skill requirements from the production-oriented jobs that would be reduced due to decreased coal production.

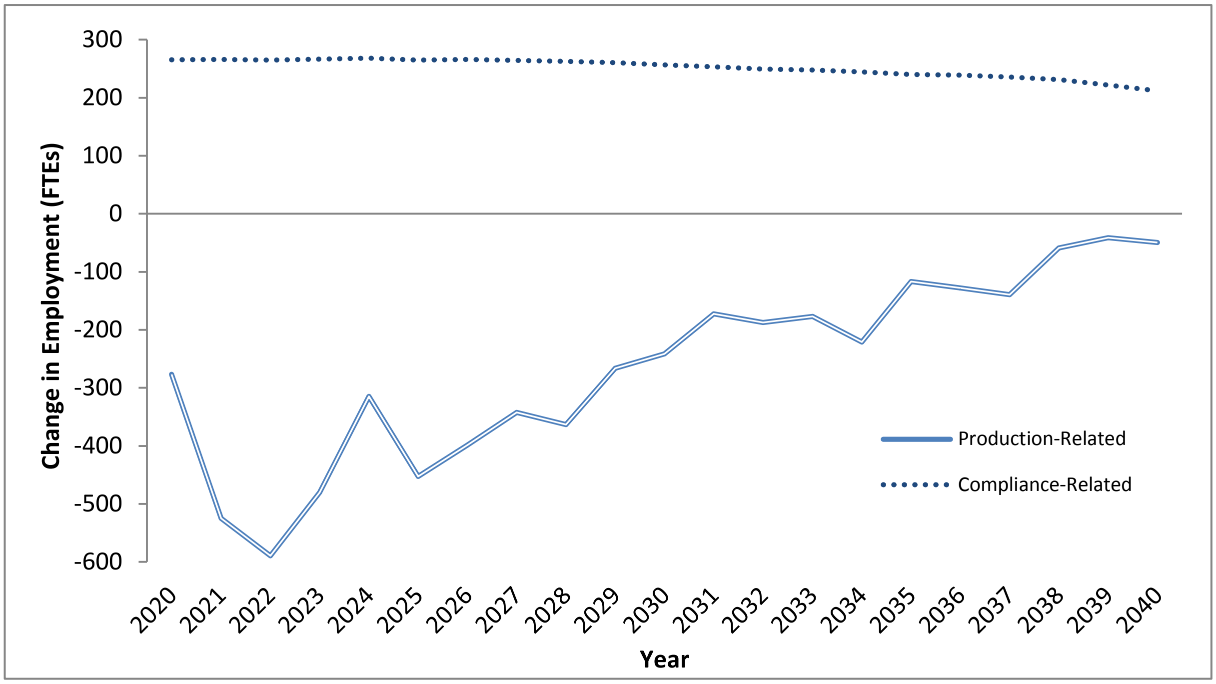
As shown in Exhibits ES-9B through 9D, the forecast national change in employment demand (i.e., number of FTEs or jobs per year) expected to result from the Proposed Rule varies from year-to-year, given changes in forecast industry conditions. As shown in Exhibit ES-9A, production-related reductions in annual employment demand are anticipated to vary from 41 to 590 jobs below baseline projections, while compliance-related annual employment demand increases are anticipated to vary from 210 to 270 jobs above baseline projections. The impacts of the rule are expected to vary regionally, related both directly to rule effects and indirectly to industry responses to the rule. Year to year variation in rule effects are a function of the model of overall coal demand. As shown, the overall scale of impacts is small relative to the size of the coal industry.

EXHIBIT ES-9A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER THE PROPOSED RULE, FTES (2020-2040)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(65)	(140)	(210)	120
	Range in any year:[2]	(140) – (15)	(310) - (24)	(450) - (41)	97 – 120
Colorado Plateau	Average over 21 years:	0	0	0	14
	Range in any year:	0 - 0	0 - 1	0 - 1	12 – 15
Gulf Coast	Average over 21 years:	0	0	0	30
	Range in any year:	(3) - 2	0 - 0	(3) – 2	30 – 31
Illinois Basin	Average over 21 years:	(6)	(27)	(33)	66
	Range in any year:	(19) - 0	(73) - 0	(91) - 0	52 – 76
Northern Rocky Mountains and Great Plains	Average over 21 years:	(22)	0	(22)	21
	Range in any year:	(66) – 0	0 –0	(66) – 0	19 – 22
Northwest	Average over 21 years:	0	0	0	1
	Range in any year:	0 - 0	0 – 0	0 – 0	1 – 1
Western Interior	Average over 21 years:	0	0	0	3
	Range in any year:	0 - 0	0 – 0	0 – 0	3 – 3
U.S. TOTAL	**Average over 21 years:**	**(93)**	**(170)**	**(260)**	**250**
	Range in any year:	**(220) - (17)**	**(370) - (24)**	**(590) - (41)**	**210 - 270**

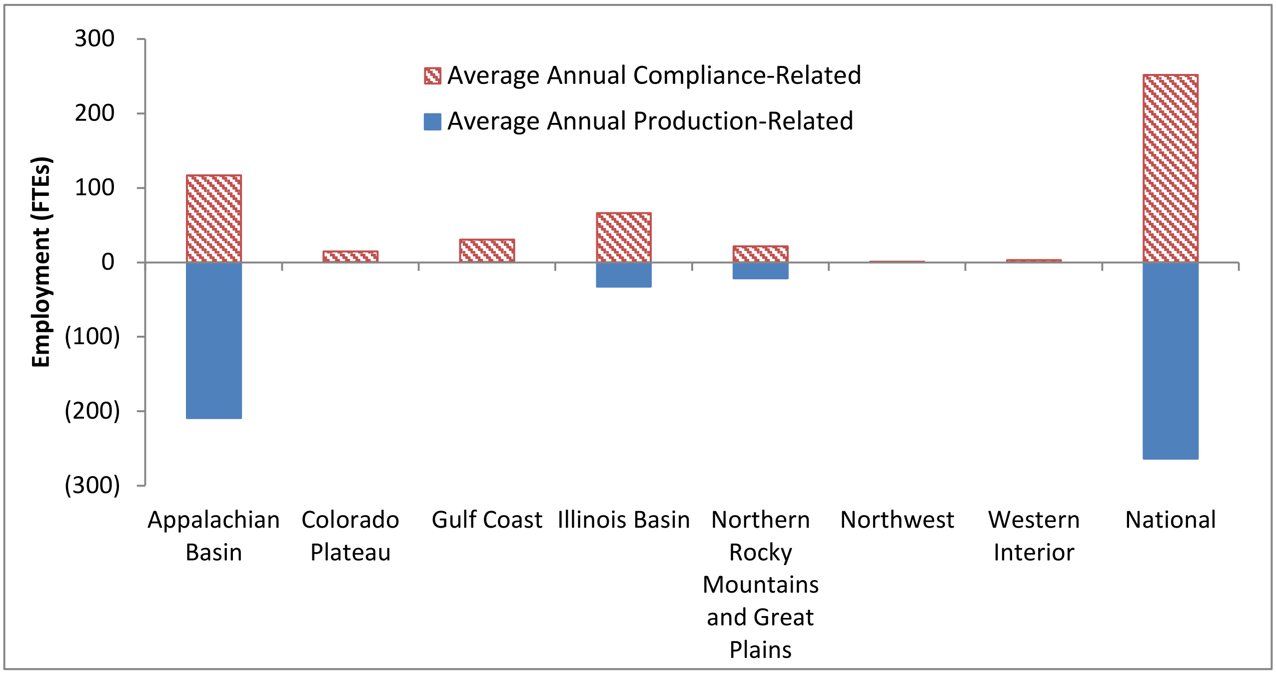
1 "Average over 21 years" is the average annual effect of the Proposed Rule over the study period for the analysis on employment (2020-2040).
2 "Range in any year" is the minimum and maximum effect on employment in any year in the study period.
3 "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Proposed Rule. These are calculated using assumptions related to employment per ton of coal produced.
4 The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
5 The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
6 The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Proposed Rule on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
7 "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT ES-9B. ANNUAL CHANGES IN EMPLOYMENT UNDER THE PROPOSED RULE COMPARED TO BASELINE FORECAST, FTES, 2020-2040



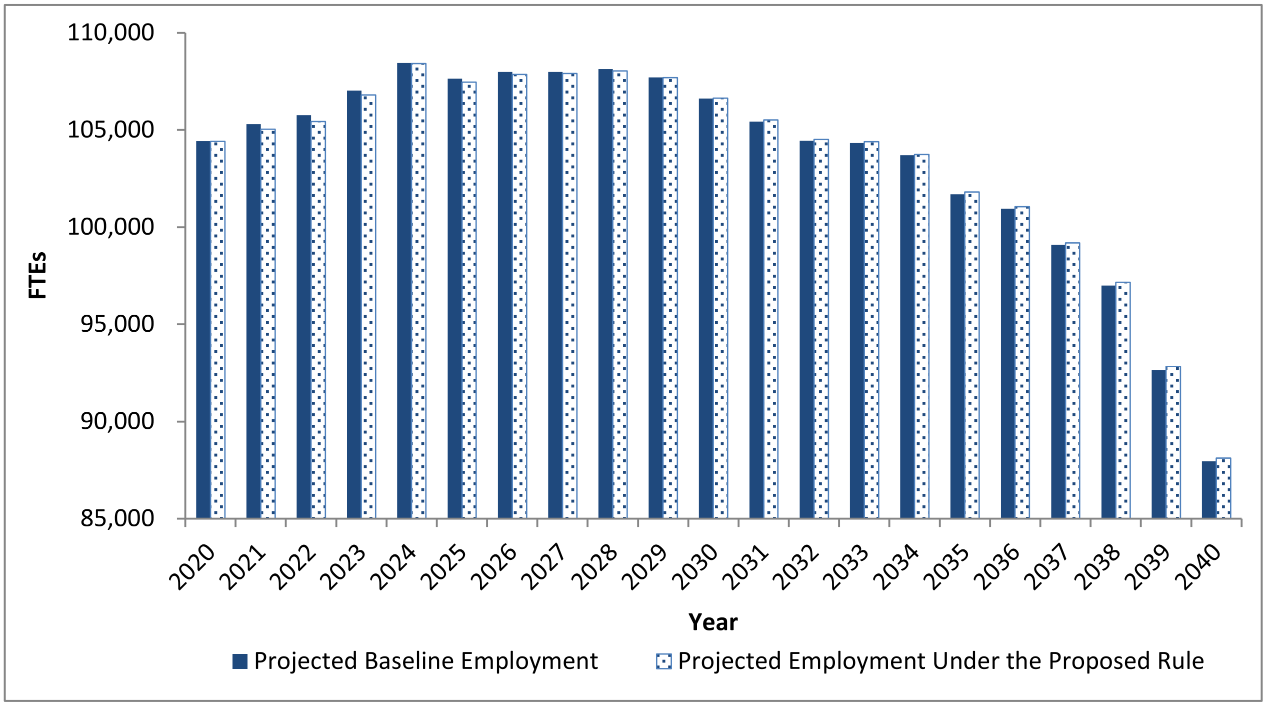
Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of the Proposed Rule. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is <u>not</u> produced because of the rule. This volume also becomes smaller over time (e.g., from -4.6 million tons in 2022 to -0.2 million tons in 2039) given that the industry is getting smaller over time. **"**Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of the rule follow the pattern of overall forecast coal production, which falls by approximately 20% over the period for analysis across the U.S. As shown, both the compliance-related and the production-related impacts of the rule are reduced over time. However, the slopes of these curves are not the same.

EXHIBIT 6-9C. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER THE PROPOSED RULE COMPARED TO BASELINE, BY REGION, (2020 TO 2040)



Notes: "Average Annual Compliance-Related" are effects on employment associated with expenditures on compliance-related activities that are expected as a result of the Proposed Rule, averaged over the study period by region. These are calculated using assumptions related to employment demand per dollar spent on compliance. "Average Annual Production-Related" are effects on employment associated with changes to coal production that are expected as a result of the Proposed Rule, averaged over the study period by region. These are calculated using assumptions related to employment per ton of coal produced.

EXHIBIT ES-9D. ANNUAL COAL INDUSTRY EMPLOYMENT UNDER BASELINE CONDITIONS AND THE PROPOSED RULE, FTES, 2020 TO 2040



Notes: As shown, coal industry employment is projected to decrease by over 15,000 FTEs under baseline conditions, i.e., due to factors unrelated to the Proposed Rule. We note that the coefficient used to estimate future employment in this exhibit leads to a somewhat greater estimate of total industry employment than is reported in some sources. For example, EIA's 2012 Annual Coal Report estimates 2012 coal industry employment to be approximately 90,000 employees (U.S. EIA. 2013a). The employment multipliers here are consistent with those applied in our production-related impacts analysis, and are conservative—specifically, we use the average multiplier for the least productive mines in each region that comprise at least 25 percent of total production in that region in order to arrive at estimates of production-related effects. Using this multiplier to present the total forecast employment level for the industry is therefore likely overestimate the total level of coal industry employment in this exhibit. The baseline number of employees is presented for display purposes--the focus of our analysis is on the incremental effects of the Proposed Rule relative to the baseline.

Most of the expected changes in jobs and regional economic activity are the result of changes in the Appalachian Basin. Reduced coal production in Appalachia would decrease employment from 41 to 450 jobs per year below baseline projections. The need to hire more labor to comply with the various provisions of the Proposed Rule would increase annual labor demand in the Appalachian region on the order of 97 to 120 jobs above baseline projections.

Not accounting for increased compliance employment, nationally surface mines see a decline in labor demand due to changes in coal production (annually between 17 to 220 jobs below baseline projections); underground mines are also expected to experience a decrease in labor demand (annually between 24 to 370 jobs below baseline projections).

In summary, the Proposed Rule is expected to reduce employment by 260 jobs on average each year due to decreased coal mined while an additional 250 jobs will be created from increased compliance activity on average each year.

CHANGES IN COAL SEVERANCE TAX REVENUES

Changes in coal production under the Proposed Rule are also expected to result in changes in coal severance tax revenue to states. To estimate the potential effect of the Proposed Rule on severance tax revenue we apply state specific effective tax rates to future production forecasts. In total, the analysis predicts an annualized decline in severance tax revenues of $2.5 million, across all coal producing states. For context, state governments collected over $1.1 billion in coal severance tax revenues across the United States in 2012. Therefore these anticipated effects would represent less than one percent of annual severance taxes collected. This decline will primarily be experienced in two states, West Virginia and Kentucky, which will bear over 80 percent of the lost severance tax revenues. These estimates are conservative for West Virginia and Kentucky as they are based on historic per-ton tax revenues while West Virginia and Kentucky severance taxes are based on the price of coal. If coal producers are able to raise prices in response to the greater compliance costs of the Proposed Rule, then coal revenues and associated severance tax revenues will be greater than estimated here for West Virginia and Kentucky.

FORECAST CHANGE IN COAL PRICES

Forecast reductions in coal production from additional compliance cost will lead to increases in coal prices paid by coal users. Under the Proposed Rule, from 2020 to 2040, coal prices are expected to increase in all regions. The largest increase will be in Central Appalachia, where an average increase of 1.2 percent is expected.

ELECTRIC UTILITY PRODUCTION COSTS

As a result of increases in the price of coal, average wholesale electricity prices are expected to increase by less than 0.1 percent across all utilities. This estimated increase, however, is highly conditional on the extent to which utilities will substitute away from coal in favor of less expensive energy sources, which cannot be forecasted with certainty. Should utilities readily substitute away from coal, the effect of the Proposed Rule on wholesale electricity would diminish.

ANALYSIS OF ALTERNATIVES

The following analysis considers seven additional alternatives to the Proposed Rule in detail.[4] Exhibits ES-10 through ES-13 summarize the forecast costs and benefits expected under these Alternatives. Alternative 9 would require the repromulgation of the currently vacated 2008 Stream Buffer Zone rule. The model mines analysis indicates that the impacts of Alternative 9 would not differ significantly from those of the No Action Alternative because current Clean Water Act requirements and policies and the state AOC and excess spoil policies have effectively achieved implementation of this Alternative in Central Appalachia, which is the region in which the 2008 Stream Buffer Zone rule would have had its greatest impact if it had remained in effect. For further discussion, please refer to Chapter 1.

[4] Note that OSMRE considered several additional alternatives. Of those, two were abandoned during the regulatory development phase. The initial analysis indicated that the impact of these alternatives of the coal mining industry would be unreasonable.

- Exhibit ES-10 summarizes the expected environmental and human health impacts of the Alternatives.
- Exhibit ES-11 summarizes the regional economic implications of the Alternatives, including expected effects on employment (Exhibits ES-11A and B) and severance taxes (Exhibit ES-11C).
- Exhibits ES-12A and 12B provide the forecast change in production under Alternatives 2-7 as an annual average and a total from 2020 through 2040.
- Exhibits ES-13A and 13B provide forecasts of compliance costs under the Alternatives.
- Exhibit ES-14 summarizes the annualized market welfare losses under each Alternative. Projected market welfare losses range from an annualized loss of $10.1 million under Alternative 6 to $100.2 million under Alternative 2.
- Exhibit ES-15 summarizes the range in percent changes in coal prices under the Alternatives across regions. Forecast changes in regional coal prices are expected to range from a decline of 0.1 percent under Alternative 6 to a gain of 4.7 percent under Alternative 2.

This analysis also considers the potential for coal "stranding" (also referred to as "reserve sterilization") to result from the Proposed Rule. "Stranding" of coal refers to the situation in which coal that would be economical to mine and technically feasible to mine is made unavailable for extraction as a result of the requirements of the rule. While forecast costs and benefits of Alternative 2 do <u>not</u> include an expectation that coal reserves will be stranded as a result of the rule, there is a greater risk of reserve stranding under this alternative than other alternatives.

EXHIBIT ES-10. SUMMARY OF ANNUAL ENVIRONMENTAL AND HUMAN HEALTH IMPACTS FOR ALTERNATIVES 2 THROUGH 9, 2020-2040

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	ALT. 2	ALT.3	ALT. 4	ALT. 5	ALT. 6	ALT. 7	ALT. 8 (PROPOSED RULE)	ALT.9	EFFECTS ON ECOSYSTEM SERVICES
Water Quality	Fewer stream miles adversely impacted, improved water quality (e.g., pH, selenium, TDS) within watershed. Potential for adverse and beneficial impacts to groundwater quality and quantity (contamination and well loss)	Stream restoration, landforming, fill design changes, and reforestation requirements; indirect effects of changes in mining activity	8 stream miles not filled; 57 stream miles restored; 26 downstream preserved stream miles; 267 downstream improved stream miles per year	0 stream miles not filled; 29 stream miles restored; 1 downstream preserved stream mile; 291 downstream improved stream miles per year	4 stream miles not filled; 29 stream miles restored; 1 downstream preserved stream mile; 291 downstream improved stream miles per year	4 stream miles not filled; 1 stream mile restored; 1 downstream preserved stream mile; 174 downstream improved stream miles per year	4 stream miles not filled; 30 stream miles restored; 1 downstream preserved stream mile; 292 downstream improved stream miles per year	4 stream miles not filled; 14 stream miles restored; 1 downstream preserved stream mile; 178 downstream improved stream miles per year	4 stream miles not filled; 29 stream miles restored; 1 downstream preserved stream mile; 292 downstream improved stream miles per year	Negligible	Increased water quality enhances ecosystem, recreational and some consumptive use services
Biological Resources	Reduced impacts to aquatic communities, habitat enhancements for threatened and endangered species	Stream restoration, landforming, reforestation and species protection requirements	Water quality benefits stated above; 2,343 acres of forest improved; 311 acres of forest preserved per year	Water quality benefits stated above; 2,836 acres of forest improved; 31 acres of forest preserved per year	Water quality benefits stated above; 2,808 acres of forest improved; 25 acres of forest preserved per year	Water quality benefits stated above; 1,346 acres of forest improved; 21 acres of forest preserved per year	Water quality benefits stated above; 0 acres of forest improved; 11 acres of forest preserved per year	Water quality benefits stated above; 1,764 acres of forest improved; 26 acres of forest preserved per year	Water quality benefits stated above; 2,811 acres of forest improved; 20 acres of forest preserved per year	Negligible	Increased quality or quantity of habitat enhances recreational opportunities and aesthetic conditions

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	ALT. 2	ALT.3	ALT. 4	ALT. 5	ALT. 6	ALT. 7	ALT. 8 (PROPOSED RULE)	ALT.9	EFFECTS ON ECOSYSTEM SERVICES
Visual Resources	Improved aesthetics	AOC requirements, landforming and reforestation requirements	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Water quality, forest, and biological resource benefits stated above	Negligible	Improved aesthetics may improve property values and the quality of recreational opportunities
Air Quality	Additional carbon storage, changes in emissions (e.g., NO_X, SO_2, PM, CH_4) from mining activity	Reforestation requirements, fill design changes, indirect effects of changes in mining activity[1]	Increased reforestation (see Biological resources above) and associated increased carbon storage; increased air pollutant emissions due to increased underground mining activity (e.g., methane emissions increase by approximately 363 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 400 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 353 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 283 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 204 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 396 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 311 million cubic feet (MMcf) per year).	Negligible	Increased carbon storage and reductions in emissions reduce human health risks and climate change-related risks

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	ALT. 2	ALT.3	ALT. 4	ALT. 5	ALT. 6	ALT. 7	ALT. 8 (PROPOSED RULE)	ALT.9	EFFECTS ON ECOSYSTEM SERVICES
Public Health	Reduced exposure to contaminants in drinking water	Stream restoration, landforming and reforestation requirements	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality benefits and biological resource benefits stated above	Negligible	Reduced probability of adverse health effects, or incurring costs to mitigate those effects
Recreation	Potential for increased recreational opportunities, improved aesthetics	Elements directly affecting water quality and biological resources (e.g., stream restoration) as well as AOC requirements and post-mining land use	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality, forest, and biological resource benefits stated above	Negligible	Increased quality or quantity of recreational fishing, hunting, wildlife viewing, or hiking opportunities
Other	Reduced risk and severity of adverse impacts, including long-term pollution discharges during and after mining	Baseline data collection, monitoring, material damage definition, corrective action thresholds	Water and air quality resource benefits as stated above	Water and air quality resource benefits as stated above	Water and air quality resource benefits as stated above	Water and air quality resource benefits as stated above	Water and air quality resource benefits as stated above	Water and air quality resource benefits as stated above	Water and air quality resource benefits stated above	Negligible	Reduced human health risks, improved recreational opportunities, improved aesthetics

Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.[1] The potential for the Alternatives to reduce air pollutant emissions is due to the aggregate effect of the rule elements on the overall level of coal mining activity. The relative effect of the Alternatives on coal production is therefore an indicator of the potential relative effect on emissions. The relative effects of the Alternatives on coal production are presented in Exhibits ES-12A and 12B.

EXHIBIT ES-11A. SUMMARY OF ANNUAL PRODUCTION-RELATED EMPLOYMENT EFFECTS FOR ALTERNATIVES 2 THROUGH 9, 2020-2040 (FTE)[1]

COAL REGION	METRIC	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7	ALTERNATIVE 8 (PROPOSED RULE)	ALTERNATIVE 9
Appalachian Basin	Average over 21 years:[2]	(520)	(310)	(250)	(220)	(120)	(270)	(210)	0
	Range in any year:[3]	(890) - (130)	(540) - (76)	(450) - (62)	(470) - (41)	(230) - (13)	(510) - (62)	(450) - (41)	0 - 0
Colorado Plateau	Average over 21 years:	0	0	0	0	0	0	0	0
	Range in any year:	0 - 0	(1) - 0	0 - 1	0 - 1	(1) - 0	0 - 1	0 - 1	0 - 0
Gulf Coast	Average over 21 years:	1	(1)	(1)	0	1	0	0	0
	Range in any year:	0 - 3	(4) - 0	(6) - 0	(1) - 2	0 - 4	(1) - 1	(3) - 2	0 - 0
Illinois Basin	Average over 21 years:	(48)	(31)	(33)	(16)	(28)	(45)	(33)	0
	Range in any year:	(140) - (1)	(100) - (2)	(110) - (1)	(60) - (1)	(130) - 1	(170) - (2)	(91) - 0	0 - 0
Northern Rocky Mountains and Great Plains	Average over 21 years:	(21)	(22)	(22)	(22)	(21)	(22)	(22)	0
	Range in any year:	(61) - 0	(66) - 0	(51) - (1)	(70) - 0	(60) - 0	(54) - 0	(66) - 0	0 - 0
Northwest	Average over 21 years:	0	0	0	0	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Western Interior	Average over 21 years:	0	0	0	0	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
TOTAL	**Average over 21 years:**	**(590)**	**(360)**	**(310)**	**(260)**	**(160)**	**(330)**	**(260)**	**0**
	Range in any year:	**(1,100) - (130)**	**(660) - (78)**	**(580) - (62)**	**(530) - (48)**	**(340) - (14)**	**(680) - (65)**	**(590) - (41)**	**0 - 0**

Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.

[1] Production-related employment effects are reported as an average and a range of expected annual effects. Employment effects from production are calculated using employment per ton of coal produced. The range of employment effects represent the minimum and maximum effect in any year in the study period when impacts on surface mining as well as underground mining employment are combined.

[2] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment.

[3] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.

EXHIBIT ES-11B. SUMMARY OF ANNUAL COMPLIANCE-RELATED EMPLOYMENT EFFECTS FOR ALTERNATIVES 2 THROUGH 9, 2020-2040 (FTE)[1]

COAL REGION	METRIC	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7	ALTERNATIVE 8 (PROPOSED RULE)	ALTERNATIVE 9
Appalachian Basin	Average over 21 years:[2]	340	190	180	140	59	170	120	0
	Range in any year:[3]	280 - 370	160 - 200	150 - 190	120 - 150	49 - 63	140 - 180	97 - 120	0 - 0
Colorado Plateau	Average over 21 years:	20	19	23	0	3	12	14	0
	Range in any year:	17 - 22	16 - 20	19 - 24	0 - 0	2 - 3	10 - 13	12 - 15	0 - 0
Gulf Coast	Average over 21 years:	44	42	45	0	4	7	30	0
	Range in any year:	44 - 45	42 - 42	44 - 45	0 - 0	4 - 4	7 - 7	30 - 31	0 - 0
Illinois Basin	Average over 21 years:	130	79	81	0	66	12	66	0
	Range in any year:	100 - 150	62 - 91	63 - 94	0 - 0	52 - 76	9 - 14	52 - 76	0 - 0
Northern Rocky Mountains and Great Plains	Average over 21 years:	35	33	36	0	4	6	21	0
	Range in any year:	31 - 37	29 - 35	32 - 38	0 - 0	3 - 4	5 - 6	19 - 22	0 - 0
Northwest	Average over 21 years:	1	1	1	0	0	0	1	0
	Range in any year:	1 - 1	1 - 1	1 - 1	0 - 0	0 - 0	0 - 0	1 - 1	0 - 0
Western Interior	Average over 21 years:	5	3	3	0	3	0	3	0
	Range in any year:	5 - 5	3 - 3	3 - 3	0 - 0	3 - 3	0 - 1	3 - 3	0 - 0
TOTAL	**Average over 21 years:**	**580**	**370**	**370**	**140**	**140**	**210**	**250**	**0**
	Range in any year:	**470 - 630**	**310 - 390**	**310 - 390**	**120 - 150**	**110 - 150**	**180 - 220**	**210 - 270**	**0 - 0**

Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.

[1] Compliance-related employment effects are reported as an average and a range of expected annual effects. Employment effects from compliance are calculated using expected changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance The range of employment effects represent the minimum and maximum effect in any year in the study period.

[2] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment.

[3] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.

EXHIBIT ES-11C. SUMMARY OF ANNUALIZED CHANGES IN SEVERANCE TAXES FOR ALTERNATIVES 2 THROUGH 9, 2020-2040 (2014 DOLLARS)

COAL REGION	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7	ALTERNATIVE 8 (PROPOSED RULE)	ALTERNATIVE 9
Appalachian Basin[1]	($4,320,000)	($2,500,000)	($2,040,000)	($1,790,000)	($1,010,000)	($2,190,000)	($1,720,000)	$0
Colorado Plateau	$108	($574)	$745	$453	$168	$1,130	$813	$0
Gulf Coast	$66	($76)	($161)	$31	$90	$10	$0	$0
Illinois Basin[1]	($785,000)	($411,000)	($349,000)	($259,000)	($205,000)	($402,000)	($307,000)	$0
Northern Rocky Mountains and Great Plains	($444,000)	($464,000)	($441,000)	($455,000)	($435,000)	($448,000)	($444,000)	$0
Northwest	$0	$0	$0	$0	$0	$0	$0	$0
Western Interior	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	**($5,550,000)**	**($3,370,000)**	**($2,830,000)**	**($2,510,000)**	**($1,640,000)**	**($3,040,000)**	**($2,470,000)**	**$0**

Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.
[1] Production in Kentucky is evenly divided between the Appalachian Basin and Illinois Basin regions.

EXHIBIT ES-12A. CHANGE IN COAL PRODUCTION (MILLION TONS), 2020-2040, ALTERNATIVES 2 THROUGH 9

ALTERNATIVE	METRIC	SURFACE	UNDERGROUND	COMBINED SURFACE AND UNDERGROUND
Alternative 2	Study Period	(112.30)	44.70	(67.60)
	Average	(5.30)	2.10	(3.20)
Alternative 3	Study Period	(24.70)	(22.60)	(47.30)
	Average	(1.20)	(1.10)	(2.30)
Alternative 4	Study Period	(23.10)	(19.90)	(43.00)
	Average	(1.10)	(0.90)	(2.00)
Alternative 5	Study Period	(21.10)	(15.80)	(36.80)
	Average	(1.00)	(0.80)	(1.80)
Alternative 6	Study Period	(17.90)	(11.20)	(29.10)
	Average	(0.90)	(0.50)	(1.40)
Alternative 7	Study Period	(23.10)	(22.60)	(45.60)
	Average	(1.10)	(1.10)	(2.20)
Alternative 8 (Proposed Rule)	Study Period	(21.40)	(17.50)	(38.90)
	Average	(1.00)	(0.80)	(1.90)
Alternative 9	Study Period	0.00	0.00	0.00
	Average	0.00	0.00	0.00
Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.				

EXHIBIT ES-12B. AVERAGE ANNUAL CHANGE IN COAL PRODUCTION UNDER ALTERNATIVES 2 THROUGH 9, 2020-2040

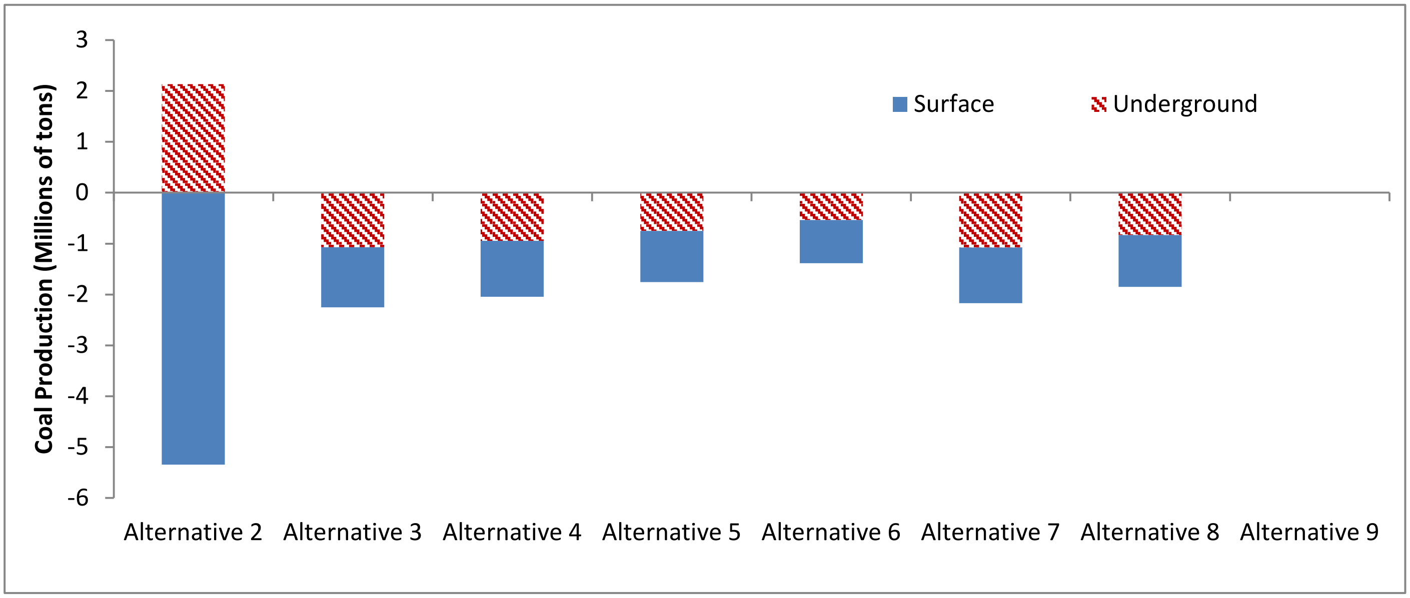
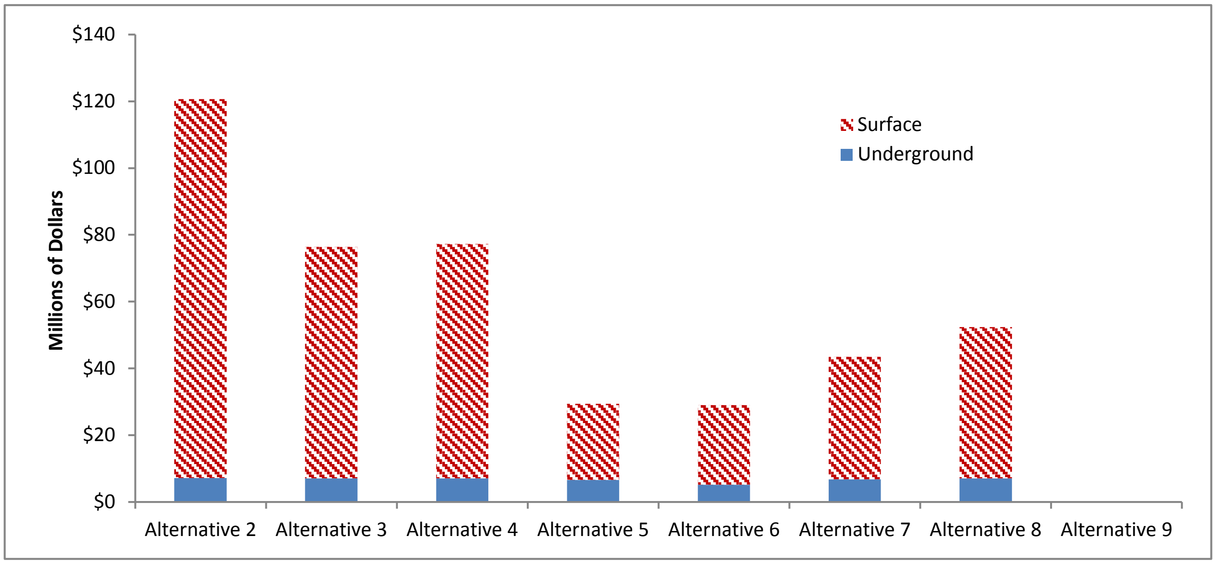


EXHIBIT ES-13A. ANNUALIZED COMPLIANCE COSTS UNDER ACTION ALTERNATIVES, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

COAL REGION	ALT. 2	ALT. 3	ALT. 4	ALT. 5	ALT. 6	ALT. 7	ALT. 8 (PROPOSED RULE)	ALT. 9
Appalachian Basin	$71,000,000	$39,300,000	$37,700,000	$29,400,000	$12,300,000	$35,600,000	$24,000,000	$0
Colorado Plateau	$3,990,000	$3,700,000	$4,440,000	$0	$552,000	$2,400,000	$2,700,000	$0
Gulf Coast	$9,020,000	$8,510,000	$ 9,050,000	$0	$853,000	$1,490,000	$6,200,000	$0
Illinois Basin	$27,300,000	$16,700,000	$17,100,000	$0	$14,000,000	$2,530,000	$14,000,000	$0
Northern Rocky Mountains and Great Plains	$7,980,000	$7,450,000	$8,190,000	$0	$852,000	$1,290,000	$4,800,000	$0
Northwest	$153,000	$126,000	$132,000	$0	$43,700	$13,600	$98,000	$0
Western Interior	$1,100,000	$664,000	$670,000	$0	$554,000	$101,000	$550,000	$0
TOTAL	**$121,000,000**	**$76,400,000**	**$77,300,000**	**$29,400,000**	**$29,100,000**	**$43,500,000**	**$52,000,000**	**$0**

Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here. Estimates may not sum to the totals presented due to rounding.

EXHIBIT ES-13B. COMPLIANCE COSTS, ANNUALIZED, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)



Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.

EXHIBIT ES-14. ANNUALIZED MARKET WELFARE EFFECTS FOR ALTERNATIVES 2 THROUGH 9, SEVEN PERCENT DISCOUNT RATE, 2020-2040 (MILLIONS, 2014 DOLLARS)

METRIC	ALT. 2	ALT. 3	ALT. 4	ALT. 5	ALT. 6	ALT. 7	ALT. 8 (PROPOSED RULE)	ALT. 9
Annualized loss over the 2020-2040 period–discounted at 7%	$100.2	$57.8	$58.7	$12.2	$10.1	$24.5	$34.1	$0

EXHIBIT ES-15. RANGE OF ANNUAL CHANGE IN COAL PRICE IMPACTS ACROSS REGIONS RELATIVE TO BASELINE (2020-2040)

PERCENT CHANGE	ALT. 2	ALT. 3	ALT. 4	ALT. 5	ALT. 6	ALT. 7	ALT. 8 (PROPOSED RULE)	ALT. 9
MINIMUM	0.2%	0.2%	0.2%	-0.1%	-0.1%	0.2%	0.2%	0%
MAXIMUM	4.7%	2.5%	1.8%	1.3%	0.5%	1.8%	1.3%	0%

Note: Alternative 1 is defined in the Environmental Impact Statement as the No Action Alternative. This is the baseline scenario and is not reported here.

[1]These values represent the percent change in Coal Price across coal supply regions (corresponding OSMRE regions identified in parenthesis): Northern Appalachia (Appalachian Basin), Central Appalachia (Appalachian Basin), Illinois Basin (Illinois Basin), Powder River Basin (Northern Rocky Mountains), and Rockies (Northern Rocky Mountains).

SMALL BUSINESS IMPACTS

The Initial Regulatory Flexibility Analysis (Appendix A) considers the extent to which the economic impacts resulting from the Proposed Rule could be borne by small businesses. Due to the complexity in corporate structures in the coal mining industry, it is difficult to calculate the exact number of small entities that could be affected by this rule; the coal mining industry is continually changing and it is common for large mining operators to merge with smaller operators, creating complicated business relationships between parent corporations and subsidiaries. For this analysis, we use two definitions: using the Small Business Administration definition of small mines (mines reporting 500 employees or less), we estimate that there were 284 small coal mining entities in 2013; using the MSHA definition of small mines (mines reporting less than 20 employees), we estimate that there were 134 small coal mining entities in 2013. Using either definition of small entities, over 90 percent of mines operated by small entities were in the Appalachian Basin. All of these entities are expected to be affected by the Proposed Rule.

The estimated compliance costs associated with the Proposed Rule for surface mines on average are expected to cost small surface mines with less than 20 employees between zero and 15.3 percent of annual revenues, depending on mining region.[5] For small surface mines reporting 500 employees or less, the average expected cost is estimated to be smaller, at between zero and 6.0 percent of revenues, depending on mining region.

The estimated compliance costs associated with the Proposed Rule on average are expected to cost small mines in Appalachia with less than 20 employees approximately 7.1 percent (surface mining) and 4.3 percent (underground mining) of annual revenues. Average compliance costs for small mines in Appalachia with 500 employees or less are estimated to be 4.7 percent (surface mining) and 2.5 percent (underground mining) of annual revenues.

[5] To be conservative, i.e., more likely to overstate than understate impacts, we include in this small entity analysis the administrative costs that will need to be paid or financed in the first year of mine operations (initial costs). Therefore, the average annual administrative costs would be expected to be lower at small mines than estimated here.

OTHER REGULATORY IMPACTS

In addition to satisfying the requirements of Executive Order 12866, this document also addresses the following analytic requirements, as enumerated in the referenced statutes and executive orders:

- **Unfunded mandates:** examines the implications of the Proposed Rule with respect to unfunded mandates as required by the Unfunded Mandates Reform Act (UMRA);
- **Energy impacts:** examines the impacts of the Proposed Rule on energy use, supply, and distribution as mandated under Executive Order 13211 (66 FR 28355, May 22, 2001);
- **Environmental justice:** considers potential issues for minority and low-income populations as required under Executive Order 12898;
- **Children's health protection:** examines the potential impact of the Proposed Rule on the health of children to comply with Executive Order 13045;
- **Tribal governments:** extends the discussion of Federal unfunded mandates to include impacts on Native American tribal governments and their communities as mandated under Executive Order 13175, “Consultation and Coordination With Indian Tribal Governments” (May 14, 1998);
- **Federalism:** considers potential issues related to state sovereignty as required under Executive Order 13132.

The reader is referred to Chapter 9 and the Initial Regulatory Flexibility Analysis for a discussion of these assessments.

UNCERTAINTIES

The table below (Exhibit ES-16) summarizes the principal categories of uncertainties in this analysis.

EXHIBIT ES-16. TREATMENT OF KEY UNCERTAINTIES IN THE REGULATORY IMPACT ANALYSIS

UNCERTAINTY	TREATMENT OF UNCERTAINTY
Compliance costs and changes in industry behavior that will be associated with this rulemaking are not known with certainty.	We developed a detailed description of each element of the rule, and conducted an engineering analysis of the expected impacts of the rule on mine operations. OSM requests comments from the public about the assumptions related to compliance costs.
Compliance costs and changes in industry behavior in response to the rule will vary by mine type and location, and according to site-specific conditions.	Because the industry is heterogeneous, we forecast impacts at 13 model mines across the U.S. to provide a representational understanding of the changes actual mines may face. In doing so, the analysis provides an overall measure of the scope and scale of potential changes under each alternative, but is not likely to be accurate with regard to any specific mining operation. Specific to longwall operations and coal refuse, OSMRE has conducted an additional analysis of potential impacts, and has requested comment on these issues in the Proposed Rule.
When compliance costs will be incurred by industry and SRAs is not known with certainty.	We estimate that all coal production from 2020 onwards will be produced in compliance with the Proposed Rule. This is likely to be conservative, since some coal production will be grandfathered.
Future coal demand is not known with certainty.	Three baseline coal demand scenarios are estimated. In addition to the most likely to occur scenario, "high coal demand" and "low coal demand" scenarios are conducted.
Future coal supply is not known with certainty.	The method for forecasting future coal production is detailed in Chapter 5 of this analysis. The resulting forecast is compared against other published coal forecasts (specifically, EIA).
Whether or not the Proposed Rule will result in permitting delays is unknown.	The analysis qualitatively discusses the potential for the Proposed Rule to result in additional permit delays. OSMRE has asked for public comment on this issue.
Market Model Uncertainty: The suite of models that we employ to assess changes in coal production and pricing under the Proposed Rule include a rich representation of coal market dynamics. Nevertheless, as a stylized representation of these markets, the models may not capture variables that are difficult to observe and/or measure (e.g., coal production costs by mine). In addition, the model relies on several exogenous forecasts, any of which may affect model results (e.g., GDP growth, the strength of the U.S. dollar, etc.). The impact of these uncertainties on the results of our analysis is unknown.	To minimize uncertainty, the EVA market models rely on disaggregated data (e.g., for individual power plants) where possible to capture the likely response of regulated entities.
Estimates of the future environmental impacts from this rule rely on assumptions about industry behavior, market conditions, and site-specific conditions.	The model mines analysis is used in each coal region to arrive at quantified estimates of the environmental impacts of the rule in terms of reducing the number of degraded stream miles, increasing the number of forested acres protected or restored, and reducing air emissions from mining operations. A number of other categories are described qualitatively.
Future regulatory initiatives that could impact the industry are not known.	The analysis identifies existing and potential environmental regulations that are expected to influence mining practices / coal demand and legislative initiatives to reduce greenhouse gas emissions.

CHAPTER 1 | INTRODUCTION AND REGULATORY OPTIONS

The Office of Surface Mining Reclamation and Enforcement (OSMRE) is considering revising its regulations to more fully implement the Surface Mining Control and Reclamation Act of 1977 (SMCRA) (30 U.S.C. §§ 1201-1328). These proposed revisions seek to improve the balance between the Nation's need for coal as an essential energy source and the protection of streams, fish, wildlife, and related environmental values from the adverse impacts of surface coal mining.

The purpose of this regulatory impact analysis is to describe the economic and social costs and benefits that will result from the proposed Stream Protection Rule (Proposed Rule).

1.1 THE STREAM PROTECTION RULE: MAJOR ELEMENTS

This analysis considers nine separate regulatory Alternatives, including the Baseline (No Action). The Proposed Rule is based on 11 principal elements developed by OSMRE to achieve the regulatory objectives and to aid in the evaluation of each of the nine Alternatives being considered. For ease of discussion and analysis, OSMRE has organized these 11 principal rulemaking elements into four "functional groups"; each group contains common or related characteristics. The functional groups and major elements consist of the following:

- Protection of the hydrologic balance;
    - Baseline data collection and analysis,
    - Monitoring during mining and reclamation,
    - Material damage definition, and
    - Corrective action thresholds
- Activities in or near streams;
    - Stream definitions,
    - Mining through or diverting streams, and
    - Activities in or near streams
- Approximate original contour (AOC) and AOC variances; and
    - Surface mine and fill configuration, and
    - Approximate original contour requirements
- Postmining land use and enhancement

- o Revegetation and soil management, and
- o Fish and wildlife protection and enhancement.

In the initial Notice of Intent (NOI) to prepare an environmental impact statement (April 30, 2010), these 11 elements included: baseline requirements; definition of material damage; activities in, near or through streams; monitoring requirements; corrective action thresholds; surface configuration; variances to approximate original contour requirements; enhanced reforestation activities; permit coordination between agencies; long-term financial assurances; and stream definitions.

In light of the comments received during scoping, OSMRE revised this list of elements. For example, this RIA considers “mining through streams” and “activities that occur ‘in or near’ streams” as separate principal elements. OSMRE believes these two rule changes are sufficiently different from one another to warrant separation and development as individual elements. Mining *through streams* in most cases means that the coal deposits below the stream will be removed during the mining operation and, during reclamation, the stream channel will be reconstructed. Mining *in or near streams* implies some activity taking place within a stream buffer zone but does not include removal of the stream bed to extract coal.[1,2]

The following table summarizes each of the 11 analyzed elements.

EXHIBIT 1-1. MAJOR ELEMENT DEFINITIONS

MAJOR ELEMENT	ELEMENT DEFINITION
Baseline Data Collection & Analysis	The extent to which each alternative provides accurate hydrologic characterization including baseline data on hydrology, geology, and aquatic biology to enable the Regulatory Authority to make better permitting decisions.
Monitoring During Mining & Reclamation	The extent to which each alternative addresses requirements for monitoring to identify conditions that could lead to material damage to the hydrologic balance.
Material Damage Definition	The extent to which each alternative provides a definition that prevents an unacceptable level of adverse impact to the hydrologic balance outside the permit area.
Corrective Action Thresholds	The extent to which each alternative requires setting corrective action thresholds for parameters related to potential material damage to the hydrologic balance.
Stream Definitions	The extent to which each alternative provides a common definition of perennial, intermittent, and ephemeral streams to allow greater clarity and protection.
Mining Through or Diverting Streams	The extent to which each alternative addresses conditions under which mining through a stream would be allowed.
Activities In or	The extent to which each alternative addresses the circumstances under which an operator could engage in mining or mining-related activities in or near a stream,

[1] Some examples of activities ’in or near streams’ include placement of sedimentation controls or water treatment facilities, deposition of excess spoil or coal refuse, and construction of stream crossings.

[2] OSMRE has also added fish and wildlife protection and enhancement as a principal element and has expanded the enhanced reforestation element to include revegetation, reforestation, and topsoil management.

MAJOR ELEMENT	ELEMENT DEFINITION
Near Streams	including placement of excess spoil or coal waste.
Surface Mine and Fill Configuration	The extent to which each alternative incorporates landforming principles into reclamation plans requiring post-mined land to more closely resemble the pre-mining landscape.
Approximate Original Contour (AOC) Requirements	The extent to which each alternative ensures that AOC variances meet safety, hydrologic, and post-mining land use criteria and that they are consistent with post-mining land use and are achievable and feasible.
Revegetation & Soil Management	The extent to which each alternative requires (1) soil reconstruction in a manner that will restore or improve the site's capability to support native forest; i.e., maintain or improve the site index, and (2) requires revegetation with native species in a manner that will restore native ecosystems.
Fish & Wildlife Protection & Enhancement	The extent to which each alternative minimizes disturbances to or adverse impacts on fish, wildlife, and related environmental values and requires enhancement of those resources.
Source: Adapted from SPR EIS Chapter 2.	

1.2 EXAMINATION OF ALTERNATIVE REGULATORY OPTIONS

This section describes the Alternatives being considered for the Proposed Rule. The Alternatives include the Baseline, i.e., conditions absent this regulatory action. In addition to the Baseline, Alternatives include the Proposed Rule and seven Alternatives.

The four terms, defined below, are used extensively in the description of the Alternatives:

- Mining through – actually going in to mine out the coal from below the stream bed; relocating the stream.
- Mining in – refers to other sorts of mining-related activities occurring in the stream such as waste disposal, related facilities, and not just the actual mining itself.
- Excess spoil – Refers to extra materials (such as rock but excluding topsoil) that were removed to get at the coal underneath and that after being disturbed are too large in volume to put back into the area from which they were originally taken.
- Coal mine waste – Refers to earth materials, which are combustible, physically unstable, or acid-forming or toxic-forming, wasted or otherwise separated from the coal product.

ALTERNATIVE 1 (NO ACTION ALTERNATIVE)

This alternative consists of current regulatory requirements under SMCRA. There would be no new regulations under SMCRA, so any added stream protection would depend on actions by individual states and by the U.S. Environmental Protection Agency and U.S. Army Corps of Engineers under the Clean Water Act.

All mining activities in a perennial or intermittent stream, or on the surface of land within 100 feet of a perennial or intermittent stream, would continue to be prohibited unless the regulatory authority specifically authorizes activities closer to, or through, such a stream. The regulatory authority may authorize such activities only upon finding that (1) the mining activities would not cause or contribute to the violation of applicable state or Federal water quality standards and would not adversely affect the water quantity and quality or other environmental resources of the stream, and (2) any temporary or permanent stream-channel diversion would comply with the performance standards for diversions.

Mining through perennial and intermittent streams would continue to be allowed, provided that restored stream channels for perennial and intermittent streams (or permanent diversion channels for those streams) are designed and constructed so as to restore or approximate the premining characteristics of the original stream channel, including the natural riparian vegetation.

There would continue to be no restrictions on mining in or through ephemeral streams, nor would there be any requirements for restoration of ephemeral streams after mining.

Other Key Points:

- Would not require any Federal or state rule changes.
- Would not have any additional adverse economic impacts on the coal mining industry.
- Would not be consistent with the spirit and intent of the 2009 Memorandum of Understanding (MOU) on implementing the interagency action plan on Appalachian surface coal mining.
- Would not achieve any added stream protection.
- Would not require improved mining and reclamation practices, which means there likely would be little improvement in land use capability after mining, revegetation with native species, use of geomorphic reclamation and landforming practices to promote more stable erosional features, or fish and wildlife enhancement.
- Would not define material damage to the hydrologic balance outside the permit area, which means interpretation and application of a key provision of SMCRA would remain at the discretion of each regulatory authority.
- Would not specifically address dewatering of streams by subsidence from underground mining.
- Would not require sufficient baseline data and improved water monitoring to fully evaluate the impacts of mining on surface water and groundwater.
- Would not establish any objective standards for determining restoration of the approximate original contour.

ALTERNATIVE 2 (MOST ENVIRONMENTALLY PROTECTIVE)

This alternative would prohibit all mining activities in or within 100 feet of perennial streams. It would allow mining through intermittent streams only if the applicant can demonstrate that the hydrologic form and ecological function of intermittent streams can and would be restored. It would prohibit the placement of excess spoil in both perennial and intermittent streams. It would place no new restrictions on activities in ephemeral streams.

It would allow no exceptions for steep-slope mining operations and mountaintop removal mining operations from the requirement to restore mined lands to their approximate original contour.

This alternative would define the term "material damage to the hydrologic balance outside the permit area" as "any quantifiable adverse impact from surface or underground mining operations that would preclude any designated use of the affected stream segment under the Clean Water Act." This alternative would require that the permit include corrective action thresholds at which the permittee must take action to prevent continued degradation or material damage to the hydrologic balance.

Other Key Points:

- Would be consistent with the spirit and intent of the 2009 MOU) on implementing the interagency action plan on Appalachian surface coal mining.
- Would provide the highest level of stream protection of all alternatives under consideration.
- Would define material damage to the hydrologic balance outside the permit area, thus providing a foundation for evaluations of state regulatory program provisions and practices on this topic.
- Would require that each permit establish corrective action thresholds to ensure that adverse impacts from mining never attain material damage levels.
- Would prohibit permanent dewatering of perennial and intermittent streams by subsidence from underground mining.
- Would require vastly improved baseline data and water monitoring to fully evaluate the impacts of mining on surface water and groundwater.
- Would require improved mining and reclamation practices, which would result in improvement in land use and soil capability after mining, revegetation with native species, reforestation, use of geomorphic reclamation and landforming practices to promote establishment of more stable and natural surface water runoff features, and fish and wildlife enhancement.
- Would establish objective standards for determining restoration of the approximate original contour.

- Would require use of backfilling, regrading, and excess spoil fill construction techniques that are designed to minimize leaching of elements that result in increased conductivity or other adverse impacts on aquatic organisms in streams.
- Would require amendment of SMCRA to prohibit exceptions from the requirement to restore mined lands to their approximate original contour.

ALTERNATIVE 3

This alternative would allow mining in or through intermittent and perennial streams, but only if the hydrologic form and ecological function of those streams can be restored. No restriction would be placed on mining in or through ephemeral streams. This alternative would prohibit the placement of excess spoil or coal mine waste in perennial streams, but not in ephemeral or intermittent streams.

Exceptions to approximate original contour restoration requirements would be allowed only if they do not result in damage to natural watercourses on or off the permit area. This alternative would define the term “material damage to the hydrologic balance outside the permit area” as any quantifiable adverse impact from surface or underground mining operations that would preclude any designated use of the affected stream segment under the Clean Water Act.” The permit must include corrective action thresholds at which the permittee must take action to prevent continued degradation or material damage to the hydrologic balance.

Other Key Points:

- Similar to Alternative 2 in terms of environmental protection except that it would not—
  - Provide absolute protection to perennial streams.
  - Prohibit all exceptions from the approximate original contour restoration requirement.
  - Establish objective standards for determining restoration of the approximate original contour.

ALTERNATIVE 4

This alternative would allow mining in or through intermittent and perennial streams, but only if the hydrologic form and ecological function of those streams can be restored. No restriction would be placed on mining in or through ephemeral streams. This alternative would prohibit placement of excess spoil or coal mine waste in intermittent or perennial streams unless long-term adverse impacts are offset through fish and wildlife enhancement. No restriction would be placed on placement of excess spoil or coal waste in ephemeral streams.

Exceptions to approximate original contour restoration requirements would be allowed only if they do not result in damage to natural watercourses on or off the permit area. This alternative would define the term “material damage to the hydrologic balance outside the permit area” as “any quantifiable adverse impact from surface or underground mining operations that would preclude any designated use of the affected stream segment under the Clean Water Act." The permit must include corrective action thresholds at which the permittee must take action to prevent continued degradation or material damage to the hydrologic balance.

Other Key Points:

- Similar to Alternative 3 in terms of environmental protection except that it would—
  - Not include an absolute prohibition on placement of excess spoil or coal mine waste in perennial streams.
  - Establish objective standards for determining restoration of the approximate original contour.

ALTERNATIVE 5

This alternative would apply only to those mining operations that would produce excess spoil and propose to dispose of that spoil outside the mine pit, or that would propose to place coal mine waste in intermittent or perennial streams. If one or the other of these circumstances applies, then under Alternative 5 the applicant could mine in or through intermittent and perennial streams, but only if the hydrologic form and ecological function of those streams can be restored.

If neither of these circumstances applies, the mining operation would be conducted under the existing rules (No Action Alternative), including those involving mining in or through streams.

In either instance, no restriction would be placed on mining in or through ephemeral streams. No restriction would be placed on placement of excess spoil or coal waste in ephemeral streams.

In either instance, this alternative would not include a definition of material damage to the hydrologic balance or require corrective action thresholds.

Other Key Points:

- Similar to Alternative 4 in terms of environmental protection for the lands to which it would apply except that it would not—
  - Define material damage to the hydrologic balance outside the permit area.
  - Require establishment of corrective action thresholds.
  - Establish objective standards for determining restoration of the approximate original contour.
  - Require use of landforming techniques to establish a more natural drainage pattern and more natural appearance.

- Would have almost no environmental protection benefits outside central Appalachia because there is almost no excess spoil or coal mine waste placement in perennial or intermittent streams outside that area.

ALTERNATIVE 6

This alternative would apply only to surface disturbances in or within 100 feet of a perennial or an intermittent stream. This alternative would prohibit mining activities in or within 100 feet of intermittent or perennial streams unless the applicant demonstrates to the satisfaction of the regulatory authority that:

(1) The ecological function of the stream would be protected or restored.

(2) Placement of excess spoil or coal mine waste in or near the stream would not result in the creation of acid or toxic mine drainage.

(3) Long-term adverse impacts (including impacts within the footprint of any fill) to the environmental resources of the stream would be offset in the same or adjacent watershed through fish and wildlife enhancement commensurate with the adverse impacts.

(4) Other proposed mining activities within the stream buffer zone, but not within the stream itself, would not adversely affect the water quantity and quality or other environmental resources of the stream. When disturbances within 100 feet of a perennial or an intermittent stream did occur, this alternative would require establishment of an appropriately-vegetated 100-foot riparian corridor along the entire reach of all streams (including ephemeral streams) within the permit area after mining is completed.

All mining operations outside the stream buffer zone; i.e., more than 100 feet away from a perennial or intermittent stream, would proceed as under the No Action Alternative.

Other Key Points:

- Similar to Alternative 4 in terms of environmental protection for the lands to which it would apply except that it would not—
  - Define material damage to the hydrologic balance outside the permit area.
  - Require establishment of corrective action thresholds.
  - Establish objective standards for determining restoration of the approximate original contour.
  - Require use of landforming techniques to establish a more natural drainage pattern and more natural appearance.
  - Require use of backfilling and grading techniques that would minimize impacts of leachate on conductivity levels in streams and other adverse impacts on aquatic life.
  - Include any new limitations on exceptions from the approximate original contour restoration requirement.

    - Require salvage of subsoil and organic matter to preserve land use capability and improve ecological restoration.
    - Require use of native species or reforestation.
    - Require fish and wildlife enhancement measures.
- Would be limited to activities in or near perennial and intermittent streams, which means that it would have almost no environmental protection benefits outside the stream buffer zone. This limitation also would impair efforts to protect streams overall because mining impacts on streams are not necessarily limited to activities in or within 100 feet of those streams.

ALTERNATIVE 7

This alternative would apply when certain conditions exist within the proposed permit area that warrant enhanced permitting requirements. Those conditions would include—

- The presence of areas with pristine or unique hydrologic environments.
- The presence of geologic strata known to produce acid or toxic mine drainage.
- Watersheds with waters listed as impaired under section 303(d) of the Clean Water Act, if the parameter causing the impairment could be exacerbated by mining activities.
- The presence of steep-slope areas.
- Proposals to place excess spoil or coal mine waste in perennial or intermittent streams or their buffer zones.

When these circumstances apply, this alternative would prohibit all mining activities in or within 100 feet of perennial streams. It would allow mining through intermittent streams if the applicant can demonstrate that the hydrologic form and ecological function of intermittent streams can and would be restored. It would prohibit the placement of excess spoil in intermittent streams. It would not include a definition of material damage to the hydrologic balance, but would require corrective action thresholds. It would place no new restrictions on activities in ephemeral streams.

For operations where enhanced permitting conditions were not warranted the requirements would remain the same as under the No Action Alternative.

Other Key Points:

- Similar to Alternative 4 in terms of environmental protection for those operations to which it would apply except that it would not include—
    - A definition of material damage to the hydrologic balance outside the permit area.
    - Additional restrictions on exceptions to the requirement to restore the approximate original contour.

- Environmental protection benefits may be sharply restricted because of the limited scope of this alternative, which would not apply to all operations.
- Difficult to reduce to rule language.

ALTERNATIVE 8 (PREFERRED ALTERNATIVE)

This alternative is comprised of selected primary stream protection elements of the other action alternatives analyzed. These elements include: defining material damage to the hydrologic balance outside the permit area, enhancing baseline data collection and analysis, expanding water and stream monitoring requirements, requiring restoration of the ecological function of perennial and intermittent streams that are mined through, requiring fish and wildlife offsets for perennial and intermittent stream reaches buried by excess spoil or coal mine waste, placing additional restrictions on mountaintop removal mining operations and steep-slope mining operations that seek variances from approximate original contour restoration requirements, and requiring revegetation with native species, including reforestation of previously forested areas.

Other Key Points:

- Similar to Alternative 2 in terms of environmental protection except that it would not—
  - Provide absolute protection to perennial streams.
  - Prohibit all exceptions from the approximate original contour restoration requirement.
  - Establish objective standards for determining restoration of the approximate original contour.

ALTERNATIVE 9 (2008 STREAM BUFFER ZONE RULE)

Under this alternative, mining activities that would occur on the surface of land within 100 feet of perennial and intermittent streams would be allowed if the regulatory authority finds that avoidance is not reasonably possible and that the prohibition of these activities is not needed to meet fish and wildlife and hydrologic balance protection requirements. Where these activities would require covering or mining through the stream, the regulatory authority can approve the proposed activity only if there is no reasonable alternative. Restoration of stream ecological functions would not be required.

The requirements of this alternative would not apply to placement of coal preparation plants located outside the permit area of a mine.

This alternative would also require minimization of excess spoil and prohibits construction of fills with a larger capacity than needed. However, this alternative does not include many of the elements of the other alternatives.

Other Key Points:

- Similar to the No Action Alternative in that it would not —

- Provide a definition of material damage to the hydrologic balance outside the permit area.
- Include additional restrictions on exceptions to the requirement to restore the approximate original contour.
- Include biological or additional chemical characteristics to define streams.
- Provide for corrective action thresholds.
- Increase monitoring requirements, in frequency or scope, during mining and reclamation.
- Require restoration of stream ecological function.

1.3 TIMELINE FOR IMPLEMENTATION OF THE RULE

The onset of costs and benefits of the Proposed Rule will depend, in part, on the assumed timeline for implementation of the rule. Sixty days after OSMRE's final Stream Protection Rule is published in the *Federal Register*, it will take effect in states with Federal programs (currently Tennessee and Washington State) and on Indian lands.[3] Implementation in states with approved regulatory programs may take up to 42 months to develop regulations and policies consistent with this rulemaking. While there is some uncertainty as to the speed at which States with primacy (known as State Regulatory Authorities or SRAs) will implement the new rule, we assume the following for purposes of this analysis, based on OSMRE's past experience:

- **Federal Program States and "Indian lands":**
  - Rule takes effect 60 days after publication in the *Federal Register*.
  - Permit applications approved after that date must comply with the rule.
  - Existing operations must comply with certain provisions of the new performance standards no later than the time of permit renewal (within five years).[4]
- **State Programs:**
  - The SPR is expected to take effect in SRAs within 42 months from the final rule publication in the Federal Register. This estimate incorporates the following assumed timeline:
    - OSMRE typically sends 30 CFR Part 732 notifications to all states within 90 days after publication of the final rule in the *Federal Register*, requiring the states to amend their programs to be no less effective than the revised Federal rules.

[3] Indian lands include "all lands, including mineral interests, within the exterior boundaries of any Federal Indian reservation, notwithstanding the issuance of any patent, and including rights-of-way, and all lands including mineral interests held in trust for or supervised by an Indian tribe" (P.L. 95-87. Surface Mining Control and Reclamation Act of 1977).

[4] For purposes of this analysis these are assumed to be 30 CFR sections 774.15, 800.18, 800.40, 816.35/36, 817.35/36 and 816/817.41.

        - Within 60 days of receipt of a 30 CFR Part 732 notification, each state typically submits for OSMRE approval either a proposed program amendment or an action plan with a timeline for submission of such an amendment.
        - States typically take up to 18 months to develop program amendments after receipt of OSMRE's notification.
        - OSMRE regulations require review and approval of state program amendments within seven months of submission.
        - States must implement the approved program amendments within one year from date of OSMRE approval.
    - Permit applications approved after the effective date of approved state regulations must comply with the amended state programs.
    - Subsequent to the effective date of approved state regulations, existing mining operations would have to comply with new performance standards no later than the time of permit renewal (within five years).

1.4 ANALYTICAL REQUIREMENTS MET BY THIS RIA

This RIA evaluates the benefits and costs of the Proposed Rule, along with other economic, distributional, and equity impacts. This RIA satisfies the requirements for regulatory review under **Executive Order 12866 (E.O. 12866) –** ***Regulatory Planning and Review*****. E.O. 12866** (1993, as amended by Executive Order 13563 (2011)), which directs Federal agencies to consider the costs and benefits of available regulatory Alternatives and to select approaches that maximize net benefits, unless a statute requires another regulatory approach. OMB's Circular A-4 further elaborates on the characteristics of a "good" regulatory analysis. Specifically, Circular A-4 states that an economic analysis should provide information allowing decision makers to determine that:

- there is adequate information indicating the need for and consequences of the regulatory action;
- the potential benefits to society justify the potential costs, recognizing that not all benefits and costs can be described in monetary or even in quantitative terms, unless a statute requires another regulatory approach;
- the regulatory action will maximize net benefits to society (including potential economic, environmental, public health and safety, and other advantages; distributional impacts; and equity), unless a statute requires another regulatory approach;
- where a statute requires a specific regulatory approach, the regulatory action will be the most cost-effective, including reliance on performance objectives to the extent feasible; and

- agency decisions are based on best reasonably obtainable scientific, technical, economic, and other information.[5]

This analysis also addresses several other statutory and legislative requirements related to evaluation of Federal actions. In particular, the analysis addresses requirements related to the following:

- **Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996**. The RFA (codified at 5 U.S.C. §§ 601-612), as amended by SBREFA (Pub. L. 104-121), requires Federal agencies to prepare a regulatory flexibility analysis and take other steps to assist small entities -- unless the agency certifies that a rule will not have a "significant economic impact on a substantial number of small entities." The Small Business Administration's (SBA) *A Guide for Government Agencies: How to comply with the Regulatory Flexibility Act* walks Federal agencies through the process of preparing screening analyses and initial and final regulatory flexibility analyses.
- **Unfunded Mandates Reform Act (UMRA) of 1995.** UMRA (codified at 2 U.S.C. § 1501 *et seq.*) requires Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, Federal agencies must prepare a written statement, including a cost-benefit analysis, for rules that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year.
- **E.O. 13211 – *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*.** E.O. 13211 directs Federal agencies to "weigh and consider the effects of the Federal Government's regulations on the supply, distribution, and use of energy." Agencies must prepare a Statement of Energy Effects for regulations meeting the definition of a "significant energy action."
- **E.O. 12898 – *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations.*** E.O. 12898 directs Federal agencies to prioritize achieving environmental justice by identifying and addressing disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and low-income populations.
- **E.O. 13045 – *Protection of Children from Environmental Health Risks and Safety Risks.*** E.O. 13045 directs Federal agencies and departments to evaluate the health effects of health-related or risk-related regulations on children. For economically significant rules concerning an environmental health or safety risk that may disproportionately affect children, E.O. 13045 also requires an

[5] Office of Management and Budget (OMB). 2003. Circular A-4: Guidance on Development of Regulatory Analysis. Issued September 17, 2003.

explanation as to why the planned regulation is preferable to other potentially effective and feasible Alternatives.

- **E.O. 13175 –** ***Consultation and Coordination with Indian Tribal Governments.*** **E.O. 13175 and Secretarial Order 3317 –** ***Department of the Interior Policy on Consultation with Indian Tribes***, address related unfunded mandate concerns with respect to the sovereignty of tribal governments, and impose requirements on Federal agencies to develop accountable processes to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."
- **E.O. 13132 –** ***Federalism.*** E.O. 13132 requires agencies to develop a process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the Executive Order to include regulations that have "substantial direct effects on the States [in terms of compliance costs], on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." In addition, policies have federalism implications if they preempt State law.

1.5 STATEMENT OF NEED

NEED FOR THE FEDERAL ACTION

The need for this Federal action is to improve implementation of SMCRA to ensure protection of the hydrologic balance, and reduce impacts to streams, fish, wildlife, and related environmental values. OSMRE has identified several subcomponents of that need: First, there is a need to clearly define the point at which adverse mining impacts on groundwater and surface water (both of which provide streamflow) reach an unacceptable level; that is, the point at which they cause material damage to the hydrologic balance outside the permit area. Second, there is a need to collect adequate premining data about the site of the proposed mining operation and adjacent areas to establish a comprehensive baseline against which the impacts of mining can be compared. Third, there is a need for effective monitoring of groundwater and surface water during and after mining and reclamation activities to provide real-time information on the impacts of mining and to enable prompt detection of any adverse trends and implementation of corrective measures before it is either too late to take remedial measures or exceedingly costly to do so. Fourth, there is a need to ensure protection or restoration of perennial and intermittent streams and related resources including fish and wildlife, especially within the headwaters streams that are critical to maintaining the ecological health and productivity of downstream waters. Fifth, there is a need to ensure the use of objective standards in making important regulatory and operational decisions with a potential impact on perennial and intermittent streams. Sixth, there is a need to ensure that permittees and regulatory authorities make use of advances in information, technology, science, and methodologies related to surface and groundwater hydrology, surface-runoff management, stream restoration, soils, and revegetation.

NEED FOR REGULATORY IMPROVEMENTS

SMCRA Section 201(c) requires OSMRE to "publish and promulgate such rules and regulations as may be necessary to carry out the purposes and provisions of this Act." Congress identified stream protection as a fundamental purpose of SMCRA. Among its findings in support of the legislation, Congress determined that:

> many surface coal mining operations result in disturbances of surface areas that burden and adversely affect commerce and the public welfare by … polluting the water, by destroying fish and wildlife habitats, by impairing natural beauty, … and by counteracting governmental programs and efforts to conserve soil, water, and other natural resources.

The Federal action analyzed in the SPR DEIS will better prevent or remediate the adverse impacts that Congress described when it made this finding. Despite the enactment of SMCRA and the promulgation of Federal regulations implementing the statute, surface coal mining operations continue to have negative effects on streams, fish, and wildlife. These conditions are documented in the literature surveys and studies discussed in Chapter 4. Further evidence is available through several decades of observing the impacts of coal mining operations. These documented and observed problems have prompted OSMRE to consider whether it should take a different approach in the regulations implementing the following SMCRA provisions related to stream protection:

- Section 510(b)(3) of SMCRA requires that each surface coal mining operation be designed to prevent material damage to the hydrologic balance outside the permit area. Current regulations intentionally do not define the extent of damage that is allowable and how much damage constitutes "material damage," an approach that was intended to afford regulatory authorities flexibility in making determinations on a case-by-case basis (48 FR 43973, September 26, 1983).
- Section 515(b)(2) of SMCRA requires that mined land be restored to a condition capable of supporting the uses that it was capable of supporting prior to mining, or higher or better uses of which there is reasonable likelihood, provided certain conditions are met. Existing rules and permitting practices have focused primarily on the land's suitability for a single approved post-mining land use. OSMRE believes it is essential to ensure that land be restored to support all uses that it was capable of supporting before mining.
- Section 515(b)(10) of SMCRA requires that operators minimize disturbances to the prevailing hydrologic balance at the mine site and to the quality of water in surface and ground water systems. As discussed in more detail in Chapter 2, in order to provide the most effective implementation of this statutory requirement, OSMRE is evaluating a number of options. OSMRE is considering how buffer zones may be most effectively used to minimize disturbances to the hydrologic balance and to water quality. OSMRE is evaluating regulatory options for

avoidance of acid and toxic drainage from mine sites. OSMRE also seeks the most effective regulation of excess spoil fill construction, because of the potential effects of such fills to effect the hydrologic balance and water quality.

- Sections 515(b)(19) and 516(b)(6) of SMCRA require the operator to establish a diverse, effective, permanent vegetative cover of the same seasonal variety native to the area on all regraded areas and other lands affected by mining. However, evidence indicates that areas which were previously forested have commonly been reclaimed and revegetated as heavily compacted grasslands with scrub trees--vegetation that is not representative of native pre-mining vegetation. OSMRE is considering alternatives that would implement these SMCRA provisions more effectively.
- Sections 515(b)(24) and 516(b)(11) of SMCRA require, subject to certain limitations, that surface coal mining and reclamation operations minimize disturbances and adverse impacts on fish, wildlife, and related environmental values. These provisions also require operations to "achieve enhancement of such resources where practicable." Reconstructed streams, however, often neither look nor function the way they did before mining. The regulatory emphasis has been primarily upon creating a channel sufficient to convey postmining flows, while minimizing channel erosion and sediment loading. Such limited reclamation results in streams that may no longer support the benthic and other aquatic communities that they did before mining. Additionally, efforts to enhance fish, wildlife, and related environmental values despite the mandate of both the statutes and the regulations, have not been evenly implemented as part of state reclamation programs. Examples exist of highly successful enhancement projects, while in other areas of the nation, these activities are unfortunately limited.
- OSMRE's current rules at 30 CFR § 816.73 allow excess spoil fills to be constructed by end-dumping. With end-dumping, operators push or dump rock overburden over the side of the mountain to cascade into the valley below, with the larger rocks rolling to the bottom of the valley to form the underdrain. Based on several decades' experience implementing the rules, OSMRE is reexamining whether this technique violates a number of SMCRA requirements. For instance, some end-dumping may not comply with Section 515(b)(22)(A) of SMCRA which provides that all excess spoil material resulting from surface coal mining operations must be "transported and placed in a controlled manner in position for concurrent compaction and in such a way to assure mass stability and to prevent mass movement." End-dumping, moreover, can result in elevated dissolved ion concentrations in water leaving the site, and significant increases in concentrations of total dissolved solids (TDS) in receiving streams, both of which may adversely affect fish and wildlife in contravention of section 515(b)(24) of SMCRA. Further, construction of end-dumped rock fills can result in inconsistent development of the underdrains required under section 515(b)(2) of SMCRA, leading to structural instability of the fill.

NEED FOR ADEQUATE DATA

To effectively evaluate the impacts of a mining operation, and to ensure implementation of SMCRA's requirements, the regulatory authority must have both sufficient baseline data and sufficient data about ongoing changes to stream-related resources and biota. Adequate data about the conditions before the mining activity is critical to ascertaining the extent and cause of any changes that do occur after mining is underway; this information in turn is critical to correcting problems if and when they occur. To ensure that the necessary corrections can be made to prevent and mitigate damage, the regulations must specify the types of information that need to be collected, and the locations, timing, and frequency of information collection. As discussed above, section 510(b)(3) of SMCRA requires that each surface coal mining operation be designed to prevent material damage to the hydrologic balance outside the permit area. Section 515(b)(10) of SMCRA requires, in essence, that surface coal mining and reclamation operations "minimize the disturbances to the prevailing hydrologic balance at the mine-site and in associated offsite areas and to the quality and quantity of water in surface and ground water systems both during and after surface coal mining operations and during reclamation." For underground mining, section 516(b)(9) of SMCRA requires operations to minimize disturbances to the prevailing hydrologic balance at the mine-site and associated offsite areas, and to ensure the quantity of water. Sections 515(b)(24) and 516(b)(11) of SMCRA require, subject to certain limitations, that surface coal mining and reclamation operations minimize disturbances and adverse impacts on fish, wildlife, and related environmental values; and also require operations to "achieve enhancement of such resources where practicable."

As discussed previously, studies indicate that environmental degradation is still occurring despite the current requirements within the implementing regulations of SMCRA. OSMRE has determined that this research indicates that effective evaluation of trends and impacts on groundwater, surface water, and stream-related resources and biota, would require additional monitoring of data beyond what is currently required by existing regulations. Additional water quality parameters must be monitored both in the baseline condition and within any effluent leaving mine sites. Similarly, existing regulations do not provide for collection of baseline data sufficient to determine the biological condition of streams. Consequently characteristics of the aquatic community in the stream are not well documented in SMCRA permit files. This impedes regulators' ability to assess whether an operation is adequately minimizing adverse impacts on fish, wildlife, and related environmental values, as required by sections 515(b)(24) and 516(b)(11). More complete and accurate baseline information is needed to improve regulators' ability to determine whether mine plans are designed in accordance with the Act, and whether operations are being conducted in accordance with mining plans. For example, better baseline data would facilitate a more thorough cumulative hydrologic impact analysis (CHIA); would help set objective and measurable material damage standards; and would help identify and address hydrologic problems that may arise after permit issuance.

Additional data is also needed to provide sufficient warning when water impacts are approaching thresholds where corrective actions should be taken to prevent further damage. This change would help operators and regulators evaluate the potential for future violations, such as material damage to the hydrologic balance.

Increased frequency of inspection and improved reporting is needed to ensure effective compliance with SMCRA requirements for restoration of approximate original contours (AOC) on the site post-mining. OSMRE has identified a number of instances where the regulatory authority overlooked inadequate contour restoration until late in the process (at which point correcting the problem would be overly expensive or cause unacceptable disruption of stabilized conditions). To address such problems, OSMRE is evaluating alternatives to ensure sufficient reporting and inspection regarding contour restoration.

NEED FOR ADEQUATE OBJECTIVE STANDARDS

In order to effectively implement SMCRA's requirements related to stream protection, regulations must allow permittees and operators, as well as regulatory authorities, to effectively evaluate compliance and limit or prevent adverse impacts, as appropriate.

The regulatory standards must provide an objective threshold with clear and predictable standards for preventing "material damage to the hydrologic balance outside the permit area," as required by section 510(b)(3) of SMCRA. That section requires that each surface coal mining operation be designed to prevent material damage to the hydrologic balance outside the permit area. However, neither OSMRE nor most states have defined this term. A clear Federal definition of "material damage", and Federal minimum standards or criteria against which to measure whether material damage has occurred, is needed to provide a basis for oversight of state implementation of this statutory requirement.

As noted above, based on observed changes, OSMRE believes that existing permitting and performance standards implementing section 515(b)(10) of SMCRA may be inadequate to minimize disturbances to the prevailing hydrologic balance at the mine site and to the quality of water in surface and ground water systems. More specific, more clearly defined and objective standards would ensure implementation of this statutory requirement.

Improved implementation of section 515(b)(3) of SMCRA is also needed. This section requires, with certain exceptions, that mined land be restored to AOC. Restoration of mined land to a surface configuration that includes convex and concave terrain patterns and landforms typical of pre-mining condition could more effectively meet this requirement. The existing rules governing AOC restoration are general, subjective, and lacking in specificity. Too often, this has resulted in postmining surface configurations that are significantly flatter than the premining configuration; that lack many of the landform features found prior to mining; and that have significantly altered drainage patterns and stream characteristics and functions.

NEED TO APPLY CURRENT INFORMATION, TECHNOLOGY, AND METHODOLOGIES

This federal action is also designed to incorporate significant advances in scientific knowledge that has occurred since OSMRE's permanent program regulations were adopted in 1979, and then substantially amended, starting in 1983.

First, new information exists on the adverse impacts that coal mining can cause to water resources and stream biota. As discussed in more detail in Chapter 4, there are many recent publications of studies and literature surveys that evaluate the impacts of surface coal mining and reclamation operations on water quantity and quality, as well as related biological resources.

Second, since OSMRE's earlier rulemakings, there have been many improvements in technologies and methodologies for prediction, prevention, mitigation, and reclamation of coal mining impacts on hydrology, streams, fish, wildlife, and related resources. These advances have included significant improvements in the cost-effectiveness and availability. As discussed in more detail in Chapter 4, OSMRE has identified major improvements in technology and methodology related to identifying, quantifying, mapping, and modeling mining operations and their impacts on the environment. Examples of such improvements are discussed below.

Advances in identification and prediction of impacts on stream resources. Since the 2008 SBZ rule, there have been significant improvements in analysis of the impacts of mining on stream resources. For instance, coal mining-related regulatory programs have traditionally focused on acid mine drainage and sediment loads as the sources of potential problems. As described in Chapter 4 of the SPR DEIS, however, multiple chemical constituents produced by mining cause significant increases in conductivity and total dissolved solids (TDS) in streams below many surface mines, particularly below excess spoil fills. OSMRE has learned that those changes can have significant toxic effects on streams, leading to a loss of sensitive aquatic organisms even when downstream habitats are otherwise intact. Emerging science indicates that problems can include golden alga blooms and adverse impacts to fish and wildlife from the discharge of chemical constituents not considered in past rulemaking efforts. Further, data now indicate that some pollutants, such as selenium, may bio-accumulate. Accumulation of pollutants in biological systems over time may adversely affect biota and human health. In addition new studies indicate that toxic discharges may continue for decades even after reclamation of the site has otherwise been successful according to current requirements for restoration of the land itself.

Similarly, information is now available connecting the life histories of aquatic taxa with stream flow regimes, and this information allows better characterization of streams. For example, taxa requiring a full year of aquatic larval development in highly oxygenated waters would not be expected to be found in ephemeral streams and many intermittent streams.

Landform elements such as ridges, valleys, hill slopes, and streams can now be measured quantitatively in a way not feasible until recently. Permit reviewers can now utilize computers and sophisticated software to process huge amounts of elevation data acquired from stereo satellite and airborne images, LiDAR, and radar to produce much more accurate maps and models of surface configuration than was possible a few short years ago. This information may allow state regulators to determine the total volume of earth that a mining operation has or will displace, based on the position of the coal seams and volume of overburden relative to the premining topography. These data can also be used to plan for restoration of smaller-scale features that blend into the surrounding topography within a watershed. By contrast, reclamation practices under existing regulations often rely on construction of uniformly sized and spaced structures and features

Advances in reclamation techniques. Emerging science now provides much better information on effective reclamation practices related to stream protection. During the last decade, the scientific community has made great strides in developing geomorphic reclamation strategies that reduce erosion and improve water quality. These improvements are not reflected in current regulations. More traditional approaches to restoration of AOC have created large reclaimed acreages that resemble landscapes of agricultural fields, urban recreational parks, or construction fill sites such as large dam embankments, spillways, or waterway diversions. Modern GPS-enabled equipment can incorporate the use of geomorphic principles in reclamation design, and can provide a closer approximation of the highly dissected and randomly spaced and sized drainage patterns of an undisturbed landscape. The Los Angeles abrasion test (a standard test method for determining resistance to degradation) and the sodium or magnesium sulfate soundness test (which distinguishes between rocks based on their susceptibility to weathering) can be used to assess the appropriateness of material used in fills. Hydrologic modeling programs such as the US Army Corps of Engineers Hydrologic Engineering Center, Hydrologic Modeling System (HEC-HMS) can predict with greater accuracy the flow pattern and volume of runoff that would occur under different rainfall scenarios at defined locations. Use of programs such as the by Civil Software Design, LLC Sediment, Erosion, Discharge by Computer Aided Design (SEDCAD) program can more effectively design and evaluate erosion and sediment control systems. Such improvements in reclamation may significantly improve stream restoration and long-term landscape stability.

Advances in reforestation techniques have been shown to decrease the detrimental effects of storm runoff. Science now indicates that high nutrient loads can have negative, cumulative impacts downstream, but that riparian buffer zones can reduce those nutrient loads and associated impacts. OSMRE experience over the past thirty years indicates that extensive herbaceous ground cover on reclaimed areas can inhibit the establishment and growth of trees and shrubs. The dense herbaceous ground covers often used to control erosion compete with newly planted trees and tree seedlings for soil nutrients, water, and sunlight, and provide habitat for rodents and other animals that damage tree seedlings and young trees. Use of the Federal Geographic Data Committee's U.S. National Vegetation Classification Standard, and other generally accepted standards, is needed to promote consistent identification of plant communities and development of appropriate revegetation plans to restore those communities following mining.

1.6 PURPOSE OF THE FEDERAL ACTION

The purpose of this action is to provide a rulemaking that meets the stated purposes of SMCRA (30 U.S.C. § 1202). The rulemaking is intended to improve the ability of coal mine operators, regulatory authorities, and OSMRE to anticipate and prevent adverse impacts to streams and related resources, while ensuring a coal supply adequate for our

Nation's energy needs. In addition, this action seeks to ensure consistent nationwide implementation of SMCRA stream protection requirements, and to appropriately balance all relevant purposes of SMCRA.

1.7 REPORT ORGANIZATION

The remainder of this RIA is organized as follows:

- **Chapter 2** provides an overview of the coal mining industry, market, and regulations influencing current baseline mining practices.
- **Chapter 3** provides an overview of the cost-benefit analysis method.
- **Chapter 4** focuses on the costs associated with activities necessary to achieve compliance with the Proposed Rule.
- **Chapter 5** analyzes the market welfare losses and economic impacts of the Proposed Rule.
- **Chapter 6** presents the results of the regional economic analysis.
- **Chapter 7** analyzes the human health and environmental impacts of the Proposed Rule.
- **Chapter 8** compares the results for the Alternatives and highlights how their impacts will likely differ.
- **Chapter 9** analyzes all other equity considerations and impacts of the Proposed Rule.

CHAPTER 2 | OVERVIEW OF THE COAL MINING INDUSTRY AND COAL MARKET

This chapter provides a brief overview of U.S. coal reserves and coal mining operations. The discussion also characterizes the broader coal mining industry and the current regulations affecting the mining industry. This information is provided as context for the analysis of the likely impacts of the Proposed Rule.

2.1 BACKGROUND ON U.S. COAL RESERVES

This section summarizes coal resources in the U.S. and the mining techniques used in the U.S. coal mining sector. Detailed information can be found in other sources (e.g., Chapter 3.1 of the Proposed Rule EIS and the U.S. Energy Information Administration).

COAL RESOURCES AND RESERVES

The total volume of coal resources in the United States is estimated to be nearly four trillion short tons.[6] However, whether any given component of this reserve is practicably minable and the timing of its extraction will depend on a number of factors. These include the qualities of the reserve (e.g., depth of the coal seam, BTU content, stripping ratio[7]), the price of the coal to be produced, available mining technologies, regulatory and policy constraints, and other factors. Since not all reserves are available (e.g., reserves which lie under metropolitan areas), the Energy Information Administration also considers the demonstrated reserve base (DRB), which is the quantity of coal that could be physically mined under beneficial economic conditions. It is estimated that 483 billion short tons are in the Nation's DRB, or the equivalent of approximately 500 years of continuous domestic consumption at 2012 levels.[8] However, the volume of recoverable reserves is further limited by technological constraints (e.g., coal reserve accessibility by existing mining machinery) and recovery factors (e.g., the amount of coal which can be produced from each seam). The *estimated recoverable reserves* (ERR) are reserves of coal that can be mined with current technology and are estimated based on information reported to the EIA by active, economically viable mines.[9] In 2012, EIA estimated the

[6] U.S. Energy Information Administration (EIA). 2011a. Coal Explained. Accessed 22 August 2011 from: http://www.eia.gov/energyexplained/index.cfm?page=coal_home.

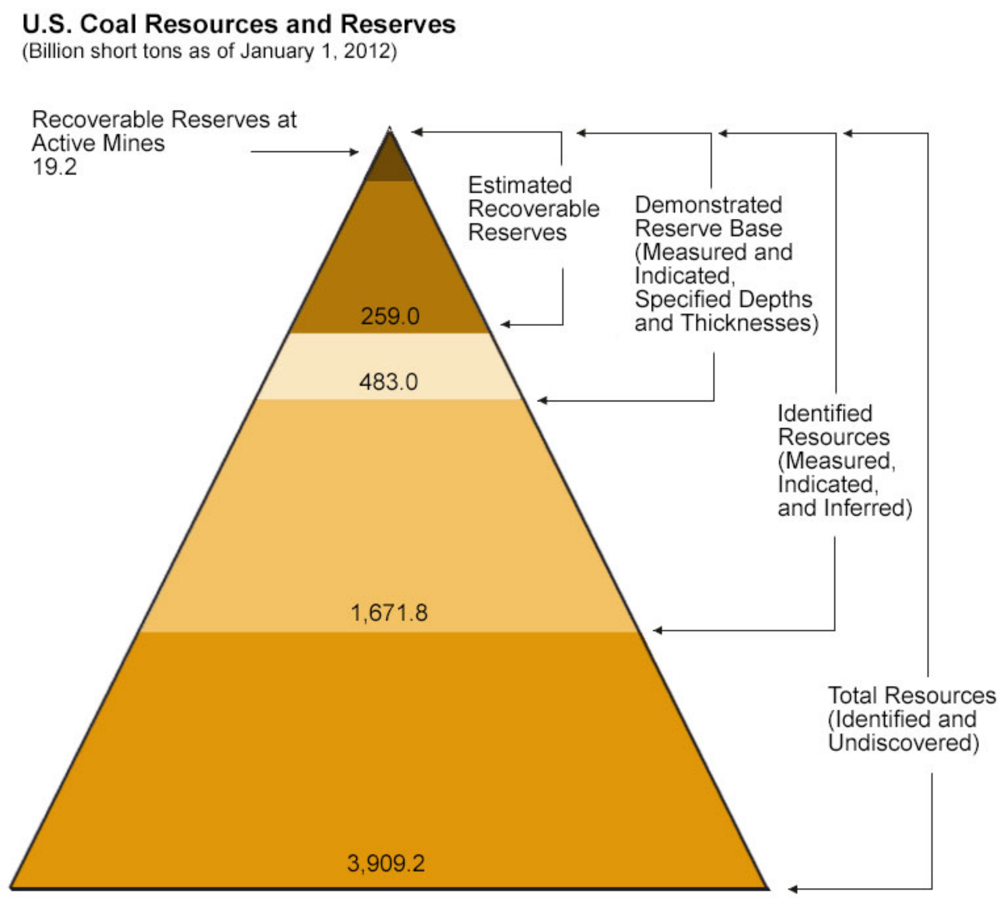
[7] Stripping ratio (also mining ratio) is the ratio of overburden that needs to be removed to the amount of coal produced. Overburden is the top soil and the layers of rock that often rest above coal seams.[11]

[8] U.S. EIA 2011b. Coal Explained: How large are U.S. coal reserves? Accessed on August 21, 2014 at http://www.eia.gov/tools/faqs/faq.cfm?id=70&t=2 .

[9] U.S. EIA. 2011c. Coal Glossary. Accessed November 2011 from: http://www.eia.gov/tools/glossary/index.cfm

ERR to be roughly 258 billion tons, or slightly more than half of the DRB.[10] Recoverable reserves would provide approximately 250 years of demand at 2012 consumption levels.[11] Exhibit 2-1 below summarizes U.S. Coal Resources and Reserves remaining as of January 1, 2012.

EXHIBIT 2-1. U.S. COAL RESOURCES AND RESERVES REMAINING AS OF JANUARY 1, 2012



Source: U.S. Energy Information Administration, *Annual Coal Report 2011* (November 2012).

[10] U.S. EIA 2011b. Coal Explained: How large are U.S. coal reserves? Accessed 21 August 2014 from: http://www.eia.gov/tools/faqs/faq.cfm?id=70&t=2.

[11] Coal reserves are often compared to current annual consumption rates, to provide perspective on the quantities presented. Long-term extraction rates will depend on a range of factors (e.g., development of export markets, changes in energy technology).

Coal reserves are spread across much of the U.S. The largest estimated recoverable reserve base lies in Montana and Illinois.[12]

NATURAL GAS SUPPLY

Long-term trends in coal markets will also depend on developments in natural gas markets. EIA's estimate of proved domestic (wet) natural gas reserves increased to 348.8 trillion cubic feet as of December 31, 2011, with much of the increase driven by shale gas.[13] Increased supply has led to a dramatic decrease in wellhead prices. In the AEO 2013, EIA projects average real growth of 2.4 percent per year in real natural gas prices between 2011 and 2040.[14] To the extent that EIA over- or under-estimates reserves, natural gas prices may deviate from this projected path. Given that coal and natural gas are substitutes in the production of electricity (and in industrial boilers), changes in natural gas markets can impact coal markets.

TYPES OF COAL

The type and characteristics of coal available in any given region can vary. Coal can be classified into four main types, listed below from highest to lowest heating value (Btu per short ton):

- Anthracite. Anthracite deposits are estimated to be more than 200 to 300 million years old, and contain 86 to 97 percent carbon. The heating value for anthracite coal is approximately 24 million to 28 million Btu/ton.[15] Anthracite is the least abundant coal type in the U.S., with production concentrated in northeastern Pennsylvania. Only about 1.5 percent of the Nation's DRB and 0.5 percent of coal produced is anthracite.[16] Anthracite's high heating value commands the highest prices of raw coal per ton, with average market prices in 2012 of $80.21 (per ton).[17]

- Bituminous. Bituminous coal reserves are estimated to be 100 to 300 million years old, and contain 45 to 86 percent carbon. Bituminous heating values are estimated to be between 21 million to 28 million Btu/ton.[18] Bituminous coal

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[12] U.S. EIA. 2012a. Annual Energy Review 2011. U.S. Department of Energy. Table 4.8: Coal Demonstrated Reserve Base, January 1, 2011 (Billion Short Tons). Accessed from: http://www.eia.gov/totalenergy/data/annual/archive/038411.pdf

[13] U.S. EIA. 2014a. U.S. Crude Oil and Natural Gas Proved Reserves, 2012. Accessed August 2014 from: http://www.eia.gov/naturalgas/crudeoilreserves/?src=Natural-

[14] U.S. EIA. 2013b. Annual Energy Outlook 2013. U.S. Department of Energy, Office of Integrated and International Energy Analysis.

[15] U.S. Environmental Protection Agency (EPA). 1996a. Anthracite Coal Combustion. Accessed September 2014 from: http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s02.pdf

[16] U.S. Energy Information Administration (EIA). 2011a. Coal Explained. Accessed 22 August 2011 from: http://www.eia.gov/energyexplained/index.cfm?page=coal_home.

[17] U.S. EIA. 2013c. Annual Coal Report: Table 31. Average Sales Price of Coal by Coal Rank, 2012. Accessed 08 July 2014 from: http://www.eia.gov/coal/data.cfm#prices

[18] U.S. EPA. 1996b. Bituminous and Sub-bituminous Coal Combustion. Accessed September 2014 from: http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s01.pdf

makes up nearly 53 percent of the DRB and more than 45 percent of the coal mined.[19] It is primarily mined in areas east of the Mississippi River, such as Illinois, Kentucky, and West Virginia. Bituminous coal includes the majority of metallurgical coal currently produced in the U.S.[20, 21] Average prices in 2012 for Bituminous coals were approximately $66.04 per ton.[22]

- Subbituminous. The U.S. subbituminous coal reserves are estimated to be more than 100 million years old, and contain 35 to 45 percent carbon. The heating value of subbituminous coal is estimated to be between 16 million and 23 million Btu/ton.[23] Subbituminous coal accounts for nearly 37 percent of the DRB. Primarily found in Wyoming and Montana, subbituminous coal is the most abundant coal produced in the U.S., accounting for about 40 percent of the Nation's production in 2012.[24] The relative abundance of these subbituminous coals make them a relatively cheaper coal to purchase, averaging $15.34 per ton in 2012.[25]

- Lignite. Lignite a crumbly and moisture-rich coal with the lowest heating value. It is the youngest of the coal types, with 25 to 35 percent carbon content. As a result of its characteristics, lignite has a relatively low heating value, between 10 million and 15 million Btu/ton.[26] Lignite makes up approximately nine percent of the DRB. This coal type is primarily found in the U.S. Gulf (i.e., Texas, Mississippi, and Louisiana), and the Great Plains (i.e., Montana and North Dakota) and constitutes approximately 7.5 percent of U.S. coal production in 2012. Average prices for lignite in 2012 were $19.60 per ton.[27]

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[19] U.S. Energy Information Administration (EIA). 2011a. Coal Explained. Accessed 22 August 2011 from: http://www.eia.gov/energyexplained/index.cfm?page=coal_home; U.S. EIA 2011b. Coal Explained: How large are U.S. coal reserves? Accessed on August 21, 2014 at http://www.eia.gov/tools/faqs/faq.cfm?id=70&t=2 .

[20] U.S. EIA. 2011d. Coal Prices: Met Coal 2011. Accessed October 2011 from: http://www.eia.gov/coal/news_markets/chartdata/coal_price.csv

[21] Declared export prices differ from market prices in that declared export prices are net of any transport costs or taxes. These prices are prices declared at the port of origin.

[22] U.S. EIA. 2013a. Annual Coal Report 2012. U.S. Department of Energy. Table 31. Average Sales Price of Coal by Coal Rank, 2012. Accessed 08 July 2014 from: http://www.eia.gov/coal/data.cfm#prices

[23] U.S. EPA. 1996b. Bituminous and Sub-bituminous Coal Combustion. Accessed September 2014 from: http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s01.pdf

[24] U.S. Energy Information Administration (EIA). 2011a. Coal Explained. Accessed 22 August 2011 from: http://www.eia.gov/energyexplained/index.cfm?page=coal_home.

[25] U.S. EIA. 2013a. Annual Coal Report 2012. U.S. Department of Energy. Table 31. Average Sales Price of Coal by Coal Rank, 2012. Accessed 08 July 2014 from: http://www.eia.gov/coal/data.cfm#prices

[26] U.S. EPA. 1996c. Lignite Combustion. Accessed September 2014 from: http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s07.pdf

[27] U.S. EIA. 2013a. Annual Coal Report 2012. U.S. Department of Energy. Table 31. Average Sales Price of Coal by Coal Rank, 2012. Accessed 08 July 2014 from: http://www.eia.gov/coal/data.cfm#prices

2.2 THE PROCESS OF MINING COAL

This section provides basic information about coal mining technologies. This information is drawn from Chapter 3.1 of the Proposed Rule EIS, where additional detail is provided.

MINE TYPES

Surface Mining

Broadly speaking, there are two methods for mining coal: surface and underground mining. In 2012, surface mines provided about two-thirds of domestic total production. Whether a coal reserve can be feasibly mined using surface mining technologies depends on its geology, as well as regulatory and other constraints.

Surface mines use large machines, such as draglines and large shovel loaders, to remove the layers of soil and rock that make up the overburden to expose coal seams. These operations can occur at depths of up to 200 feet depending upon the thickness of the seam. Secondary techniques, known collectively as highwall mining, are also used after economic limits to overburden removal are reached to extract additional minable coal. Surface mining can further be broken into contour mining, open pit mining, and area mining, as discussed in Exhibit 2-2.

EXHIBIT 2-2. SURFACE MINE TYPES

TYPE	CHARACTERISTICS
Contour	• Used primarily along mountainsides and at the end of ridgelines • Cut toward center of mountain • Removes overburden and exposes available coal seams for extraction • Reclamation generally done in conjunction with extraction operations
Open Pit	• Occurs in areas of limited topographies and relatively thick coal seams (which reduces stripping ratios) • Removes overburden to expose coal seams for extraction • Returns overburden to the pit after seam is excavated
Area	• Suitable for locations with multiple coal seams and varied terrain • Strip mining utilizes draglines and/or trucks and shovel loaders and is the primary surface mining method in the Northern Rocky Mountain/Great Plains, Illinois Basin, Colorado Plateau, Western Interior and Gulf Coast regions • Overburden expands after removal and in mountainous locations involves placement of excess spoils in nearby valleys or in designated refuse areas • Iterative process: remove overburden, mine seams, backfill previously mined areas • Mountaintop removal (MTR) is a subset of area mining[28] • Recovery rates (amount of coal extracted per labor hour) are high compared to other forms of surface mining, upwards of 70-80 percent due to the large-scale operation

[28] U.S. EPA. 2003. Mountaintop Removal/Valley Fill DEIS. Accessed July 2011 from: http://www.scdhec.gov/environment/baq/docs/SanteeCooper/Comments/psd_SELC_attachment.07.pdf

TYPE	CHARACTERISTICS
Highwall	• Used to extract additional mineable coal in pit, contour, and area mines • Extract coal within the "highwalls" surrounding surface pits or area mines • Mechanical drivers push continuous mining cutter or an auger into the exposed mountainside coal seam • Allows coals that would otherwise be left unmined due to economic costs of overburden removal to be mined
Sources: U.S. EPA, 2003; EIA, 2011c.	

Underground Mining

Underground mining, or deep mining, is used to extract coal from seams hundreds of feet below the ground. Compared to surface mines, underground mines require considerably more safety and health infrastructure such as ventilation, water, lighting, and physical support infrastructure. Underground coal seams are accessed through a number of different mining techniques, including drift mining, box cut mining, slope/slant mining, and shaft mining, as shown in Exhibit 2-3.

EXHIBIT 2-3. UNDERGROUND MINE OPENING TYPES

TYPE	CHARACTERISTICS
Drift	• Enters coal seam horizontally from an exposed section on a mountainside or sloped area • Considered simplest and most economical mine type • Follow the seam (drifting) into the mountainside, then construct room and pillars to mine
Box cut	• Removes overburden to expose coal seam and follows underground beyond the highwalls created • Similar to highwall mining in surface mining but excavates further into the mountainside • Similar room and pillar or longwall techniques are employed underground
Slope/Slant	• Used to access coal outcrops that are not directly accessible but are at an economical depth • Tunnel through overburden at an angle to access coal deposits • Uses conveyors to remove coal • Similar room and pillar or longwall techniques are employed underground
Shaft	• Used for coal seams that are relatively deep or cannot be accessed by surface techniques due to property or topographical limitations • Hoist elevator transports equipment and workers through vertical shaft • Coal carried in hoist cars and vertical conveyors
Sources: U.S. EPA, 2003; EIA, 2011c.	

MINING TECHNIQUES

As noted above, techniques utilized for extraction of the coal vary depending on the age and depth of the coal seam as well as other characteristics of surrounding geology. Underground mines generally use room and pillar and longwall techniques using continuous miners, shears, and automated conveyors.[29]

Room and Pillar Mining

Room and pillar mines are created by making a parallel series of entries into a seam with perpendicular crosscuts that connect the entries to form a grid-like pattern in the coal. This mining method allows operators to strategically choose areas of high coal quality first, utilizing the remaining blocks of coal as pillars to prevent the “roof” of the mine from collapsing. Each pillar can range in size from 20 to 90 feet on a side, depending on the geology in which the mine is operating.[30]

There are two types of room and pillar mining: conventional and continuous. Conventional techniques generally employ mechanical cutting machines and may include compressed air to facilitate coal removal. Continuous room and pillar mining utilizes machinery to continuously cut into the mine face and mechanically break the coal while simultaneously loading it onto haulage equipment to be taken away. This method does not rely heavily on explosives and differs from conventional techniques by continually mining without pause. Continuous mining techniques are typically less labor intensive, but can be less flexible in responding to variations in coal quality and other operational geologic impediments (e.g., in the event coal seam continuity changes drastically or recovery rates change). After primary extraction of the seam has been completed, the continuous mining machine direction can be reversed for secondary or retreat mining. Conventional techniques limit the extent to which retreat mining can occur.

High Extraction/Retreat Mining

In retreat mining, also known as “high extraction” mining, some coal pillars are systematically removed to maximize the recovered coal from a room and pillar mine. During secondary extraction, roof collapse and subsidence (collapse of surface lands above underground mines) can occur as the roof supports are removed. The amount of coal that can be retrieved from retreat mining depends on a number of factors, including safety and geological considerations. Mines that engage in both primary and secondary mining extract upwards of 80 percent of the coal in the seam being mined.

Longwall Mining

Longwall mining utilizes heavy machinery and hydraulic lifts to mine coal underground while preventing roof collapse. Cuts are made into the coal seam much like under the room and pillar method, but a cross heading is made separating the coal into minable “panels”. A shearer (or cutter drum), mounted to a track, is set up to mine cross sections

[29] Darmstadter, J. and Krop, B. 1997. Productivity Change in U.S. Coal Mining. Resources for the Future. Accessed 22 August 2011 from: http://www.rff.org/RFF/Documents/RFF-DP-97-40.pdf

[30] Ibid.

of the panel. A haulage system is attached to the track to remove coal from the mine. Once the shearer reaches the end of its track, the machine reverses its course, taking iterative cross-sections of the panel. Hydraulic supports called "shields" are used to keep the roof of the panel from collapsing until the mining is complete. Shields advance as the coal is removed allowing the roof to collapse in a predictable manner. As a result, the surface subsidence above the mine occurs within a defined timeframe. Longwall panel sizes, which have increased over time, are generally large, averaging approximately 1,000 feet wide by 10,000 feet long.[31] Longwall mining operations are best suited to areas with coal reserves greater than six feet in thickness and regular in shape for the hydraulic supports to function.[32] Since initial capital investments in longwall mines are high, these operations generally require mineable reserves greater than 50 million tons to make the operation financially viable.[33]

PERMITTING AND BONDING

Permit Application

Under SMCRA, operators apply for mining permits from OSM; in states with primacy, operators apply for permits from the relevant State Regulatory Authority (SRA). Submission of a detailed application form commences the application process. As part of the application, the operator must describe such things as the characteristics of the affected land and its ecology, plans for proposed mining and reclamation operations, the operator's legal status, the mining entity's financial history, and the entity's history of compliance with the various laws and regulatory requirements for coal mining. Based on the information submitted, an operator must show the ability to: (1) meet all requirements of SMCRA; and (2) successfully reclaim the land in compliance with the standards in SMCRA and subsequent regulations. The specific regulations governing approval of SMCRA permits are being revised as part of the current Proposed Rule. In addition, permits may be required under the Clean Water Act and other authorities.

After receiving the permit application, the SRA determines whether the application is administratively complete. If complete, a public comment period begins, where announcements are made in local newspapers and documents are released for public viewing. Simultaneously, OSMRE or the SRA will begin an internal application review. After correcting any application deficiencies and addressing public and agency concerns, permits can be approved and mining operations begun.

Performance Bonding

Prior to receiving a permit to mine, operators must set aside funds in the form of a bond to: (1) provide collateral to ensure reclamation occurs to regulatory specification; and (2) complete reclamation by the regulatory authority in the event reclamation is not completed. After reclamation is successfully completed, these bonds are returned to the

[31] Ibid.

[32] Ibid.

[33] Ibid.

operator. This typically occurs in three stages, with portions of the bond being released as reclamation efforts progress;

- Phase I bond release requires backfilling, regrading, and drainage control of the affected lands to stipulations outlined in the original permit contract.
- Phase II bond release requires replacement of salvaged topsoil and the establishment of revegetation on affected areas.
- Phase III bond release requires demonstration of successful revegetation of the affected area, as well as completion of all other reclamation requirements.[34]

Permit Life

SMCRA mining permits have five-year terms with an opportunity for renewal if requested at least 120 days prior to the expiration of the preceding permit.[35] Depending on a number of mine-specific factors, including approximate life of a mine, coal quality, and stripping ratio, a mine may acquire numerous permits over its operating life

2.3 OVERVIEW OF COAL MINING ACTIVITY IN THE U.S.

In 2012, 25 states reported active coal mine production to MSHA.[36] OSMRE classifies coal-producing areas into regions, seven of which produced coal in 2012, as shown in Exhibit 2-4. These regions are described below, and organized from largest volume of production to least production in 2012:

- **Northern Rocky Mountain and Great Plains** (including the Powder River Basin): Wyoming, Montana, Eastern Colorado, North Dakota, South Dakota[37]
- **Appalachian Basin**: West Virginia, Eastern Kentucky, Pennsylvania, Ohio, Virginia, Alabama, Tennessee, Maryland
- **Illinois Basin**: Illinois, Indiana, Western Kentucky
- **Colorado Plateau**: Western Colorado, New Mexico, Utah, Arizona
- **Gulf Coast**: Texas, Mississippi, Louisiana
- **Northwest**: Alaska, Washington[38]
- **Western Interior**: Oklahoma, Missouri, Kansas, Arkansas

[34] U.S. Office of Surface Mining Reclamation and Enforcement (OSMRE). 2011. Bonds Overview. Accessed 09 September 2011 from: http://www.osmre.gov/topic/bonds/BondsOverview.shtm

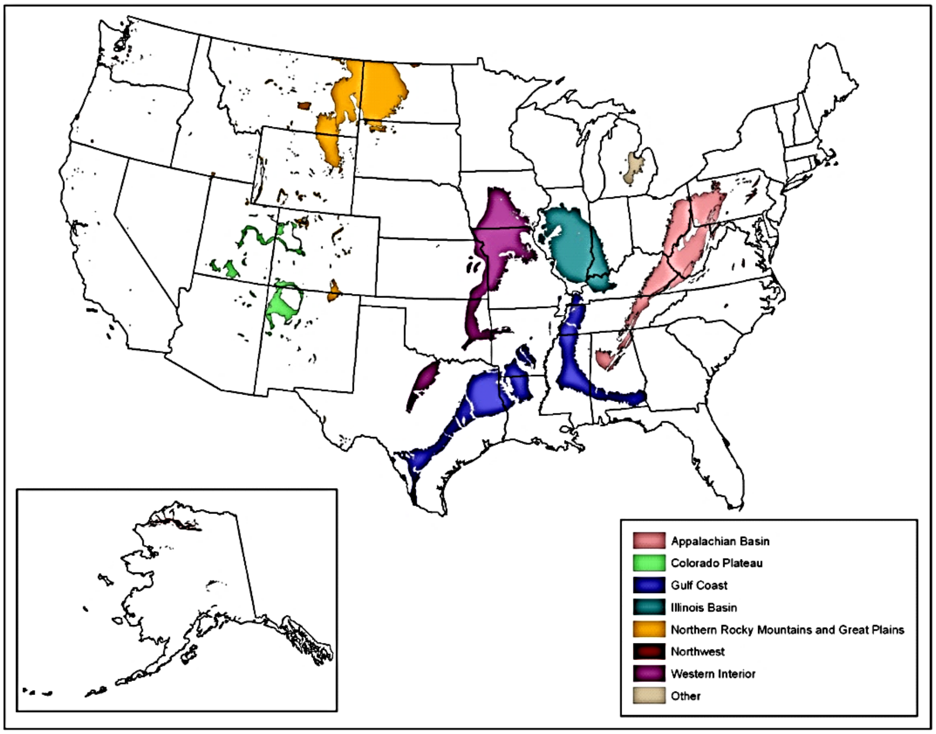
[35] 30 CFR § 1256 (b) and (d)

[36] MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013.

[37] South Dakota is included in the Northern Rocky Mountain and Great Plains region but did not produce any coal in 2012.

[38] Washington is included in the Northwest region but did not produce any coal in 2013.

EXHIBIT 2-4. POTENTIALLY MINABLE COAL FIELDS IN THE U.S.

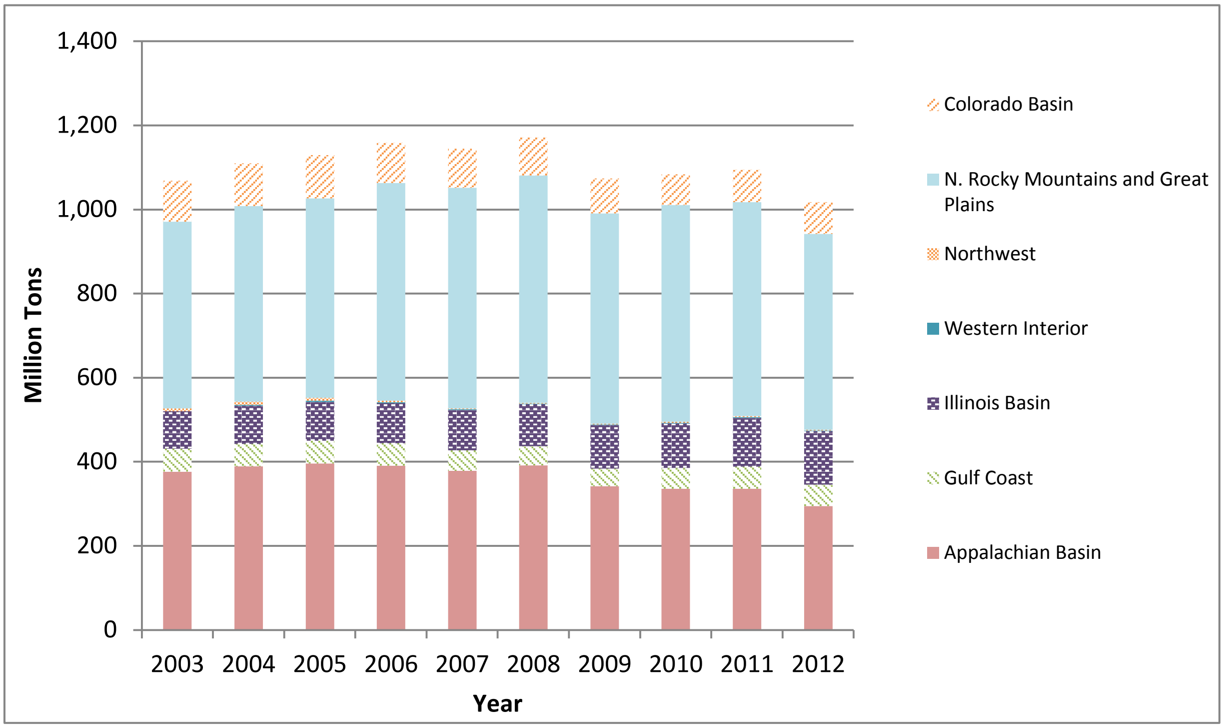


Source: USGS. 2001. National Atlas of the United States: Coal Fields of the United States. U.S. Department of the Interior.

As shown in Exhibit 2-5, total U.S. coal production has fluctuated somewhat over time, with production from particular regions varying to a greater degree. Total production in 2012 was 1,016 million tons, or nine percent less than production in 1998.[39] Since 1998, the two primary coal production regions in the U.S. have been the Northern Rocky Mountain/Great Plains, and the Appalachian Basin. In 2012, these two regions together accounted for approximately 75 percent of domestic coal production.

[39] MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013.

EXHIBIT 2-5. TOTAL COAL PRODUCTION AND COAL PRODUCTION BY REGION, MILLION TONS (1998-2012)



Source: MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013; and EVA analysis, 2012.

The size of a typical mine varies by region. As shown in Exhibit 2-6, average production per surface mine in the Appalachian Region in 2012 was approximately 157,000 tons, as compared to about 17.5 million tons from the average Northern Rocky Mountain/Great Plains region mine. The largest mines in the U.S. during 2012 were found in the Northern Rocky Mountain (Powder River Basin)/Great Plains Region, with the Northern Antelope Rochelle mine which produced over 107 million tons and the Black Thunder mine which produced over 93 million tons.[40]

In 2012, over 1,063 mines reported coal production to the Mine Safety and Health Administration (MSHA).[41] Although the mines in Appalachia have relatively small average production levels, by far the largest number of mines are found in that region, as shown in Exhibit 2-7.[42] In fact, of the over 1,063 actively producing surface mines and underground mines operating in 2012, over 1,000 were located in Appalachia. In contrast, the Northwest Region had only one producing mine in 2012.

[40] U.S. EIA. 2010a. EIA Annual Coal Production Report 2009.

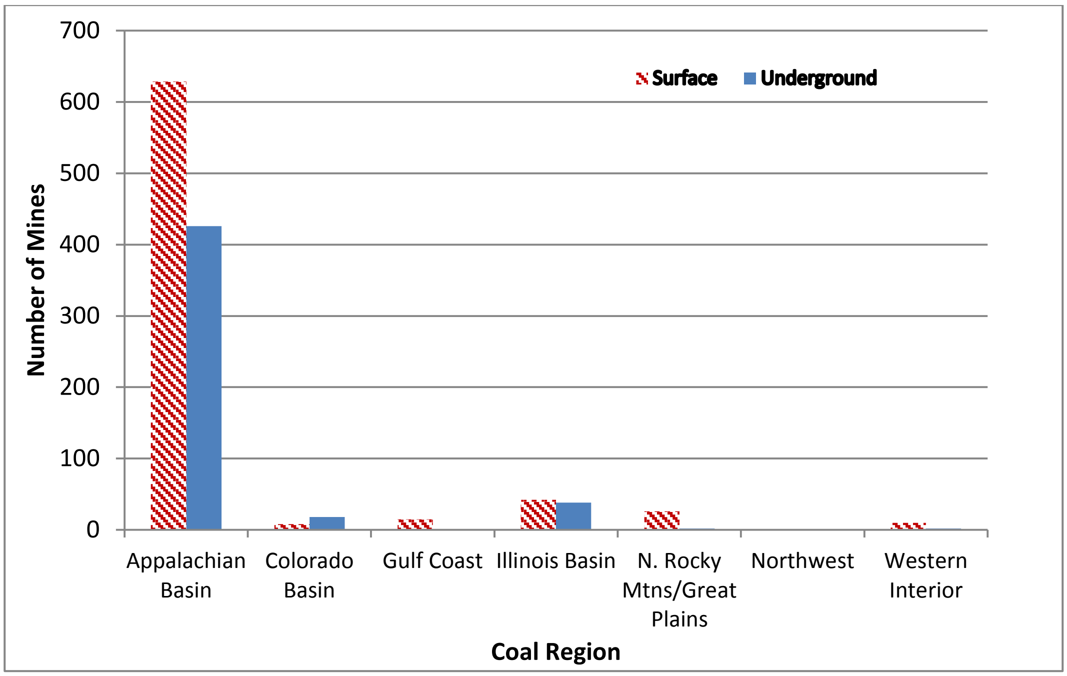
[41] MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013.

[42] Ibid.

EXHIBIT 2-6. AVERAGE PRODUCTION PER MINE BY REGION, MILLION TONS (2012)

REGION	SURFACE	UNDERGROUND
Appalachian Basin	0.1	0.5
Colorado Plateau	3.8	2.5
Gulf Coast	3.4	n/a
Illinois Basin	0.8	2.4
Northern Rocky Mountain and Great Plains	17.5	5.2
Northwest	2.0	n/a
Western Interior	0.1	0.2
Source: MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013; and EVA analysis, 2012		

EXHIBIT 2-7. NUMBER OF COAL MINES BY REGION, 2012



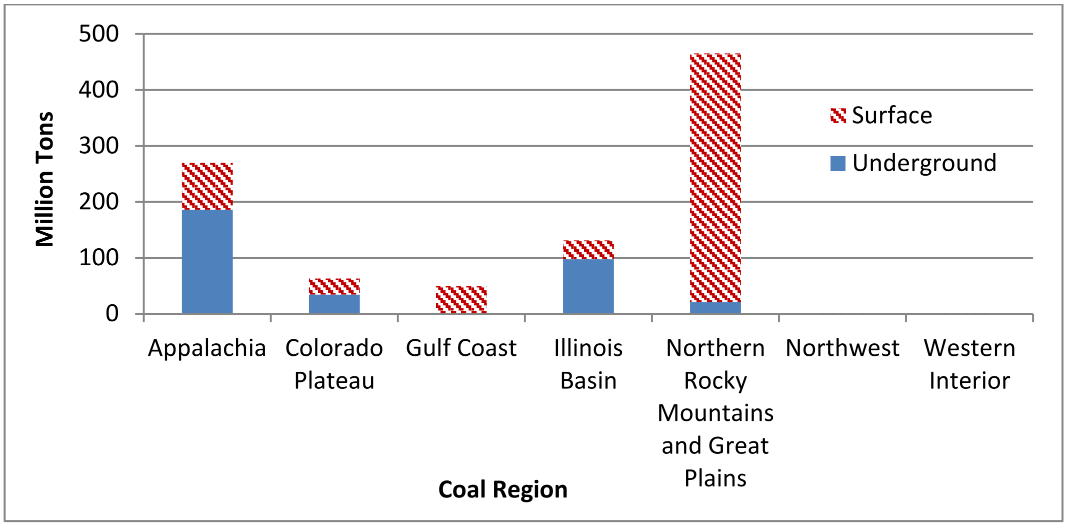
Source: MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013; EVA analysis, 2012.

All regions utilize surface mining techniques, but not all regions have underground mines. The Gulf Coast and the Northwest have no underground mines. Over the past 14 years, the mining industry has shifted production towards surface mining, with surface mining comprising 66 percent of U.S. coal production in 2012, versus 62 percent in 1998.[43] This is largely due to an increase in the number of very large surface mines in the Powder River Basin (Northern Rocky Mountain Region). However, over the next 20

[43] U.S. EIA. 2013a. Annual Coal Report 2012. U.S. Department of Energy. Accessed from: http://www.eia.gov/coal/annual/archive/05842012.pdf; U.S. EIA. 2011e. Annual Coal Mine Production Data, 1998. Accessed July 2011 from: http://www.eia.gov/coal/data.cfm

years, forecasts predict an increase in the relative production of underground mining (see Appendix F). Annual production by type of mine also varies across regions. As shown in Exhibit 2-8, total production volume and production volume by mine type varies across the regions. The Northern Rocky Mountain/Great Plains Region produces coal primarily from surface mines, whereas the Colorado Basin produces the majority of its coal from underground sources.

EXHIBIT 2-8. COAL PRODUCTION BY MINE TYPE BY REGION, MILLION TONS (2012)



Source: MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013.

The coal mining industry is expected to continue to change, even under baseline conditions (i.e., absent the Proposed Rule). These changes will be driven by market conditions and the characteristics of remaining coal reserves. For example, underground production is expected to grow at a faster rate because of the addition of several new longwall mines. The rate at which this happens will depend on market conditions for coal. Production in Appalachia is also expected to shift underground, particularly in the central part of Appalachia, as a greater percentage of production moves into the metallurgical coal (met coal) market which largely comes from underground mining operations. For information on employment in the coal mining industry, see Chapter 6.

CONSOLIDATION AND DIVERSIFICATION

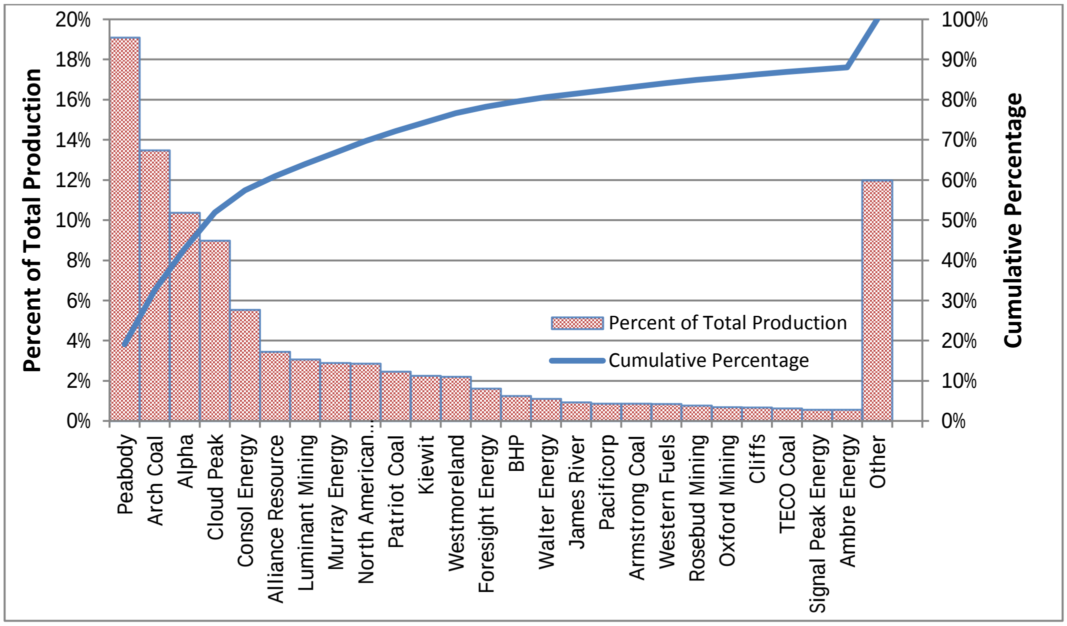
As stated above, production was reported for over 1,100 separate mines to MSHA.[44] While coal production and employment are reported for each mine, most companies operate multiple mines. Overall, the most productive 25 corporations produced more than 88 percent of annual coal production in the U.S. in 2012.[45,46] The top 10 producers

[44] MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013.

[45] All percentages are based upon tons of coal mined.

produced over 72 percent of total production in 2012.[47] In 2012, Peabody Energy Corporation was the largest producer in the U.S, and was responsible for 19 percent of all coal production in the U.S.[48]

EXHIBIT 2-9. CUMULATIVE PERCENTAGE AND PERCENT OF TOTAL PRODUCTION BY CONTROLLING COMPANY, 2012



Source: MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013.

Consolidation has been a trend in recent years within the coal industry.[49] Major consolidations include Alpha Coal's purchase of Massey Energy and Arch Coal's purchase of ICG. Additional consolidation is possible, particularly in regions with declining production.

Another trend has been the growth in export terminal capacity. In the U.S. Gulf, Foresight Energy, through its affiliate Raven Energy LLC purchased the IC RailMarine Terminal Co. from Canadian National Railway Co. (CN) to handle coal exports and Trafigura acquired Ormet's closed Burnside Terminal in Burnside, Louisiana to develop into a bulk export terminal. A number of coal terminals have been proposed for the Pacific Northwest, including SSA Marine's Gateway Pacific Terminal; the Millennium Bulk Terminals, which is a joint venture between Ambre Energy Ltd. and Arch Coal Inc.; and the Morrow Pacific Terminal being developed by Ambre. These terminals are in the process of being permitted. Terminals in British Columbia, exports through the Great

[46] MSHA. 2012. MSHA Annual Coal Production Data 2012. Provided by OSMRE April 15, 2013; and EVA analysis, 2012.

[47] Ibid.

[48] Ibid.

[49] See Appendix B which discusses market forces in more detail.

Lakes, and exports through the U.S. Gulf involve higher transportation costs; therefore, one or more additional terminals in the Pacific Northwest are likely required to handle the projected export levels.

Across the industry, the export market shows signs of expansion, as detailed in the last two *Annual Energy Outlooks (AEO 2012 and 2013)* by the EIA. In 2012, total exports of coal exceeded 125 million tons, with projections for further growth to 159 million tons by 2040.[50] Our forecast domestic production over the timeframe for this analysis is presented in Appendix F. Whether exports will rise by this amount, or by a greater amount, depends largely on world market conditions, as well as the development of port capacity in the Pacific Northwest. This is discussed further below.

2.4 MARKET FACTORS THAT INFLUENCE COAL PRODUCTION

The volume of coal produced in the U.S. in a given year is contingent on a number of market factors. In particular, the international and domestic demand for coal of various qualities, the relative price of natural gas, the U.S. exchange rate, the abundance of recoverable reserves, as well as environmental, health and safety regulations all affect either the demand for or the price of coal, which in turn influences the volume of coal produced.

DOMESTIC AND INTERNATIONAL DEMAND

In 2012, 37 percent of all electric power generated in the U.S. was derived from coal.[51] This was the first time in over a half century that coal's share fell below 40 percent. The primary reason for the low level of coal generation in 2012 was the dramatic decline in natural gas prices during the year, which resulted in natural gas-fired combined cycle capacity dispatching ahead of coal in many parts of the country. Electric power generation remained the most important market for domestic coal, however, accounting for about 90 percent of U.S. coal production in 2012.[52]

Economic and regulatory factors determine the portfolio of electricity generation (i.e., coal, natural gas, nuclear, renewables, or other energy sources). According to the AEO 2013, U.S. electricity energy demand is expected to grow at a 0.9 percent annual rate through 2040.[53] At the beginning of 2012, EIA reported 1,387 coal power plants with a capacity of 317,469 MW.[54] Given the dominant role electricity production plays in coal

[50] U.S. EIA. 2012b. Annual Energy Outlook 2012 Early Release Overview. Accessed January 2012 from: http://www.eia.gov/forecasts/aeo/er/

[51] U.S. EIA. 2011a. Coal Explained. Accessed 22 August 2011 from: http://www.eia.gov/energyexplained/index.cfm?page=coal_home.

[52] U.S. EIA. 2014b. Monthly Energy Review August 2014. U.S. Department of Energy, Office of Energy Statistics.

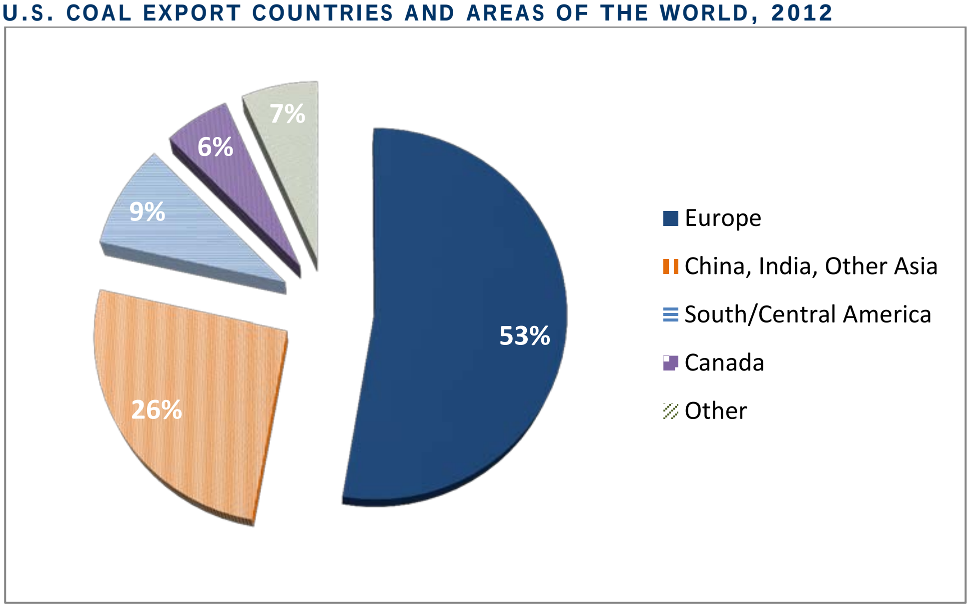
[53] U.S. EIA. 2013b. Annual Energy Outlook 2013. U.S. Department of Energy, Office of Integrated and International Energy Analysis.

[54] U.S. EIA. 2012c. Today in Energy: 27 gigawatts of coal-fired capacity to retire over next five years. Accessed from: http://www.eia.gov/todayinenergy/detail.cfm?id=7290

markets, even small changes in the electricity market can influence both short and long-term demand for domestic coal.

In addition to domestic demand, as noted above, recent increases in export demand for coal have provided a market outlet for domestic producers. In 2012, U.S. coal exports accounted for about 12 percent of U.S. coal production.[55] The breakdown of export markets is provided in Exhibit 2-10.

EXHIBIT 2-10. U.S. COAL EXPORT COUNTRIES AND AREAS OF THE WORLD, 2012



Source: U.S. EIA.2013e. 2013 Coal Imports, Exports, and Distribution. *http://www.eia.gov/coal/data.cfm*

Industrializing nations, such as China and India, are increasing their imports of energy, including coal. In 2012, China is reported to have imported over 250 million short tons of coal, and India over 170 million short tons.[56]

The imported coal is used both in the generation of electricity and their respective domestic industries, such as steel, iron, and cement. Thus, fluctuations in these markets can also cause changes in coal demand. Steel production relies on metallurgical coal, known as "met coal," which is derived from low-sulfur bituminous coals that are largely produced in the Appalachian Basin. This coal is used to make metallurgical coke which is a feedstock for the blast furnace, or in direct coal injection into blast furnaces.[57] About

[55] U.S. EIA. 2013a. Annual Coal Report 2012. U.S. Department of Energy. Table 8: Coal Disposition by State, 2012. Accessed from: http://www.eia.gov/coal/annual/archive/05842012.pdf

[56] Simpson Spence Young (SSY). 2012. Monthly Shipping Review. http://www.ssyonline.com/

[57] For more information about blast furnace technique, see: U.S. Department of Energy. 2000. Blast Furnace Granulated Coal Injection System Demonstration Project: A DOE Assessment. Accessed November 2011 from: http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/bstel/bethstl.pdf

60 million of China's 250 million tons of coal imports were met.[58] The pricing for met coal is typically higher than for steam (or thermal) coal with a quarterly benchmark for hard coking coal established between Australian exporters and the Japanese Steel Mills. The benchmark price has been relatively volatile but is currently about $150 per metric ton.[59]

Sub-bituminous coal is abundant in thick seams at relatively shallow depths on the western plains, and the mining industry in that region benefits from a relatively flat topographical landscape that makes for relative ease of recovery.[60] While international demand for this coal exists, U.S. exports have been limited by transportation constraints. As noted above, a number of pending proposals to build infrastructure in the Northwest could bring an increase in exports of sub-bituminous coal. Our market models and future coal transportation costs are detailed in Chapter 5 and Appendix F.

U.S. EXCHANGE RATE

Seaborne coal trade is U.S. dollar-denominated. As a result, the relative strength of the U.S. dollar is a significant factor in whether U.S. coals are competitive. The primary relationship of concern is between the U.S. dollar and the Australian dollar, as Australia is the largest exporter of metallurgical coals and a significant exporter of thermal coal. As a result, the Australian/U.S. Dollar exchange rate (AUD/USD) plays an important role in coal exports. As shown in Exhibit 2-11, U.S. coal exports have been inversely related to the strength of the Australian dollar in recent years. For example, the relative strength of the Australian dollar after 2006 (lower USD/AUD Exchange ratio) was related to an increase in U.S coal exports.

ABUNDANCE OF RECOVERABLE RESERVES

Production and price are determined by both demand and production costs. Supply generally is not an issue, given abundant coal reserves.

The cost of compliance with regulations, both for the coal mining industry and for firms within their largest markets, will influence the volume of coal that is produced in the U.S. as well as its price. The following chapter describes current and pending regulatory factors that could influence the domestic coal industry.

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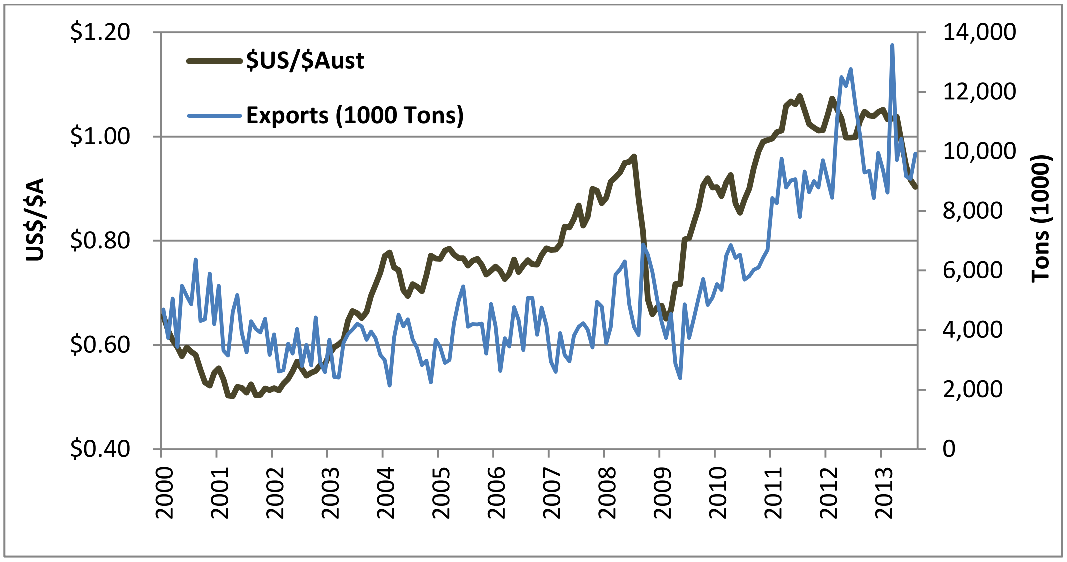
[58] Simpson Spence Young (SSY). 2012. Monthly Shipping Review. http://www.ssyonline.com/

[59] U.S. EIA. 2010b. Coking Coal Prices for Industry for Selected Countries. Accessed from: http://www.eia.gov/countries/prices/cokeprice_industry.cfm; Behrmann, E. 2011. Coking Coal Price to Fall on Softer Demand, Mackenzie Says. Bloomberg Businessweek. Accessed 21 April 2015 from: http://www.bloomberg.com/news/articles/2011-10-19/coking-coal-price-to-fall-on-softer-demand-mackenzie-says-1-

[60] U.S. EIA. 2011a. Coal Explained. Accessed 22 August 2011 from: http://www.eia.gov/energyexplained/index.cfm?page=coal_home.

EXHIBIT 2-11. USD/AUD EXCHANGE RATE AND TOTAL EXPORTED U.S. COAL (2000 - 2013)



Sources: U.S. EIA. 2012a. Annual Energy Review 2011. U.S. Department of Energy. Table 7.5: Coal Exports by Country of Destination, 1960-2011 (Million Short Tons). Accessed from: http://www.eia.gov/totalenergy/data/annual/archive/038411.pdf;

Exchange Rate data: U.S. Federal Reserve. 2013. U.S. / Australia Foreign Exchange Rate. Accessed from: http://research.stlouisfed.org/fred2/categories/95

CHAPTER 3 | APPROACH TO REGULATORY IMPACT ANALYSIS

3.1 INTRODUCTION

The Proposed Rule has numerous potential impacts, including: increased administrative costs to the coal mining industry as well as to state and Federal regulators; increased operational costs for coal mining entities; the "stranding" of coal reserves in areas where it may no longer be viable to mine under the new rules[61]; shifts in the geographic distribution of coal production due to changes in the relative cost of coal production; changes in the total quantity of coal produced; and subsequent changes in the cost of producing electricity. The rule may also generate economic benefits by reducing the environmental and human health impacts associated with coal mining. This RIA examines these potential impacts.

Specifically, this analysis estimates the incremental costs and benefits anticipated to result from the Proposed Rule (i.e., the changes in costs and benefits expected due to this rule over and above the baseline). In this chapter, we present an overview of our approach to the analysis of the rule (including a discussion of how the baseline for this analysis is determined), a discussion of the data sources we rely upon, and a description of uncertainties and limitations to the analysis.

3.2 OVERVIEW OF ANALYTIC APPROACH

The primary steps we undertake in developing this analysis include the following:

- **Defining the baseline conditions:** The first step involves estimating current and expected future conditions in the absence of the rule. The baseline includes the existing regulatory and socioeconomic burden imposed on regulated entities potentially affected by the Proposed Rule; the factors that will impact demand for coal absent this rulemaking; changes in industry practices absent the rulemaking; and changes in the location and structure of the industry absent the Proposed Rule.

- **Determining the regulated industry response to the Proposed Rule:** The next step in the analysis involves forecasting the behavioral response of the regulated community to the new rule. Specifically, for this analysis, we develop 13 "model mines" of varying size, geographic location, and mining method, and evaluate how the mining industry will adapt to the new requirements under each alternative.

[61] We use the term "stranded coal reserves" to refer to coal that would have been mineable under baseline economic and regulatory conditions, but which is no longer mineable given the requirements imposed by the Proposed Rule.

- **Estimating the total regional and national changes in costs:** The third step is to model, at the regional level, the increase in the cost of coal production resulting from the requirements of the rule and changes in industry behavior. We also estimate costs borne by regulation and enforcement officials (i.e., government) as well as the costs incurred by the regulated community.
- **Estimating welfare losses and economic impacts:** Changes in the cost of producing coal will either result in lower profits to coal producers, and/or higher prices to coal consumers. Higher prices to consumers will result in reduced demand for coal, and will generate changes in economic welfare. Changes in the cost of producing coal in each region may also impact the regional distribution of coal production (i.e., favor some regions and coal production methods over others).
- **Estimating the potential benefits of the regulatory action:** This step involves assessing the benefits of the regulation and quantifying and monetizing those benefits to the greatest extent possible. Benefits are expected to result when changes in industry practices lead to greater environmental or human health protection. Benefits can also result if there is a shift in production to less-environmentally sensitive regions, or to a less environmentally damaging production technique.
- **Assessing distributional impacts:** In addition to estimates in costs and benefits on the net effects of the regulations, stakeholders and decision-makers are interested in the effects of the regulations on specific groups, such as small businesses, specific geographic areas, or governments. As mentioned earlier, analyses of several of these concerns are required by statute and administrative order.
- **Analysis of the alternatives:** OMB directs agencies to consider alternative regulatory schemes, such as different enforcement methods, degrees of stringency, requirements for different sized firms, requirements for different geographic regions, and market-oriented approaches. This section will compare the results for the nine alternatives considered and highlight how their impacts likely differ.

The analysis in the following chapters elaborates on each of these components in detail. This chapter discusses the overall analytical framework. Note that although this analysis attempts to mirror the terms and wording of the Proposed Rule, readers should refer to the regulatory text, rather than the text of this assessment, for a legal description of requirements of the rule.

3.3 DEFINING THE BASELINE FOR ANALYSIS

To understand the incremental changes that occur with the implementation of a new regulation, a baseline – or what the world would look like but-for the new regulation – must first be defined. The Office of Management and Budget's Circular A-4 directs Federal agencies to measure the costs and benefits of a regulatory action against a baseline, which it defines as the "best assessment of the way the world would look absent the proposed action."[62] In other words, the baseline includes the regulatory and economic environment in which the regulated entities would operate *absent the Proposed Rule*. Changes in behaviors required by regulatory requirements that are incremental to that baseline (i.e., occurring over and above existing constraints or conditions) may generate costs that are attributable to the proposed regulation. Since, in the case of coal mining, the baseline regulatory requirements vary regionally, we have developed separate analyses to model the incremental impacts of the Proposed Rule in various coal mining regions, and for various mine types and mine sizes (measured in tons/year).

A number of Federal and State regulations and policies currently provide protection to streams from potential adverse effects of coal mining, including, most importantly, the existing Surface Mining Control and Reclamation Act of 1977 (SMCRA) regulations, the U.S. Environmental Protection Agency (EPA) and U.S. Army Corps of Engineers' (USACE) regulations and policies implementing the Clean Water Act (CWA), State SMCRA regulatory programs, and State and OSMRE policies interpreting and applying Federal and State SMCRA regulatory programs. These regulations and policies already preclude or limit certain mining activities that would otherwise be detrimental to stream quality and flow, and thus provide baseline protections to streams.

SMCRA AND THE STREAM BUFFER ZONE RULES

One of the objectives of SMCRA is to ensure that surface coal mining activities are conducted in an environmentally responsible manner and that the land disturbed by mining is adequately reclaimed. As part of the regulations establishing the initial regulatory program under SMCRA, OSMRE adopted the concept of a 100-foot buffer zone around intermittent and perennial streams. OSMRE permanent program regulations, published on March 13, 1979, included more extensive stream buffer zone (SBZ) rules at 30 CFR §§ 816.57 (for surface mining operations) and 817.57 (for underground mining operations). In 1983, OSMRE revised the stream buffer zone rules to delete the requirement that the original stream channel be restored, replaced the biological community criterion for determining which non-perennial streams must be protected under the rule with a requirement for protection of all intermittent streams, and added a requirement for a finding that the proposed mining activities would not cause or contribute to a violation of applicable state or Federal water quality standards and would not adversely affect the water quality or quantity or other environmental resources of the stream.

Under the regulations implementing SMCRA, surface coal mining and reclamation activities must be conducted in a manner that will "minimize the disturbance of the hydrologic balance within the permit and adjacent areas" and that will "prevent material damage to the hydrologic balance outside the permit area." As part of the SMCRA permitting process, potential changes to the quality and quantity of surface and groundwater are evaluated to ensure that material damage to the hydrologic balance

[62] Office of Management and Budget (OMB). 2003. Circular A-4: Guidance on Development of Regulatory Analysis. Issued September 17, 2003.

outside the permit area will not occur.[63] Other factors considered under SMCRA include: pre- and post-mining land uses, backfilling and grading activities to re-establish approximate original contour, disposal of excess spoil, and the protection or replacement of water supplies.

Historically, OSMRE and the some States interpreted the 1983 SBZ rule to allow the construction of excess spoil fill, refuse piles, and slurry impoundments in intermittent and perennial streams, i.e., the rule was not interpreted in a manner that strictly prohibited all disturbances within the buffer zone. This interpretation resulted in considerable controversy and litigation in Appalachia. Opponents of that interpretation had some success on the merits at the district court level, but the appellate courts reversed these decisions on different grounds, leaving the historical interpretation largely undisturbed.

On December 12, 2008, OSMRE published a revised SBZ rule requiring that operators avoid disturbing perennial and intermittent streams to the extent reasonably possible. That rule, which took effect January 12, 2009, required mine operators to minimize the volume of excess spoil generated by mining operations and design and construct fills to be no larger than needed to accommodate the anticipated volume of excess spoil to be generated. To minimize the size of the excess spoil fills, that rule provided that mining operations must return as much of the overburden as possible to the excavation created by the mine.

The 2008 SBZ rule also provided that, to minimize adverse impacts on fish, wildlife, and related environmental values, the operator must avoid constructing excess spoil fills, refuse piles, or slurry impoundments in perennial and intermittent streams to the extent possible. When avoidance is not possible, that rule required that the operator identify a range of reasonable alternatives for disposal and placement of the excess spoil or coal mine waste, evaluate their environmental impacts, and select the alternative with the least overall adverse impact on fish, wildlife, and related environmental values. The 2008 SBZ rule was only implemented in states with Federal regulatory programs (of which only Tennessee and Washington have active coal mining or reasonably foreseeable coal mining) and on Indian lands.

Soon after the publication of the 2008 SBZ rule, that rule was challenged by several environmental groups. On February 20, 2014, the United States District Court for the District of Columbia vacated the 2008 SBZ rule and reinstated the 1983 SBZ rule.[64] In this RIA, we consider the 1983 SBZ rule to be part of the regulatory baseline for mining activities, and we examine the ongoing policies and practices in individual state SMCRA

[63] Specifically, ssection 507(b)(11) of SMCRA requires that the permit applicant prepare a determination of the probable hydrologic consequences of the proposed operation with respect to the hydrologic regime and the quantity and quality of water in surface and ground water systems. Section 510(b)(3) of SMCRA requires that the regulatory authority use this determination and other available information to prepare an assessment of the probable cumulative impact of all anticipated mining in the area on the hydrologic balance. The SMCRA regulatory authority may not issue a permit unless it first finds that the operation has been designed to prevent material damage to the hydrologic balance outside the permit area. However, the term "material damage to the hydrologic balance" is not defined in either SMCRA or the current regulations.

[64] National Parks Conservation Association v. Jewell, No. 09-115 (D.D.C. Feb. 20, 2014).

programs under the baseline, as described in the next section. The 2008 SBZ Rule is analyzed as Alternative 9.

STATE REGULATIONS AND POLICIES

In areas where coal mining occurs outside of Federal programs, State programs exist that manage coal mining activities and issue SMCRA permits. Some states have developed policies that provide protections that may be more stringent than current SMCRA requirements. In particular, Kentucky and West Virginia have implemented policies that deserve mention. In 2000, the State of West Virginia developed its own policy on approximate original contour (AOC) and Excess Spoil Disposal (known as the AOC+ policy), and Kentucky followed suit in 2009 with its Reclamation Advisory Memorandum (RAM) regarding the "Fill Placement Optimization Process" (known as the RAM 145 policy). These policies were established to facilitate analysis and design of optimized valley fills (i.e., those with the least environmental impacts). While RAM 145 remains a policy, AOC+ has been incorporated into the West Virginia Surface Mining Reclamation Regulations. AOC+ does not directly address stream impacts, but can lessen stream impacts by minimizing the footprints of valley fills. In contrast, RAM 145 evaluates stream length impacted per cubic yard of spoil material, and thus encourages minimization of stream impacts. However, neither AOC+ nor RAM 145 applies to refuse piles or slurry impoundments. In this RIA, we consider these additional state requirements to be part of the regulatory baseline for mining activities within those states.

CLEAN WATER ACT

One of the objectives of the Clean Water Act (CWA) is to "restore and maintain the physical, chemical, and biological integrity of the Nation's waters." To achieve that objective, Section 301 of the CWA prohibits the discharge of pollutants from point sources into waters of the United States unless consistent with the requirements of the Act (33 U.S.C. 1311). Section 402 of the CWA governs the discharge of pollutants other than dredged or fill material (National Pollutant Discharge Elimination System (NPDES) program, 33 U.S.C. 1344), while section 404 governs the discharge of dredged or fill material into waters of the U.S. (33 U.S.C. 1344).

Section 303 Water Quality Standards

Section 303 of the CWA requires states to adopt water quality standards applicable to their intrastate and interstate waters (33 U.S.C. 1313). Water quality standards assist in maintaining the physical, chemical, and biological integrity of a water body by designating uses, setting water quality criteria to protect those uses, and establishing provisions to protect water quality from degradation. Water quality standards established by states[65] are subject to EPA review (40 CFR 131.5; 33 U.S.C. 1313(c)). EPA may object to state-adopted water quality standards and may require changes to the state-adopted water quality standards and, if the state does not respond to EPA's objections, EPA may promulgate Federal standards (33 U.S.C. 1313(c)(3)-(4); 40 CFR 131.5,

[65] EPA may treat an eligible federally recognized Indian tribe in the same manner as a state for implementing and managing certain environmental programs, including under the Clean Water Act.

131.21). Water quality criteria may be expressed numerically and implemented in permits through specific numeric limitations on the concentration of a specific pollutant in the water (e.g., 0.1 milligrams of chromium per liter) or by more general narrative standards applicable to a wide set of pollutants. To assist states in adopting water quality standards that will meet with EPA's approval, Congress authorized EPA to develop and publish recommended criteria for water quality that accurately reflect "the latest scientific knowledge" (33 U.S.C. 1314(a)). Water quality standards are not self-implementing; they are implemented through permits, such as the section 402 permit or the section 404 permit (33 U.S.C. 1311(b)(1)(C); 40 CFR 122.44(d), 230.10(b)).

CWA Section 404

Under section 404 of the CWA, the USACE and the EPA have the authority to regulate discharges of dredged and fill material into waters of the United States. Thus, surface coal mining and reclamation activities involving discharges of dredged or fill material into waters of the United States also require permits issued under section 404 of the Clean Water Act.

The authority for administering the 404 program is shared between USACE and EPA. USACE administers the day-to-day program, including individual and general permit decisions and jurisdictional determinations, develops policy and guidance, and enforces Section 404 provisions. EPA develops and interprets environmental criteria used in evaluating permit applications, identifies activities that are exempt from permitting, reviews/comments on individual permit applications, approves and oversees State and tribal assumption of primacy, enforces Section 404 provisions, and has authority to veto USACE permit decisions.[66]

Under the authority of section 404(b)(1) of the Clean Water Act, EPA and USACE developed Guidelines for the specification of disposal sites for discharges of dredged or fill material into waters of the United States. Those Guidelines, which are codified at 40 CFR Part 230, require the USACE or other permitting authority to evaluate the effects of discharges of dredged or fill material on the physical, chemical, and biological components of the aquatic environment as identified in subparts C through F of 40 CFR Part 230. Those components include substrate; suspended particulates/turbidity; water; current patterns and water circulation; normal water fluctuations; threatened and endangered species; fish, crustaceans, mollusks, and other aquatic organisms in the food web; other wildlife; wetlands; riffle and pool complexes; municipal and private water supplies; recreational and commercial fisheries; water-related recreation; and aesthetics (40 CFR §§ 230.20-230.54).

Paragraph (b) of 40 CFR § 230.10 provides that no discharge of dredged or fill material may be permitted under four specific conditions, which include causing or contributing to violations of any applicable State water quality standard. Paragraph (c) prohibits the discharge of dredged or fill material if the discharge will cause or contribute to significant

[66] U.S. EPA. 2013a. EPA Wetland Regulatory Authority. Accessed 15 May 2013 from: http://water.epa.gov/grants_funding/wetlands/upload/2004_4_30_wetlands_reg_authority_pr.pdf

degradation of the waters of the United States, except as provided under section 404(b)(2) of the Clean Water Act. Paragraph (d) further prohibits the discharge of dredged or fill material into waters of the United States unless appropriate and practicable steps have been taken to minimize potential adverse impacts on the aquatic ecosystem, except as provided under section 404(b)(2) of the Clean Water Act.

EPA exercised its veto authority under section 404(c) of the Clean Water Act in 2009 by retroactively revoking a permit issued by the USACE in 2007 to allow the filling of streams in connection with a large surface coal mining operation in West Virginia. The company challenged the veto and won at the District Court level, but the U.S. Court of Appeals for the District of Columbia Circuit reversed that decision and upheld the veto on April 23, 2013 (*Mingo Logan Coal Company v. U.S. Envtl. Prot. Agency*, Civil Action No. 12-5150; 2013 U.S. App. LEXIS 8121 (D.C. Cir. April 23, 2013)). Mingo Logan appealed to the United States Supreme Court, who declined to hear the case in March, 2014 (714 F. 3d 608). On September 30, 2014, the D.C. District Court ruled in favor of EPA on the issues remanded to it by the D.C. Court of Appeals (D.C. Cir. September 30, 2014).

The USACE may issue "general permits" if the authorized activities would result in no more than minimal individual or cumulative adverse environmental effects (40 CFR § 230.7). These permits expire in five years unless reissued. In particular, Nationwide Permits (NWP) 21 (surface coal mining), NWP 49 (coal remining), and NWP 50 (underground coal mining) were first issued in 1982 to allow coal mining operations to discharge dredged or fill material into waters of the United States. The USACE reissued NWP 21 in 2012 with new limits. Specifically, the revised NWP 21 no longer applied to discharges for the purpose of constructing excess spoil fills; in general, it also no longer applied to any other mining-related activities that would fill more than 1⁄2-acre of waters of the United States or that would result in the loss of greater than 300 linear feet of stream bed (77 FR 10203-10213). As such, surface coal mining operations that result in excess spoil disposal must pursue individual permits if they wish to construct excess spoil fills in waters of the United States or construct other types of fills that exceed the limits in NWP 21.

Section 401 Water Quality Certification

State water quality standards are incorporated into all Federal CWA permits through section 401, which requires each applicant to submit a certification from the affected state that the discharge will be consistent with state water quality requirements (33 U.S.C. 1341(a)(1)). Thus, section 401 provides states with a veto over Federal permits that may allow exceedances of state water quality standards. It also empowers states to impose and enforce water quality standards that are more stringent than those required by Federal law (33 U.S.C 1370).

CWA Section 402

Another objective of the CWA is to "restore and maintain the physical, chemical, and biological integrity of the Nation's waters" by protecting them from pollution. Water pollution can originate from "point source" discharges or "nonpoint source" discharges.

Point source pollution includes "pollutant load discharges at a specific location from pipes, outfalls, and conveyance channels from either municipal wastewater treatment plants or industrial waste treatment facilities." This type of pollution is regulated through the EPA's NPDES program under section 402 of the Clean Water Act, which governs discharges of pollutants other than dredged or fill material into waters of the U.S..

All point source discharges from coal mining operations, such as sedimentation ponds or treatment pond outfalls, are subject to NPDES permitting requirements and require a permit. NPDES permits help to implement the goals of the CWA by defining discharge limits, sampling, and monitoring requirements for pollutants that can degrade U.S. water resources. NPDES permits typically contain numerical limits called effluent limitations that restrict the amounts of specified pollutants that may be discharged. NPDES permits must contain technology-based effluent limits and any more stringent water quality-based effluent limits necessary to meet applicable state water quality standards (33 U.S.C. 1311(b)(1)(A) and (C), 33 U.S.C. 1342(a); 40 CFR 122.44(a)(1) and (d)(1)). Water quality-based effluent limitations are required for all pollutants that the permitting authority determines "are or may be discharged at a level [that] will cause, have the reasonable potential to cause, or contribute an excursion above any [applicable] water quality standard, including State narrative criteria for water quality" (40 CFR 122.44(d)(1)(i)). Section 402 permits are issued by EPA unless the state has an approved program whereby the state issues the permits, subject to EPA oversight (33 U.S.C. 1342(b)(e); 551 U.S. 644, 650-651 (2007)).

Enhanced Coordination Procedures and EPA Guidance on Appalachian Coal Mining

From 2005 to 2009, CWA Section 404 permits were the subject of litigation in West Virginia.[67] In 2009, a Memorandum of Understanding (MOU) was signed by the Department of the Interior, the USACE, and the EPA, in order to "significantly reduce the harmful environmental consequences of Appalachian surface coal mining operations, while ensuring that future mining remains consistent with federal law."[68] The MOU called for coordinated environmental reviews of pending permit applications under the CWA and SMCRA.[69]

To efficiently process a backlog of pending Section 404 permits, EPA and the USACE issued Enhanced Coordination Procedures (ECP) on June 11, 2009. The list of permits to which ECP was applied initially included 108 permits in the Appalachian region, but was limited to 79 permits in September 2009.[70] However, on October 6, 2011, the United States District Court for the District of Columbia ruled that, with the adoption of the ECP, EPA exceeded its statutory authority afforded by the CWA. The court also ruled that the

[67] Office of the Inspector General. 2011. Congressionally Requested information on the status and length of review for Appalachian surface mining permit applications. Report number 12-P-0083, November 21, 2011.

[68] U.S. Department of the Army, U.S. Department of the Interior, and U.S. Environmental Protection Agency. 2009. Implementing the Interagency action plan on Appalachian Surface Coal Mining. Memorandum of Understanding.

[69] Ibid.

[70] Office of the Inspector General. 2011. Congressionally Requested information on the status and length of review for Appalachian surface mining permit applications. Report number 12-P-0083, November 21, 2011.

ECP are legislative rules not exempt from the Administrative Procedure Act's notice and comment rulemaking requirements. The court ordered the ECP be set aside as an unlawful agency action.[71] On July 11, 2014, the U.S. Court of Appeals for the D.C. Circuit overturned the lower court's decision.[72] As such, ECP is considered part of the regulatory baseline for this rule.

EPA also developed guidance for review of applications for permits for Appalachian surface coal mining operations under the CWA (EPA Permitting Guidance), which was finalized on July 21, 2011.[73] This guidance was intended to clarify EPA's roles and expectations in permitting surface coal mining operations under section 402 and 404 of the CWA, and to "assure more consistent, effective, and timely review of Appalachian surface coal mining operations with respect to provisions of the CWA, the National Environmental Policy Act, and Environmental Justice Executive Order, as implemented by USEPA and USACE." This guidance included protective actions that went beyond the 2008 SBZ rule with regard to excess spoil placed in streams (i.e., these requirements imposed further requirements on mine design). The U.S. District Court for the District of Columbia set aside the EPA Permitting Guidance in July 2012.[74] However, in its July 31, 2014 decision related to the ECP, the U.S. Court of Appeals for the D.C. Circuit also held that the EPA Permitting Guidance was not "a final agency action subject to pre-enforcement review."[75] Because this appellate decision relied on the fact that the EPA Permitting Guidance did not "impose any obligations or prohibitions on regulated entities [and] State permitting authorities 'are free to ignore it[,]'"[76] the RIA does not consider the EPA Permitting Guidance as part of the regulatory baseline for this rule.

FEDERAL ACTIONS RELATED TO COAL COMBUSTION

Future coal demand in the U.S. will depend not only on changes in the size and composition of the U.S. economy over time, but also the suite of environmental regulations developed by EPA and other agencies to limit the adverse environmental and human health impacts of coal combustion. These regulations address a variety of environmental impacts, including particulate and ozone pollution, human exposure to toxic air pollutants (e.g., lead and mercury), contamination of groundwater and surface water, and climate change.

[71] Nat'l Mining Ass'n v. Jackson, 816 F. Supp. 2d 37 (D.D.C. 2011); Office of the Inspector General. 2011. Congressionally Requested information on the status and length of review for Appalachian surface mining permit applications. Report number 12-P-0083, November 21, 2011.

[72] Nat'l Mining Ass'n v. McCarthy, 758 F.3d 243 (D.C. Cir. 2014).

[73] Stoner, N. and Giles, C. 2011. Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the Environmental Justice Executive Order. U.S. EPA.

[74] Nat'l Mining Ass'n v. Jackson, 880 F. Supp. 2d 119 (D.D.C. July 31, 2012).

[75] Nat'l Mining Ass'n v. McCarthy, 758 F.3d at 253.

[76] Id. at 252.

EPA and other agencies have finalized and implemented several rulemakings that seek to reduce impacts from coal-fired electricity generating units (EGUs) in the U.S. The following regulations are part of the regulatory baseline:

- ***Mercury and Air Toxics Standards (MATS)***: EPA issued the final MATS rule in December 2011. The rule replaced the Clean Air Mercury Rule, which was vacated by the D.C. Circuit Court in 2008. In 2013, the EPA updated emissions limits for new power plants. On April 15, 2014, after the consideration of public comments and state petitions, the U.S. Court of Appeals for the D.C. Circuit upheld MATS.[77] Between April 2015 and April 2015, EPA proposed several updated and technical corrections to the rule, as well an interim final rule on reporting requirements. Compliance generally requires the addition of scrubbers or dry sorbent injection to meet chlorine requirements, activated carbon injection or a scrubber/selective catalytic reduction combination to meet mercury requirements, and fabric filters or electrostatic precipitator (ESP) upgrades to meet particulate requirements. According to EPA, existing sources will generally have up to four years to comply.[78]

- ***Clean Air Interstate Rule (CAIR):*** EPA issued CAIR on March 10, 2005. This rule established a cap and trade system between 27 eastern U.S. states to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x) by 70 percent. States must achieve required emissions reductions either through this cap and trade system or by individually determined reduction measures. As decisions regarding the Cross-state Air Pollution Rule (see below) are made, CAIR remains in effect.[79]

- ***Cooling Water Intake Structures Rule***: EPA developed regulations under Section 316(b) of the Clean Water Act to limit injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants. A final rule for existing electric generating plants and factories was issued in May 2014. EPA estimates that this rule applies to 544 power plants and requires them to comply with new regulations on the design and operation of water intake structures in order to minimize environmental degradation. EPA's RIA for the Proposed Rule presented the expected change in aggregate electricity generation, but did not include an estimate specific to coal-based generation.[80]

- ***Coal Combustion Residuals Rule***: EPA recently developed regulations governing the management of coal combustion residuals, which were previously considered exempt wastes under the Resource Conservation and Recovery Act (RCRA). On December 19, 2014, the EPA Administrator signed a Final Rule to regulate the management of coal combustion residuals as a solid waste under

[77] White Stallion Energy Ctr., LLC v. EPA, 748 F.3d 1222 (D.C. Cir. 2014)

[78] U.S. EPA. 2012a. Mercury and Air Toxics Standards (MATS): Basic Information. Accessed from: http://www.epa.gov/airquality/powerplanttoxics/basic.html

[79] U.S. EPA. 2012b. Clean Air Interstate Rule (CAIR). Accessed June 2014 from: http://www.epa.gov/cair/index.html

[80] U.S. EPA. 2014a. Cooling Water Intakes. Accessed June 2014 from: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/

Subtitle D of RCRA. The RIA did not examine the electricity generation impacts of the rule.

Regulators are engaged in several additional rulemakings that seek to reduce impacts from coal-fired EGUs. To the extent that these rules cause power producers to substitute natural gas and other alternatives for coal, they could reduce the power sector's demand for coal. These rules and their current status (as of summer 2014) are as follows:

- ***Cross-state Air Pollution Rule (CSAPR), or "The Transport Rule":*** EPA finalized CSAPR on July 6, 2011 as a replacement for CAIR. The D.C. Circuit Court stayed the rule in December 2011[81] and vacated it in August 2012, leaving CAIR in place.[82] In April 2014, the Supreme Court reversed the D.C. Circuit opinion and upheld CSAPR.83 In June 2014 EPA filed a motion to lift the stay of the rule and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. Accordingly, CSAPR Phase 1 implementation is now scheduled for 2015, with Phase 2 beginning in 2017. When in place, the rule would require power plants in 28 states to reduce emissions that contribute to ambient ozone and/or fine particle pollution. The final rule RIA estimates that CSAPR will reduce coal-fired electricity generation by 1.9 percent.[84]
- ***Greenhouse Gas New Source Performance Standards (NSPS) for Electric Utility Generating Units (EGUs):*** EPA proposed an NSPS for greenhouse gases in new coal-fired power plant in September 2013. The proposal establishes emission rates for CO_2 per megawatt-hour. Compliance would likely require some form of carbon capture and sequestration (CCS). The RIA showed no impact on new coal plant construction during the evaluation period because it is likely that new coal plants will already meet these standards, regardless of the proposal.[85] Publication of the final rule is expected in January 2015.
- ***Clean Power Plan (Proposed Rule):*** In June 2013, President Obama directed EPA to use its authority under Section 111(d) of the Clean Air Act to issue standards, regulations, or guidelines that address carbon emissions from modified, reconstructed, and existing power plants. On June 2, 2014, EPA proposed a plan to cut carbon emissions from existing power plants. This rule sets state-specific rate-based goals for CO_2 emissions. The final rule RIA

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[81] EME Homer City Generation, L.P. v. EPA, 696 F.3d 7, 19 (D.C. Cir. 2012).

[82] Id. at 37-38.

[83] EPA v. EME Homer City Generation, L.P., 134 S. Ct. 1584 (2014).

[84] U.S. EPA. 2014b. Cross-State Air Pollution Rule (CSAPR). Accessed June 2014 from: http://www.epa.gov/airtransport/CSAPR/

[85] U.S. EPA. 2013b. Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units. Accessed June 2014 from: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf

estimates that coal production for the power sector will decrease by 25 to 27 percent in 2020 and 30 to 32 percent in 2030, from base case levels.[86,87]

- ***Coal Combustion Residue Placement at Coal Mines Rule***: OSMRE is currently developing specific regulations and preparing an Environmental Assessment under NEPA for protection of the environment when operators or owners place coal combustion residues (CCRs) at active and abandoned coal mines regulated under the SMCRA. The National Academy of Science published a report in 2006 on managing CCRs in mines that recommended the establishment of enforceable Federal standards that provide explicit authority and minimum safeguards for the placement of CCRs in mines.[88]

ECONOMIC BASELINE

In addition to existing regulatory requirements, the demand for coal and the price at which coal is provided to the market under baseline conditions in the future will affect the magnitude of costs and benefits of implementing SPR compliance actions. The baseline demand for coal from a given region will be influenced by numerous exogenous factors (i.e., factors unrelated to this rulemaking), including: reserve depletion; changes in relative production costs; changes or limitations in transportation capability and cost; growing demands for low-sulfur coal; the abundance of, and relative cost of, alternatives to coal for electricity production (especially natural gas); changes in demand for steam coal resulting from the adoption of renewable portfolio standards for utilities; changes in demand for metallurgical coal (driven by domestic levels of iron and steel production, as well as demand from overseas); and changes in demand in the U.S. export market. Our model assumptions about future coal demand and supply are discussed in Chapter 5 of this RIA and Appendix F.

Several factors affecting the demand for coal warrant closer consideration. Key aspects of economic growth and energy markets that affect the future demand for coal independent of the Proposed Rule include the following:

- ***Electricity demand growth***: Because power plants account for approximately 93 percent of the coal consumed in the U.S.[89], the trajectory of electricity demand growth will significantly affect the size of the domestic coal market.
- ***Demand for U.S. coal exports****:* Our assumptions regarding baseline coal production in the U.S. depend, in part, on growth in demand for U.S. coal exports. Export demand reflects a number of factors including exchange rates, economic activity in export markets, and the price of coal in export markets

[86] U.S. EPA. 2014c. Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Exiting Power Plants and Emission Standards for Modified and Reconstructed Power Plants. Accessed June 2014 from: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf

[87] The Clean Power Plan is part of the low coal demand scenario.

[88] National Research Council of the National Academies. 2006. Managing Coal Combustion Residues in Mines. The National Academies Press, Washington D.C. Accessed June 2014 from: http://www.nap.edu/openbook.php?record_id=11592

[89] U.S. EIA. 2013c. Annual Coal Distribution Report 2012. U.S. Department of Energy.

relative to alternative sources of energy (e.g., oil and natural gas). In addition, the ability of domestic coal producers to meet this demand depends on the capacity of rail networks to transport coal to ports, and the capability of those ports to move this coal.

- ***Natural gas supply:*** Long-term trends in coal markets will also depend on developments in natural gas markets. EIA's estimate of viable domestic (wet) natural gas reserves increased from 284 trillion cubic feet (tcf) in 2009 to 349 tcf in 2011. However, these reserves decreased by 7.5 percent in 2012 (to 323 tcf), largely because of low natural gas prices.[90] In addition, the average wellhead price of gas declined by 3.24 percent from 2011 to 2012. EIA projects modest growth in prices from 2012 through 2040 (1.3 percent per year).[91] To the extent that EIA over- or under-estimates reserves, natural gas prices may deviate from this projected path. Given that coal and natural gas are substitutes in the production of electricity (and in industrial boilers), changes in natural gas markets could spill over to coal markets.

We note that developments in natural gas markets are not independent of potential EPA regulatory changes outlined above. Because the combustion of natural gas yields decreases emissions of criteria pollutants and CO_2 per BTU consumed, the EPA rules may further affect natural gas supply, demand, and pricing.

3.4 GEOGRAPHIC STUDY AREA FOR ANALYSIS

As described in Chapter 2, coal resources are widely distributed across the U.S. However, not all coal resources are accessible with current technologies. Further, some potentially mineable coal resources are unlikely to be mined in the near-term due to economic conditions. To establish a reasonable boundary for the likely geographic areas to be affected by the Proposed Rule in the timeframe for this analysis (2020 to 2040), the geographic scope for this analysis was defined as follows:

- Spatial data compiled by the U.S. Geological Survey Eastern Energy Resources Center on potentially minable coal fields defined the initial extent of the study area. Coal fields were identified as potentially minable if they contained coal of sufficient quality and energy content to justify extraction, based on existing data.[92]
- From the practicably minable coal fields data, areas considered likely to produce coal within the timeframe for this analysis include areas within counties that:

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[90] U.S. EIA. 2013d. U.S. Crude Oil, and Natural Gas Liquids Proved Reserves, 2012. U.S. Department of Energy.

[91] U.S. EIA. 2014c. Annual Energy Outlook 2014: With projections to 2040. U.S. Department of Energy, Office of Integrated and International Energy Analysis.

[92] United States Geologic Survey (USGS). 2001. National Atlas of the United States: Coal Fields of the United States. Eastern Energy Team; John Tully (comp.), Reston, VA. http://nationalatlas.gov/mld/coalfdp.html.

- Reported coal production between 2007 and 2012 in EIA Annual Coal Reports;[93]
- Contain pending but administratively complete SMCRA permits in the OSMRE Applicant/Violator System (AVS) as of September 2011;
- The Mine Safety and Health Administration reports as containing active coal mines as of April 2013;[94]
- State-level mining assessments, geographic data, or tabular data report as containing active coal mining activity as of August 2012. State-level information contributed additional counties in Colorado, Illinois, Kentucky, Ohio, West Virginia, Texas, and Alaska.[95]
- Urban areas, lakes, and ponds were removed from the study area, as mining is not expected to take place in these areas. However, some mining may take place under or adjacent to lakes and ponds, so the study area may slightly under-represent the areal extent of mining.[96]

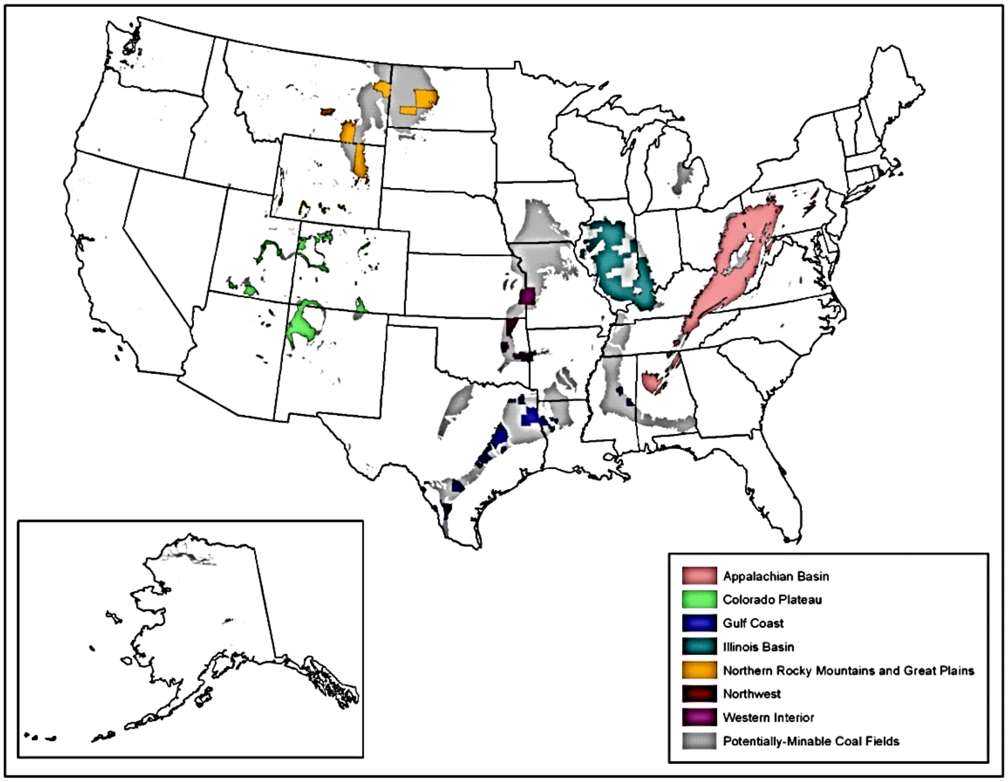
[93] U.S. EIA. 2008-2013. Annual Coal Reports 2007 through 2012. U.S. Department of Energy.

[94] MSHA. 2013a. Mines Data Set. U.S. Department of Labor. http://www.msha.gov/opengovernmentdata/ogimsha.asp.

[95] Colorado Division of Reclamation Mining and Safety. 2010. GIS Data. Department of Natural Resources. http://mining.state.co.us/Reports/Pages/GISData.aspx; Illinois State Geological Survey. 2011. Coal Maps and Data. https://www.isgs.illinois.edu/research/coal/maps; Kentucky Department of Natural Resources, Division of Mine Permits. 2011. Permit Locations. http://minepermits.ky.gov/Pages/SpatialData.aspx; Ohio Department of Natural Resources, Division of Mineral Resources Management. 2011. Issued Coal Permits; West Virginia Department of Environmental Protection, Division of Mining and Reclamation. 2011. Mining Permit Boundaries. http://gis.dep.wv.gov/data/omr.html; Railroad Commission of Texas, Surface Mining and Reclamation Division. 2011. Active Coal Mines. http://www.rrc.state.tx.us/about-us/organization-activities/divisions-of-the-rrc/surface-mining-reclamation-division/; Alaska Department of Natural Resources, 2011. Division of Mining, Land, and Water. http://dnr.alaska.gov/mlw/mining/coal/index.htm. The program description for the Alaska Coal Regulatory Program states that active mining currently only occurs near Healy, AK, in the Denali Borough. State-specific data for other states were examined where available, but contributed no additional counties beyond those listed by EIA.

[96] U.S. Census Bureau. 2000. Census 2000: Urbanized Areas; USGS. National Hydrography Dataset. http://nhd.usgs.gov/

EXHIBIT 3-1. STUDY AREA FOR ANALYSIS



Sources: USGS. 2001. National Atlas of the United States: Coal Fields of the United States. U.S. Department of the Interior; National and state-specific spatial data (see footnotes above).

3.5 DETERMINING EXPECTED CHANGES IN INDUSTRY PRACTICE DUE TO THE PROPOSED RULE: USE OF A MODEL MINES ANALYSIS

Coal mining operations vary from region to region, within a region, and within a mining type in a given region. In addition, the population of active mines is expected to change over time; as such, the precise location of the population of future mines cannot be forecast based on publicly available data. Given a lack of a mine-specific forecast of future operations, it is not possible to forecast for each specific mine how operations will change in the future under the Proposed Rule. Instead, this analysis relies on a "model mine" analysis. These model mines are hypothetical mines that are intended to be representative of the locations where coal mining occurs, the types of mining operations expected to be seen under baseline conditions, and the production volumes at various mines throughout the coal producing regions of the United States.

Because it is impossible to capture the unique topography, geology, previous mining activities, land ownership characteristics, and other characteristics associated with each individual mine, the analysis is intended to provide a measure of the scope and scale of potential changes under each alternative. That is, the analysis is designed to be representative, on average, of the expected impacts of the Proposed Rule across regions and the coal mining industry.

The purpose of the model mine analysis is to approximate how mining operations in each region might change operations or be designed in response to different requirements and elements of each alternative, and to develop metrics that can be used to further calculate the benefits and impacts of the alternatives. This analysis designed and analyzed thirteen "representative" model mining operations, which are categorized by region and size (tons of coal produced annually), as detailed in Exhibit 3-2.

EXHIBIT 3-2. MODEL MINE DEFINITIONS

REGION	SURFACE OR UNDERGROUND	ANNUAL PRODCUTION (MILLION TONS)
Central Appalachia	Surface - Area	2.3
	Surface - Contour	0.5
	Underground (Room and Pillar)[2]	0.3
Northern Appalachia	Surface – Contour	0.2
	Underground (Longwall)[2]	4.6
Colorado Plateau	Surface – Area	3.3
	Underground (Longwall)[2]	3.0
Gulf Coast	Surface – Area	3.3
Illinois Basin[2]	Surface – Area	1.0
	Underground (Room and Pillar)[2]	2.1
	Underground (Longwall)[2]	6.0
Northern Rocky Mountain and Great Plains	Surface – Area	2.0
Northwest	Surface – Area	2.0
Western Interior[2]	Surface – Area	1.0
	Underground (Room and Pillar)	2.1

[1] The analysis also designed coal refuse facilities associated with these underground mining operations.

[2] The model developed for Illinois Basin surface and room and pillar underground mines were also used to evaluate impacts to the Western Interior mining activities.

The detailed process of developing the model mines analysis is described in Appendix B. A summary of the procedure is as follows:

- Identify the predominant types of coal mining activity in each region by mining method and size, based on typical production levels. Thirteen mine "types" are identified in this process.

- Configure model mines. This process involves reviewing actual mine permit data for each mine type. Engineers then select appropriate topography, geology, and stream locations for each mine type, using a combination of actual permit data from mines in the relevant regions and topographic data from USGS. Mine locations are designed so that any permit data that is used could not be linked to an actual mining operation.
- Review the Proposed Rule Alternatives and assess the impacts of each rule element on current mine operations at each of the 13 model mine locations.
- Develop and calculate metrics to assess costs, impacts, and benefits of each alternative on each model mining operation. Also assess potential impacts of each alternative on coal refuse impoundments in applicable regions. Key metrics include:
    - Stream miles directly impacted by mining operations;
    - Stream miles restored and enhanced;
    - Change in topography, in terms of post-mining slope (percent change);
    - Acres of land disturbed;
    - Acres of land reforested; and
    - Acres of riparian zone restored.
- The outcome of the model mines analysis includes, for each model mine, increased operational costs per tons of coal produced.

3.6 ESTIMATING TOTAL COMPLIANCE COSTS

Compliance costs are comprised of administrative costs borne by private entities, costs associated with changes to operations and/or additional capital costs required to comply with the Proposed Rule (as borne by mine owners and operators), and costs to State and Federal governments associated with implementing the rule. Chapter 4 describes the compliance cost estimation method in detail. As detailed in Chapter 4.2, first calculated for each model mine, these costs are then translated to costs per ton of coal produced using recent coal production data for active mines. These costs are then applied to forecast regional coal production forecasts to arrive at estimates to total compliance costs by region. These regional compliance costs can then be summed to arrive at total compliance cost estimates.

- **Administrative and Governmental Compliance Costs**: These costs were calculated based on an assessment by OSMRE of the paperwork requirements of the rule. Detailed assumptions are described in Chapter 4 of this analysis.
- **Operational Costs**: As part of the model mines analysis, additional costs to private entities are estimated. Detailed assumptions about development of these costs are provided in Appendix B.

3.7 ESTIMATING WELFARE LOSSES AND ECONOMIC IMPACTS

CHANGES IN NET MARKET WELFARE

Under some of the alternatives in some regions, there may be a change in the price and overall quantity of coal produced.[97] To address this outcome, we evaluate market welfare losses, in the form of consumer and producer surplus changes. Changes in consumer and producer surplus are measured assuming linear supply and demand functions.

Understanding the economic welfare effects of the Proposed Rule involves understanding the U.S. energy market more broadly, as discussed in the next section.

ASSESSMENT OF ENERGY MARKET EFFECTS

As noted above, the Proposed Rule may affect the regional distribution of domestic coal production. It may also impact U.S. energy markets more broadly. That is, any appreciable increase in the market price of coal may cascade to other U.S. energy markets, as energy consumers switch to other fuels such as natural gas, causing an increase in the price of these substitutes. In the context of the Proposed Rule, the potential for substitution effects is most significant in the electricity sector, given that power plants use approximately 90 percent of the coal consumed in the U.S. on an annual basis. If the cost of producing electricity increases, due to either higher coal prices or the costs of switching to alternatives, electricity prices may also increase.

To assess the coal market impacts of the rule, we use the coal market model developed and maintained by Energy Ventures Analysis (EVA). Originally designed to generate detailed forecasts of coal supply, demand, and pricing, the EVA model accounts for the various regulatory and operational constraints that may affect the coal market. For the analysis of the Proposed Rule, we adapt the model to develop separate forecasts for the regulatory baseline(s)[98] and the policy scenarios under consideration. To model each policy scenario, the increase in coal production costs, expressed on a per-ton basis for individual regions and coal types, is incorporated into the EVA model as upward shifts in the appropriate coal supply curves. The difference between the resulting baseline and policy forecasts would represent the coal market impacts of the Proposed Rule.

We use the EVA model for this analysis because of its detailed treatment of both coal supply and demand. To estimate supply, the model considers a wide range of issues related to coal production, including reserve depletion, coal mining technology, permit restrictions (e.g., the impact of valley fill permit limits on Appalachian surface mining), mine safety regulations, labor availability and costs, and the availability and cost of Federal coal leases. In addition, the coal supply database that underlies the EVA model expands upon the Energy Information Administration (EIA) data used in many other models. Supplementing the EIA data, the model's database includes information from

[97] In some cases we would expect to see a shift in the region in which coal is produced, as relative production costs change. This may lead to a smaller overall change in production, and thus overall smaller consumer surplus effects, than we would expect to see if there was only one supply region.

[98] To assess the impacts of the Proposed Rule relative to multiple baselines, given the current regulatory and market uncertainty (e.g., Clean Power Plan proposed by EPA is part of the low coal scenario).

state public utility commission reports, barge shipment data from the U.S. Army Corps of Engineers, Commerce Department data on coal exports and imports, and Mine Safety and Health Administration data on coal production by mine.

With respect to demand, the EVA coal market model generates long-term forecasts by sector (e.g., power plants, industrial boilers, etc.) using a bottom-up, plant-by-plant approach for most sectors. The coal demand sectors in the model include:

- Electric power;
- Domestic metallurgical coal consumers (coke ovens and pulverized coal injection);
- Industrial consumers (industrial boilers, cement kilns, etc.);
- Commercial consumers (universities, public buildings, etc.);
- Export metallurgical consumers; and
- Export steam.

Using the detailed production cost and demand information outlined above, the EVA model forecasts coal prices by region and coal quality.

Where the results of the EVA coal modeling analysis suggest that the Proposed Rule will materially affect coal prices, we use EVA's Integrated Fuel and Electricity Model to assess the broader energy market impacts of the Proposed Rule. Designed specifically to assess the impacts of regulation and changes in industry practices, the model projects changes in fossil fuel demand, domestic production, and prices. To estimate demand for each segment of the energy market, the model applies own-price and cross-price elasticities to projected changes in price, enabling it to capture iterative feedback effects within energy markets. With respect to fuel supply, the model draws from EVA's detailed models of coal, natural gas, and oil production. In addition, as illustrated in Exhibit 3-3, the model calculates the least-cost mix of electricity generation to meet demand under various regulatory constraints. Unlike other models that use fuel prices as an input, the EVA model estimates energy prices endogenously based on production costs and demand. The model also applies unit-specific abatement cost curves to identify the least-cost strategy for complying with emissions standards. Because these costs vary by fuel type, this is an important feature of the model in the context of the Proposed Rule, given that coal is a relatively NO_x and SO_x-intensive fuel. As noted above, EVA designed the model as an iterative system to capture feedback effects within energy markets. Thus, the model continues to iterate until it converges on an equilibrium solution.

ALTERNATIVE BASELINE SCENARIOS

Focusing on economic factors affecting the demand for U.S. coal, two alternative baselines are analyzed, reflecting "high coal demand" and "low coal demand" scenarios. These scenarios deviate from the primary baseline based on assumptions regarding natural gas prices, U.S. coal exports, and U.S. regulatory actions, primarily the Clean Power Plan proposed by EPA. The assumptions of the two scenarios are outlined in Exhibit 3-3.

EXHIBIT 3-3. ALTERNATIVE COAL DEMAND SCENARIOS

	LOW COAL DEMAND	HIGH COAL DEMAND
Description of Scenario	Clean Power Plan proposed by EPA in June 2014 assuming individual state compliance using mass-based limits.	High natural gas prices combined with higher coal exports
Explanation	The Clean Power Plan results in a significant reduction in utility demand by 2020 according to both EPA and EVA analyses.	Utility coal demand is capped by installed coal capacity. With a significant amount of coal capacity being retired and no new coal capacity forecast, the upside potential demand is limited. With higher gas prices, highest coal demand was realized.

VALUATION OF STRANDED RESERVES

One potential measure of the Proposed Rule's costs under some regulatory alternatives is the reduction in coal reserve values associated with the rule. We examine whether coal reserves may be "stranded" – i.e., effectively unavailable for production given the new requirements of the Proposed Rule. From a welfare economics perspective, this would represent a market welfare cost associated with the Proposed Rule.

If there are reserves that mines would be unable to extract from the ground due to the Proposed Rule, the loss in reserve value would be the baseline value of these reserves, as represented by the present value of the *economic* profits that mines (or the land owner) would earn on these reserves over time, where economic profit is specified as the value of the coal, as extracted, minus the cost of extraction, including normal profits (i.e., opportunity costs of capital).[99] This value may be derived from recent transaction prices for the sale of coal reserves.

3.8 ESTIMATING BENEFITS OF THE RULE

The specific methods and data relevant to the benefits analyses vary significantly by resource. A detailed description of the methods applied in each impact analysis is provided for the relevant resource categories in Chapter 7. However, analytic uncertainty and data limitations preclude reliable monetization of these quantified benefits.

For some resource categories, the analysis describes impacts in quantitative terms (e.g., stream miles impacted, acres affected). Where data limitations prevent reliable quantification of impacts to a given resource, we discuss potential impacts qualitatively. With respect to the quantified impacts, this analysis estimates the benefits of changes in mine management methods due to the regulatory alternatives as follows:

[99] Normal profit represents the return necessary to keep capital deployed in its current use in the long run.

Step 1. Estimate the change in affected natural resource parameters across Alternatives at each model mine. Similar to the compliance cost analysis, this step involves estimating the changes in impacts to natural resources for each model mine across each alternative.

Step 2. Express the change in the affected natural resource parameters as a ratio to the volume of coal produced at each model mine. Use model mine analysis results to estimate the expected changes in natural resource services per ton of coal produced.

Step 3. Estimate total regional impacts. Multiply total expected coal production (or changes in production) by the ratios developed in Step 2 to estimate total impacts of the alternatives by region.

Generally, environmental benefits of the rule may be generated via two pathways. First, mine sites may continue to extract coal but operational changes reduce the impact on environmental resources. Second, to the extent that coal production declines, the reduction in production may yield environmental benefits.

3.9 DISTRIBUTIONAL EFFECTS

Measurements of changes in economic efficiency (i.e., consumer and producer surplus) focus on the net impact of proposed regulatory actions, without consideration of how certain economic sectors or groups of people are affected. Thus, a discussion of efficiency effects alone may miss important distributional considerations. As discussed above, several statutes, such as RFA/SBREFA and UMRA, require agencies to consider the distributional impacts of their regulations. Furthermore, Executive Order 12898 directs agencies to consider specifically human health and environmental impacts on low-income and minority populations.

REGIONAL ECONOMIC EFFECTS

For regulations that may impose a burden on specific geographic areas within the U.S., regional economic impact analysis can provide an assessment of the potential localized effects. In general, “regional economic impacts” describe changes in the flow of money throughout the economy due to a new project or policy. These changes can be measured as total dollars, as specific types of spending (e.g., on wages for employees), as employment demand, and as tax effects. Forecast shifts in the geographic distribution of coal production, the manner in which coal is produced (e.g., surface versus underground), and the total quantity of coal produced, are expected to lead to changes in regional coal industry employment, even absent the Proposed Rule. Chapter 6 discusses this analysis in detail.

Predicting and tracking specific employment effects of this Proposed Rule is difficult to disentangle from other ongoing economic and technological trends. The reaction of labor market to increased regulation is complex. As such, anticipating the future response of the coal industry to the Proposed Rule is challenging. Compliance costs of the Proposed Rule are anticipated to result in changes to regional coal industry employment that will be added to and combined with ongoing trends. We estimate the direct employment demand changes attributable to the Proposed Rule due to anticipated changes in future coal production relative to the baseline forecast (production-related effects). This effect is measured in full time equivalents (FTEs i.e., one full time worker employed for one year). Since the Proposed Rule is expected to reduce the volume of coal produced, we forecast a reduction in employment demand due to this factor.

We also estimate some change in economic activity attributable to the cost of industry compliance with the rule. These direct industry compliance costs are detailed in Chapter 4 of this analysis. These activities are expected to increase demand for labor as a result of the rule (compliance-related effects). Specifically, some increases in employment demand due to work requirements imposed on mining operations by the Proposed Rule could occur. These additional work requirements include performing inspections, conducting biological assessments, and other tasks that require employment of highly trained professionals (e.g., engineers and biologists) as part of compliance with some elements of the Proposed Rule. Other increased work requirements associated with elements contained in the Proposed Rule are expected to require similar skills as currently utilized by the industry (e.g., bulldozer operations). In general, while some of the increased employment demand may utilize existing mining labor skills (e.g., requirements that require additional earth moving), other employment demand from the Proposed Rule may require other types of labor (e.g., biological monitoring, lab testing, paperwork). That is, some additional jobs created by the Proposed Rule may differ in skill requirements from the production-oriented jobs that would be reduced due to decreased coal production.

We estimate the direct effects of compliance requirements and changes in coal production on employment demand and labor income in this analysis. In addition to these direct effects, "ripple" impacts are also likely to occur associated with 1) changes in spending by local industries buying goods and services from other local industries (sometimes called indirect effects), as well as 2) changes in household consumption arising from changes in employment and associated income. We recognize the existence of these effects but do not quantify these in this analysis due to the high level of uncertainty associated with quantifying the scale of these effects.

Note that, while we consider expected shifts in employment within the coal mining sector from one region to another, we do not consider the employment gains and losses that might be associated with changes in demand for other fuels (e.g., natural gas) or changes in employment associated with changes in electricity prices, etc.

SMALL BUSINESS EFFECTS

This analysis looks specifically at the distributional consequences of the Proposed Rule on small businesses. First enacted in 1980, the Regulatory Flexibility Analysis (RFA) was designed to ensure that the government considers the potential for its regulations to unduly inhibit the ability of small entities to compete. The goals of the RFA include increasing the government's awareness of the impact of regulations on small entities and to encourage agencies to exercise flexibility to provide regulatory relief to small entities.

When a Federal agency proposes regulations, the RFA requires the agency to prepare and make available for public comment an analysis that describes the effect of the rule on small entities (i.e., small businesses, small organizations, and small government jurisdictions).[100] For the Proposed Rule, this analysis takes the form of an initial regulatory flexibility analysis (IRFA). Under 5 U.S.C. § 603(b), an IRFA is required to contain:

- A description of the reasons why action by the agency is being considered;
- A succinct statement of the objectives of, and legal basis for, the Proposed Rule;
- A description of and, where feasible, an estimate of the number of small entities to which the Proposed Rule will apply;
- A description of the projected reporting, recordkeeping and other compliance requirements of the Proposed Rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;
- An identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap, or conflict with the Proposed Rule; and
- Each initial regulatory flexibility analysis shall also contain a description of any significant alternatives to the Proposed Rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the Proposed Rule on small entities.

This analysis and these requirements are described in Appendix A.

3.10 DATA SOURCES

The following is a list of the sources for the primary data sources used in this report:

- Mine Safety and Health Administration (MSHA);
- United States Census Bureau;
- Bureau of Labor Statistics (BLS);
- EVA coal models;
- Morgan Worldwide model mine analysis;
- U.S. Energy Information Administration (EIA);
- U.S. Environmental Protection Agency (EPA);
- IMPLAN; and
- OSMRE.

[100] 5 U.S.C. § 601 et seq.

3.11 KEY UNCERTAINTIES AND LIMITATIONS TO THE ANALYSIS

The forecasts of coal demand, production, and industry response to the implementation of the final regulation are subject to uncertainty. The key uncertainties and how they are addressed in this analysis are presented in Exhibit 3-4.

EXHIBIT 3-4. TREATMENT OF KEY UNCERTAINTIES IN THE REGULATORY IMPACT ANALYSIS

UNCERTAINTY	TREATMENT OF UNCERTAINTY
Compliance costs and changes in industry behavior that will be associated with this rulemaking are not known with certainty.	We developed a detailed description of each element of the rule, and conducted an engineering analysis of the expected impacts of the rule on mine operations.
Compliance costs and changes in industry behavior in response to the rule will vary by mine type and location, and according to site-specific conditions.	Because the industry is heterogeneous, we forecast impacts at 13 model mines across the U.S. to provide a representational understanding of the changes actual mines may face. In doing so, the analysis provides an overall measure of the scope and scale of potential changes under each alternative, but is not likely to be accurate with regard to any specific mining operation. Specific to longwall operations, OSMRE is conducting an additional analysis of potential impacts, and has requested comment on this issue in the Proposed Rule.
When compliance costs will be incurred by industry and SRAs is not known with certainty.	We estimate that all coal production after 2020 will be produced in compliance with the Proposed Rule. This is likely to be conservative, since some coal production will be grandfathered.
Future coal demand is not known with certainty.	Three baseline coal demand scenarios are estimated. In addition to the most likely to occur scenario, "high coal demand" and "low coal demand" scenarios are conducted.
Future coal supply is not known with certainty.	The method for forecasting future coal production is detailed in Chapter 5 of this analysis. The resulting forecast is compared against other published coal forecasts (specifically, EIA).
Whether or not the Proposed Rule will result in permitting delays is unknown.	The analysis qualitatively discusses the potential for the Proposed Rule to result in additional permit delays. OSMRE has asked for public comment on this issue.
Estimates of the future benefits of this rule rely on assumptions about industry behavior, market conditions, and site-specific conditions.	The model mines analysis is used in each coal region to arrive at quantified estimates of the impacts of the rule in terms of reducing the number of degraded stream miles, increasing the number of forested acres protected or restored, and reducing air emissions from mining operations. A number of other benefit categories are described qualitatively.
Future regulatory initiatives that could impact the industry are not known.	The analysis identifies existing and potential environmental regulations that are expected to influence mining practices / coal demand and legislative initiatives to reduce greenhouse gas emissions.
The impacts of changes in the cost of coal production will likely influence demand for natural gas and other substitute fuels. Similarly, changes in air pollutant emissions due to a reduction in coal burning at power plants and associated changes in carbon emissions from the electric utility industry are not calculated.	It is beyond the scope of this analysis to understand the environmental costs or benefits that may be associated with switching to an alternative fuel than coal, such as natural gas, that may occur due to changes in coal demand associated with this rule. We also do not capture potential offsetting changes in employment demand that could be associated with increased demand for alternative fuels that could occur.

CHAPTER 4 | COMPLIANCE COST ANALYSIS

This chapter describes the approaches we used to forecast compliance costs associated with the Proposed Rule, including assumptions made within those approaches. It also provides a summary of forecast compliance costs, both by region and industry-wide. This information is provided to detail the likely cost impacts of the Proposed Rule on both industry and State Regulatory Authorities (SRA).

4.1 INTRODUCTION AND SUMMARY OF RESULTS

Depending on the alternative selected, the Proposed Rule has the potential to result in increased administrative costs to the coal mining industry and SRAs, increased operational costs for coal mining entities, the "stranding" of coal reserves in areas where it may no longer be viable to mine under the new rules[101] shifts in the geographic distribution of coal production due to changes in the relative cost of coal production, and changes in the total quantity of coal produced.

This cost analysis estimates the incremental administrative and operational costs anticipated to result from the Proposed Rule (i.e., the changes in these costs expected due to the Proposed Rule over and above baseline costs that would be incurred in the absence of the rule). In this chapter we present our cost method, as well as a summary of the forecast compliance costs under the Proposed Rule. For information on compliance costs under the other Alternatives, please see Chapter 8.

Under the Proposed Rule, annualized costs are expected to be $52 million (discounted at a rate of seven percent). These anticipated incremental costs relative to the baseline would have represented approximately 0.1 percent of 2013 coal revenues. As is shown in Exhibit 4-2, forecast compliance costs vary significantly between regions and by mine type.

The sections that follow discuss the method behind our cost model and provide more detailed findings.

[101] See Chapter 3 for discussion of stranded reserves.

EXHIBIT 4-1. TOTAL FORECAST COAL PRODUCTION UNDER PROPOSED RULE (MILLIONS OF TONS)

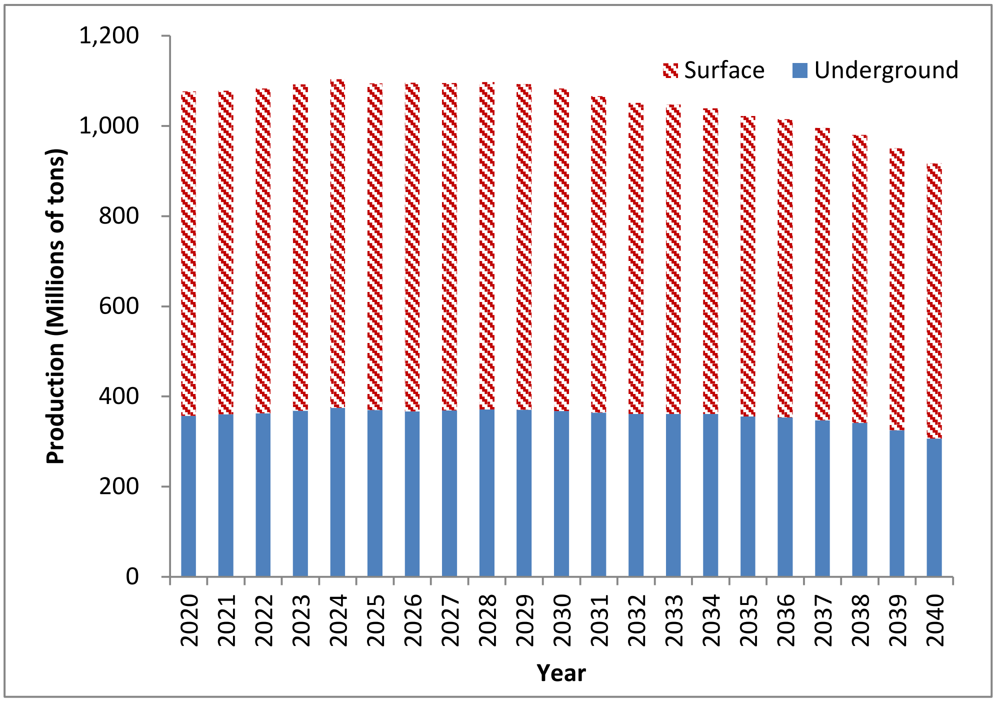


EXHIBIT 4-2. INDUSTRY AND GOVERNMENT ANNUALIZED COMPLIANCE COSTS UNDER PROPOSED RULE, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachia	$17,000,000	$6,700,000	$24,000,000
Colorado Plateau	$2,500,000	$200,000	$2,700,000
Gulf Coast	$6,200,000	N/A	$6,200,000
Illinois Basin	$14,000,000	$270,000	$14,000,000
Northern Rocky Mountains	$4,800,000	N/A	$4,800,000
Northwest	$98,000	N/A	$98,000
Western Interior	$550,000	$530	$550,000
Total U.S. Compliance Cost Impacts - All Mines	**$45,000,000**	**$7,100,000**	**$52,000,000**
Note: Totals may not sum due to rounding.			

4.2 COMPLIANCE COST METHOD

To develop an estimate of the total compliance costs of the rule, we estimate the expected increase in operational and administrative costs for each of the thirteen model mines (as detailed in Appendix B). We then convert these costs to costs per ton of coal produced. We then aggregate costs per ton using our forecast of future coal production over the timeframe for this analysis (2020 to 2040).

In regions with multiple surface or underground model mines (i.e. Appalachian Basin and the Illinois Basin), 2013 coal production data for active mines provided by MSHA is used to generate weighted regional compliance cost estimates.[102] Specifically:

- Compliance costs for the Central Appalachian surface area model mine are assumed to be representative of costs for mines in Central and Southern Appalachia with annual production greater than 1,000,000 tons, which constitute approximately 29 percent of regional production;
- Compliance costs for the Central Appalachian surface contour model mine are assumed to be representative of costs for remaining Central and Southern Appalachian surface mine production (45 percent of regional production);
- Compliance costs for the Northern Appalachian surface model mines are assumed to be representative of the surface mining within the Northern Appalachia (26 percent of total regional production); and
- Longwall mining is estimated to comprise 61 percent of underground mining in Appalachia; 29 percent in the Illinois Basin.

The sections below detail the method behind both operational and administrative cost calculations.

OPERATIONAL COST METHOD

As outlined in Chapter 2, coal mining operations vary substantially from region to region, within a region, and even within a mining type in a given region. Thus, we employ a model mines analysis to determine the likely changes that will be made by mine operators in response to the Proposed Rule. For a specific discussion and method used in the model mines analysis, see Appendix B.

Increased operational costs related to the Proposed Rule primarily include the following:

- Haulage costs – haulage costs are associated with moving mine spoils; these costs vary based on the requirements of each alternative, and only apply where valley fills occur;
- Stream restoration costs – the costs of returning to form and/or function streams disturbed due to mining;

[102] MSHA. 2013b. MSHA Annual Coal Production Data 2013. Provided by OSMRE July 24, 2014.

- Stream enhancement costs – the costs of mitigating any adverse effects to streams as required under each regulatory alternative, for fish and wildlife enhancement, including mitigation; and,
- Reforestation/PMLU costs – costs associated with reforesting or return to pre-mining land use (PMLU) requirements.

Exhibit 4-3 presents specific operational cost assumptions by model mine. For each model mine site, the engineers considered the topography, geology, hydrology, equipment needs, strip ratios, and other site-specific conditions to determine the most appropriate and likely industry response to the new regulations. The engineers used their expertise in applying industry standards and best practices, including consideration of site stability and safety considerations, to select the most appropriate actions and associated costs for each model mine. Recognizing that assumptions in the engineering analysis are important to the overall results of the regulatory impact analysis, a number of sensitivity analyses were conducted related to specific assumptions. These sensitivity analyses are described in Appendix B, Part 6. Tested assumptions included assumptions related to hourly equipment costs for haulage costs, spoil handling percentage of overburden in haulage costs, per acre costs of reforestation in riparian zones, production levels and stripping ratios. OSM requests public comment on these assumptions.

EXHIBIT 4-3. SELECTED OPERATIONAL COST ASSUMPTIONS BY MODEL MINE AND ALTERNATIVE

REGION AND MINE TYPE	BASELINE	PROPOSED RULE
Central Appalachia–Surface Area	- Postmining land use is forestry	- Haulage of excess spoil required. - Average haul distance 7,000 feet. - Postmining land use is forestry. - $600 per linear foot restoration cost for intermittent and perennial streams. - $800 per linear foot stream enhancement cost. - Incremental haulage costs of $0.17 per ton for truck/dozer use.[1]
Central Appalachia–Surface Contour	- Postmining land use is forestry	- Haulage of excess spoil required. - Average haul distance 7,500 feet. - Postmining land use is forestry. - $600 per linear foot restoration cost for intermittent and perennial streams. - $800 per linear foot stream enhancement cost. - Incremental haulage costs of $0.82 per ton for truck/dozer use. [1]
Central Appalachia – Underground (R&P)	- Postmining land use is forestry	- Postmining land use and reforestation costs of $0.02 per ton of coal produced.
N. Appalachia – Underground (LW)	- Postmining land use is hayland/pasture	- Postmining land use and reforestation costs of $0.01 per ton of coal produced.
N. Appalachia- Surface	- Postmining land use is hayland/pasture	- Postmining land use is forestry.
Colorado Plateau- Underground (LW)	- Postmining land use is hayland/pasture	- Postmining land use and reforestation costs of $0.01 per ton of coal produced.
Colorado Plateau- Surface	- Hydrologically ephemeral streams with a one square mile drainage basin are classified as intermittent and are mined through	- All hydrologically ephemeral streams previously classified as intermittent are reclassified as ephemeral. - Topsoil salvage is required for large surface area for 3-foot topsoil thickness.
Illinois Basin- Underground (R&P)	- n/a	- No material changes in engineering requirements between the baseline and the Proposed Rule.
Illinois Basin- Underground (LW)	- n/a	- No material changes in engineering requirements between the baseline and the Proposed Rule.
Illinois Basin- Surface	- Spoil from initial boxcut minimally graded in postmining topographic configuration.	- Postmining land use and reforestation costs of $0.01 per ton of coal produced in riparian corridor. - Topsoil salvage already required in this region.
Gulf Coast- Surface	- Postmining land use is forestry, as is common practice in region - Hydrologically ephemeral streams with a one square mile drainage basin are classified as intermittent and are mined through	- All hydrologically ephemeral streams previously classified as intermittent are reclassified as ephemeral. - Topsoil salvage is required for large surface area for 3-foot topsoil thickness.

REGION AND MINE TYPE	BASELINE	PROPOSED RULE
Northern Rocky Mountain & Great Plains - Surface Area	- Hydrologically ephemeral streams with a one square mile or greater drainage basin are classified as intermittent and are mined through	- Extremely large coal reserve per mine. - All hydrologically ephemeral streams previously classified as intermittent are reclassified as ephemeral. - Topsoil salvage is required for large surface area for 2 feet topsoil thickness.
Western Interior – Surface	- n/a	- No specific model mine created for the Western Interior due to similarity to Illinois Basin, assumed to be similar to Illinois Basin Surface Mine.
Western Interior – Underground (R&P)	- n/a	- No specific model mine created for Western Interior due to similarity to Illinois Basin, assumed to be similar to Illinois Basin Underground Room and Pillar Mine.
Northwest- Surface	- Regrade is not landformed	- $235 per linear foot restoration cost for streams [1] - Average haul distance 7,000 feet.

Note: Cost estimates are described in detail in Appendix B. Recognizing that assumptions in the engineering analysis are important to the overall results of the regulatory impact analysis, a number of sensitivity analyses were conducted related to specific assumptions. These sensitivity analyses are described in Appendix B, Part 6. Tested assumptions included assumptions related to hourly equipment costs for haulage costs, spoil handling percentage of overburden in haulage costs, per acre costs of reforestation in riparian zones, production levels and stripping ratios. OSMRE requests public comment on these assumptions.

[1] Haulage costs are dependent on topography, size of permit, equipment, and mining ratio at a particular site.

ADMINISTRATIVE COST METHOD

For purposes of this analysis, administrative costs are defined as the industry and government costs associated with time spent on permitting activities and requirements as well as related material costs (e.g. digital elevation modeling software and biological sampling). OSMRE estimated administrative efforts expected to result from the Proposed Rule for purposes of meeting the requirements of the Paperwork Reduction Act (PRA). These efforts were calculated on an annual basis, per permit, for mine operators and SRAs, based on experience and collaboration with the state regulators. Because of OSMRE's experience and close ties with the SRA's, we use OSMRE estimates to inform the administrative costs calculated below. For more detailed information on OSMRE's effort calculations, please see the PRA prepared by OSMRE.

Administrative Assumptions in the PRA analysis

In order to comply with the PRA, OSMRE estimated the aggregate burden (in hours) for information collection for the Proposed Rule, along with associated wage rates for industry and government. Specifically, OSMRE calculated the number of hours needed to comply with each element of the rule by 30 CFR sections (please see Exhibit 4-4 for specific sections). Wage costs were then obtained from the Bureau of Labor Statistics (BLS) and burdened onto the wage costs using a rate of 1.4 on the salary for industry personnel and 1.5 for state employees.[103] OSMRE's Original calculations were developed to be "per permit," which we assume to reflect "per mine" efforts.

EXHIBIT 4-4. PROPOSED RULE SECTIONS UNDER REVISION THAT INVOLVE ADMINISTRATIVE EFFORTS

ELEMENT	30 CFR SECTION	DEFINITION
DEFINITION OF MATERIAL DAMAGE	774.15	Requires update of PHC determination as part of permit renewal application. Regulatory authority must review monitoring results and reevaluate the adequacy of the CHIA as part of the permit renewal application review process.
	779.24/ 783.24	Requires mapping of public water supplies, wellhead protection zones, and any mine-water pumping facilities within permit and adjacent areas.
	780.21/ 784.21	Requires expanded CHIA findings and adds requirement for establishment of corrective action thresholds for parameters of concern.
	780.22/ 784.22	Contains new requirements for information on alternative water resources with respect to protected water supplies.
	780.23/ 784.23	Requires regulatory authority to reconsider the adequacy of the proposed monitoring plan after review of the permit application and preparation of the CHIA.
	780.29/ 784.29	Adds requirements for surface-water runoff control plan and inspection and reporting program.
	800.18	Adds new requirements to address bond and financial assurance needs to guarantee treatment of pollutional discharges requiring long-term treatment.
	816.34/ 817.34	Adds an inspection reporting requirements pertaining to storm water runoff control.
	816.41/ 817.41	This proposed section would add three new requirements that must be met before the regulatory authority may approve a proposed discharge to an underground mine.
BASELINE DATE COLLECTION	780.19/ 784.19	Requires additional baseline data for hydrology and aquatic biology.
MONITORING DURING MINING AND RECLAMATION	800.40	Adds new bond release application requirements.
	816.35-37/ 817.35-37	Establishes new requirements for surface, groundwater and biological monitoring.
MINING THROUGH STREAMS	780.12	Defined and counted under revegetation, topsoil management and reforestation element
	780.37/ 784.37	Requires explanation of why stream crossings are needed for roads and how they comply with other requirements.
ACTIVITIES IN OR NEAR STREAMS (INCLUDING EXCESS SPOIL AND COAL REFUSE)	816.71/ 817.71	Requires daily inspection log of excess spoil disposal facilities.

[103] BLS (Bureau of Labor Statistics). 2014a. Occupational Employment Statistics: May 2013 National Industry Specific Occupational Employment and Wage Estimates. United States Department of Labor. http://www.bls.gov/oes/2013/may/oes_nat.htm; BLS. 2014b. Employer Costs for Employee Compensation March - 2014. United States Department of Labor. http://www.bls.gov/news.release/archives/ecec_06112014.pdf

ELEMENT	30 CFR SECTION	DEFINITION
	780.28/ 784.28	Requires additional information and demonstrations when an applicant proposes to conduct operations adjacent to (within 100 feet), within, or through an intermittent or perennial stream.
REVEGETATION, TOPSOIL MANAGEMENT AND REFORESTATION	779.19/ 783.19	Requires the applicant to identify, describe, and map existing vegetation and plant communities as well as those plant communities that would exist under conditions of natural succession
	780.12/ 784.12	Requires detailed soil handling, revegetation and stream restoration plans.
	780.24/ 784.24	Adds new demonstration and approval requirements for alternative postmining land uses.
FISH AND WILDLIFE PROTECTION AND ENHANCEMENT	779.20/ 783.20	Requires site specific enhancement measures. Regulatory authority must document disposition of all U.S. Fish and Wildlife Service comments on threatened and endangered species elements of the permit application.

An estimate of the total annual materials costs were also developed by OSMRE. This cost estimate included (a) total capital and start-up costs and (b) total operation and maintenance and purchase of services components. Capital and start-up costs include, among other items, computers and software; monitoring, sampling, drilling and testing equipment; and record storage facilities. The cost of purchasing or contracting out information collection services was also included in this cost burden estimate.

Using the labor hour, wage cost, and non-wage cost estimates derived by OSMRE for both industry and SRAs, we calculated the total administrative cost burden. Specifically, we used the following steps:

1. Labor hours were multiplied by hourly wage rates to calculate total labor costs per permit;
2. Materials costs were then added to total labor costs;
3. Total labor costs and material burden costs for each 30 CFR section described in Exhibit 4-4 were assigned to underground mines (UG), surface mines (SM), or both (B);
4. Total labor costs and material costs were determined to be either one-time or recurring costs under relevant 30 CFR sections;
5. By 30 CFR section, we summed all one-time SM costs, all one-time UG costs, all recurring SM costs, and all recurring UG costs in order to obtain total one-time and recurring costs per SM and UG mine; and
6. Costs were calculated over the life of the model mine and then converted to per ton costs.

Industry and government administrative costs are summarized in Exhibits 4-5 and 4-6.

EXHIBIT 4-5. PER PERMIT ADMINISTRATIVE INDUSTRY COST OF THE PROPOSED RULE BY ELEMENT

ELEMENTS	MINE TYPE	HOURS	LABOR COSTS (HOURS X WAGE)[1]	MATERIALS COSTS (NON-WAGE COSTS)	TOTAL ONE-TIME COST	TOTAL RECURRING COSTS
Definition of Material Damage to the Hydrologic Balance	SM	16	$853[2]	$3,000[a]	$2,746	$1,107
	UG	16	$853[2]	$3,000[a]	$2,746	$1,107
Baseline Data Collection and Analysis	SM	36	$1,919	$19,670	$21,589	$0
	UG	36	$1,919	$19,670	$21,589	$0
Monitoring During Mining and Reclamation	SM	36	$1,919[2]	$4,550[a]	$0	$6,469
	UG	36	$1,919[2]	$4,550[a]	$0	$6,469
Mining Through Stream	SM	2	$107	$650	$757	$0
	UG	4	$213	$250	$463	$0
Activities In or Near Streams, Including Excess Spoil and Coal Refuse	SM	397	$21,164[2]	$0	$1,706	$19,458
	UG	375	$19,991[2]	$0	$533	$19,458
Revegetation, Topsoil Management, and Reforestation	SM	22	$1,173	$4,650	$5,823	$0
	UG	22	$1,173	$4,650	$5,823	$0
Fish and Wildlife Protection and Enhancement	SM	8	$426	$0	$426	$0
	UG	8	$426	$0	$426	$0
Total Industry Administrative Cost (Surface)[3]					$33,047	$27,034
Total Industry Administrative Cost (Underground)[3]					$31,581	$27,034

Notes:
[1] Wage rate calculated at $53.31 per hour.
[2] Denotes a portion of costs are expected to be recurring (i.e., borne annually) for life of the mine.
[3] Not all costs apply to all mines in all regions.

EXHIBIT 4-6. PER PERMIT ADMINISTRATIVE GOVERNMENT COST OF THE PROPOSED RULE BY ELEMENT

ELEMENT	MINE TYPE	HOURS	LABOR COSTS (HOURS X WAGE)[1]	TOTAL COST
Definition of Material Damage to the Hydrologic Balance	SM	20.5	$1,001	$1,001
	UG	20.5	$1,001	$1,001
Baseline Data Collection and Analysis	SM	8	$390	$390
	UG	8	$390	$390
Mining Through Stream	SM	5.5	$268	$268
	UG	.5	$24	$24
Activities In or Near Streams, Including Excess Spoil and Coal Refuse	SM	11	$537	$537
	UG	6	$293	$293
Revegetation, Topsoil Management, and Reforestation	SM	16	$781	$781
	UG	6.5	$317	$317
Fish and Wildlife Protection and Enhancement	SM	2	$98	$98
	UG	2	$98	$98
Total Industry Administrative Cost (Surface)[2]			$3,075	$3,075
Total Industry Administrative Cost (Underground)[2]			$2,123	$2,123

Notes:
[1] Wage rate calculated at $48.81 per hour.
[2] Not all costs apply to all mines in all regions.

Adapting Compliance Costs to Model Mines

After calculating administrative costs for both industry and SRAs on a per permit basis, we then removed costs associated with elements that were not relevant to particular regional mines. That is, not all mines are expected to incur all cost components. We note that this effort did not substantively change the outcome of the estimated compliance costs per ton of coal produced.

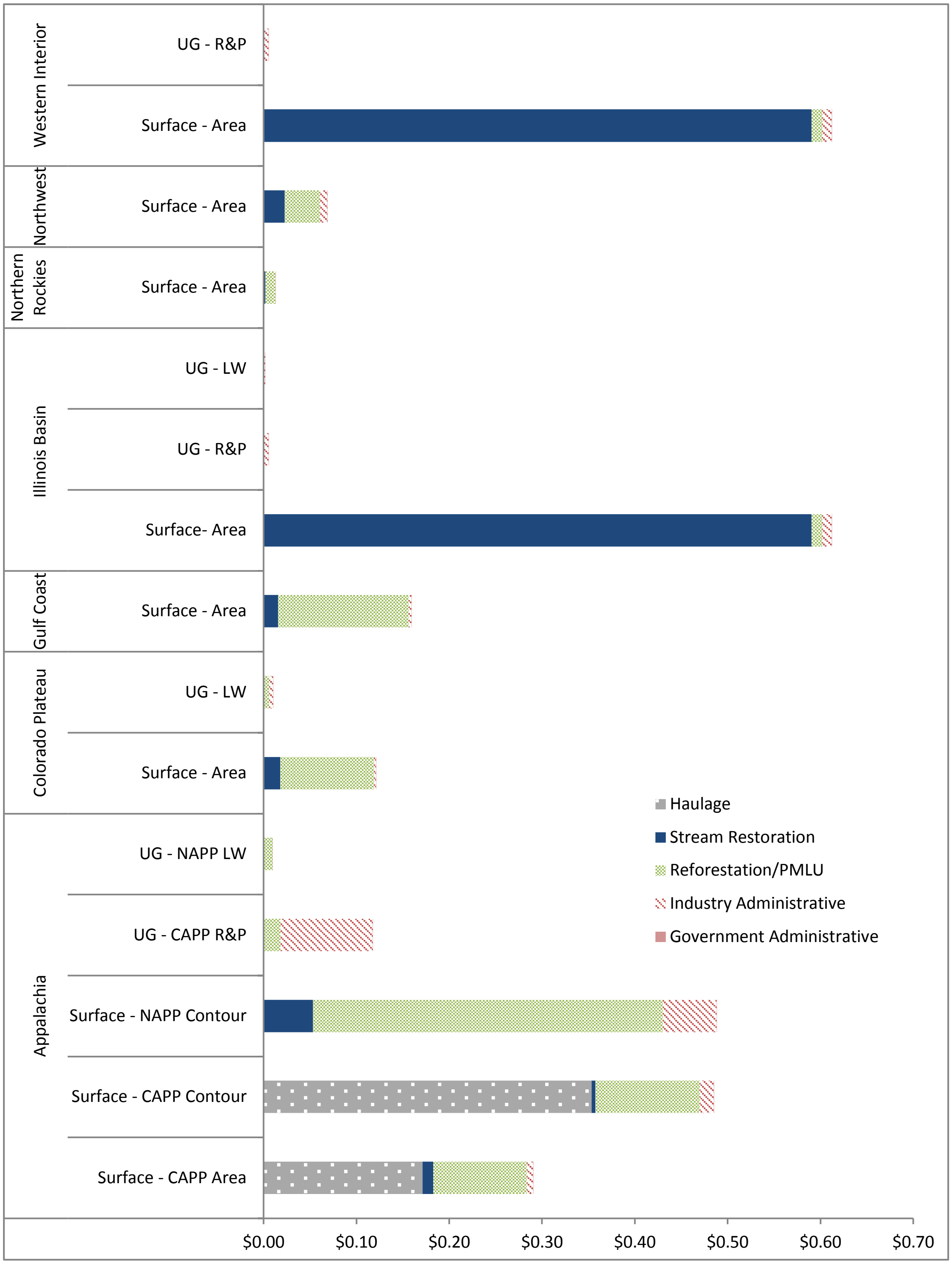
The results are total costs per ton by mine type and region. As explained above, for the Appalachian Basin surface and underground mines, and Illinois Basin underground mines, a weighted average is calculated to generate regional mine type costs. Exhibit 4-7 describes the percent of total compliance costs by cost category for each region and model mine. As shown:

- Central Appalachian Basin surface area mining incurs costs primarily related to increased haulage costs, with some costs related to reforestation, stream restoration, and industry administrative costs;
- Central Appalachian Basin surface contour mines are forecast to incur costs primarily related to haulage as well as some reforestation stream restoration, and industry administrative costs;
- Illinois Basin and Western Interior surface mines are forecast to see cost increases primarily related to stream restoration costs; We note that while costs are highest on the basis of costs per ton in these mines, the overall production of this mine type at the national scale is relatively modest;
- Northern Rocky Mountain, Colorado Plateau, and Gulf Coast surface mining operations are forecast to incur costs that primarily stem from increased reforestation costs as well as some stream restoration costs;
- Northwest surface mining operations are forecast to see costs primarily related to reforestation and stream restoration as well as some industry administrative requirements;
- Northern Appalachian Basin surface contour mines are forecast to incur costs primarily related to reforestation as well as some stream restoration and industry administrative costs;
- Compliance costs anticipated for underground mining activities in all regions are related to increased reforestation costs and the administrative requirements of the rule. Central Appalachian Basin underground room and pillar mines are forecast to see costs primarily related to industry administrative costs as well as some reforestation costs. Northern Appalachian Basin and Colorado Plateau underground longwall mines are forecast to incur costs primarily related to reforestation, with a smaller percentage coming from administrative requirements. Illinois Basin and Western Interior underground mining operations are forecast to incur costs entirely from additional administrative costs.

EXHIBIT 4-7. PERCENTAGE OF INCREASED COMPLIANCE COSTS BY COST CATEGORY PER MODEL MINE

REGION	MINE	HAULAGE	STREAM RESTORATION	REFORESTATION	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE
Appalachia	Central – Surface Area	59%	4%	35%	2%	0%
	Central – Surface Contour	73%	1%	23%	3%	0%
	Northern - Surface Contour	0%	11%	77%	12%	0%
	Central – Room & Pillar	0%	0%	15%	84%	0%
	Northern – Longwall	0%	0%	99%	0%	1%
Colorado Plateau	Surface Area	0%	15%	84%	2%	0%
	Longwall	0%	0%	60%	40%	0%
Gulf Coast	Surface Area	0%	10%	88%	2%	0%
	Surface Area	0%	96%	2%	2%	0%
Illinois Basin	Room & Pillar	0%	0%	0%	99%	1%
	Longwall	0%	0%	0%	97%	3%
Northern Rocky Mountains and Great Plains	Surface Area	0%	13%	85%	1%	1%
Northwest	Surface Area	0%	33%	55%	12%	0%
Western Interior	Surface Area	0%	96%	2%	2%	0%
	Room and Pillar	0%	0%	0%	99%	1%

EXHIBIT 4-8. INCREASED COMPLIANCE COSTS PER TON



Notes:

The model developed for Illinois Basin surface and room and pillar underground mines were also used to evaluate impacts to the Western Interior mining activities.

4.3 IMPACTS OF THE RULE ON COAL PRODUCTION

As discussed elsewhere in this report, changes in operational and administrative costs are expected to lead to changes in the price of coal produced. Increased coal prices are expected to influence the demand for coal, the regional distribution of coal production, and the total tonnage of coal produced by various mine types. This section summarizes the results of the coal market modeling efforts used in this analysis (see Appendix F for more detail). These results are presented here to illustrate the trends in anticipated coal production both before and after rule implementation. The Proposed Rule forecast production levels are also used to calculate the total compliance costs associated with the rule, both to industry and government entities.

As shown in Exhibits 4-9 and 4-10, under the baseline (i.e., in the absence of the rule), our model shows that the total tonnage of coal produced from surface mining operations is forecast to decline, primarily in the Appalachian Basin. The anticipated decline results from the relatively high production costs of Appalachian coal and market acceptability of other coal types (see Appendix F). Over the time period of this analysis, Appalachian surface mining is expected to decline from 58.3 million tons to 46.7 million tons of production, under the baseline. Under the Proposed Rule, underground mining activity is expected to increase slightly by 2025 but then decrease by 2040, with the increase in production driven by both the Appalachian Basin and Illinois Basin (see Exhibits 4-11 and 4-12). As shown in Exhibit 4-12, Illinois Basin is expected to see a decrease in underground production from 131 million tons to approximately 126 million tons over the time period of this analysis. We do not anticipate any significant impacts on highwall mining from the SPR. While highwall mining could occur under a stream, the recovery factor is typically lower than underground mining and the risk of subsidence is less than for underground mining. As such, highwall mining is not addressed further in this analysis.

For this analysis, compliance costs associated with implementation of the Proposed Rule developed in this chapter are entered into a coal market model to examine industry-level effects of the rule. The market model of forecast coal production is then used in this chapter to calculate total compliance costs to both industry and government. The detailed assumptions and results of this forecast are described in Appendix F.

EXHIBIT 4-9. BASELINE SURFACE COAL PRODUCTION BY REGION, 2020-2040 (MILLIONS OF TONS)

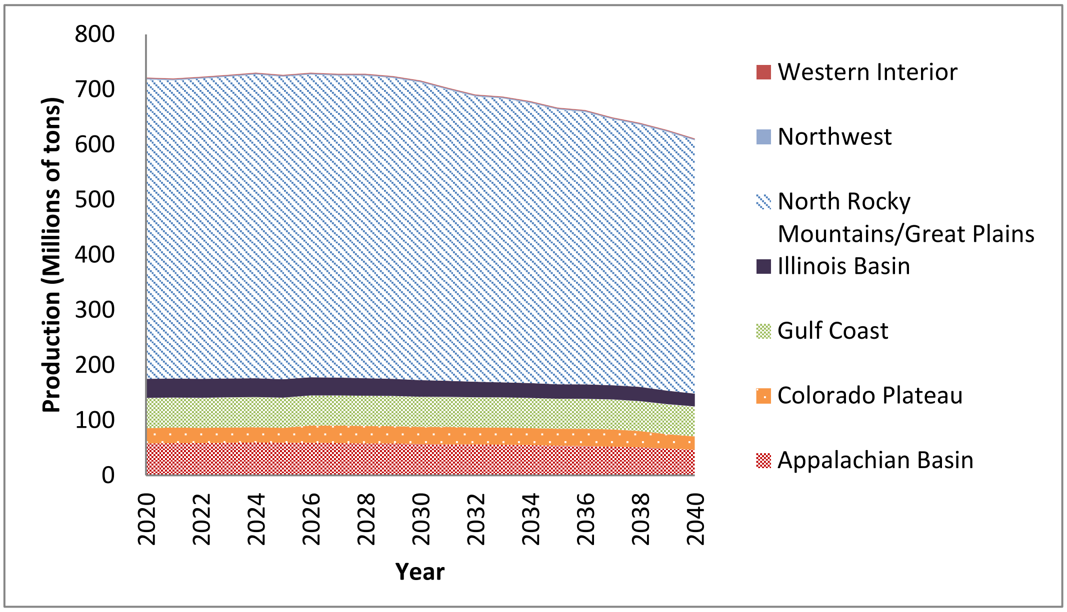


EXHIBIT 4-10. BASELINE SURFACE COAL PRODUCTION BY REGION, 2020-2040 (MILLIONS OF TONS)

REGION	2020	2025	2030	2035	2040
Appalachian Basin	58.3	59.2	57.2	53.8	46.7
Colorado Plateau	27.8	27.5	31.1	31.1	24.4
Gulf Coast	54.3	54.4	54.3	54.1	54.0
Illinois Basin	34.9	33.4	30.5	26.4	23.4
Northern Rocky Mountains and Great Plains	542.7	548.6	539.8	498.2	459.2
Northwest	2.0	2.0	2.0	2.0	2.0
Western Interior	1.3	1.3	1.3	1.2	1.2
Total	**721.4**	**726.3**	**716.1**	**666.9**	**610.9**
Note: For comparison, EIA reports 2012 UG production totals as approximately 673 million short tons. (EIA Annual Coal Report 2012, Published December 12, 2013. Table 7 http://www.eia.gov/coal/annual/pdf/acr.pdf)					

EXHIBIT 4-11. BASELINE UNDERGROUND COAL PRODUCTION BY REGION, 2020-2040 (MILLIONS OF TONS)

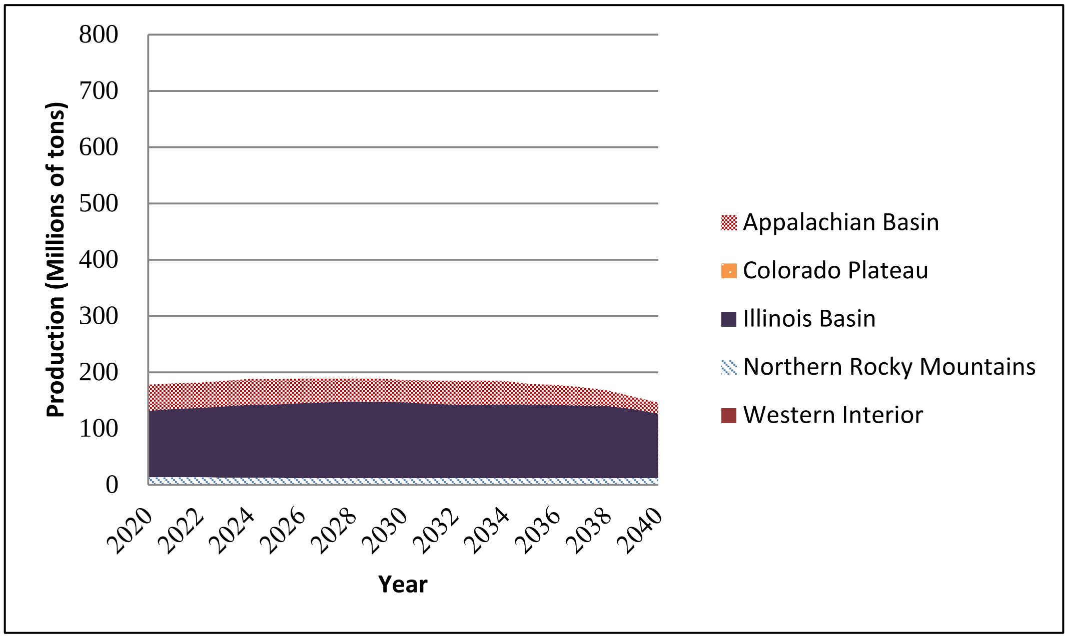


EXHIBIT 4-12. BASELINE UNDERGROUND COAL PRODUCTION BY REGION, 2020-2040 (MILLIONS OF TONS)

REGION	2020	2025	2030	2035	2040
Appalachian Basin	177.8	187.2	186.4	179.1	146.0
Colorado Plateau	35.5	29.8	24.1	23.0	22.8
Gulf Coast	0.0	0.0	0.0	0.0	0.0
Illinois Basin	131.3	142.5	146.5	142.3	126.3
Northern Rocky Mountains and Great Plains	13.1	11.6	11.3	11.2	11.1
Northwest	0.0	0.0	0.0	0.0	0.0
Western Interior	0.1	0.1	0.1	0.1	0.1
Total	**357.9**	**371.2**	**368.5**	**355.7**	**306.3**
Note: For comparison, EIA reports 2012 UG production totals as approximately 342 million short tons (EIA. 2013a).					

Our model anticipates that coal production will decrease in aggregate under the rule by approximately 0.2 percent in response to increased costs of producing coal when compared with production expected under the baseline. On average, total annual production is expected to decrease by about 1.9 million tons, as shown in Exhibit 4-13. As part of this change, a decrease in overall surface production (approximately 0.1 percent) is anticipated, which is made relatively more expensive by this rule.

The decline is largely a result of a decrease in surface mining production in the Appalachian Basin. The analysis also suggests that underground coal production in Appalachia will decrease by 0.3 percent as a result of the Proposed Rule relative to baseline forecast production. Exhibits 4-13 through 4-17 summarize the results of the coal market forecast analysis under the Proposed Rule. Exhibit 4-13 shows the average annual coal production by region and mine type under the Proposed Rule relative to the baseline. Exhibits 4-14 and 4-15 present surface and underground production forecasts under the Proposed Rule for selected years. Exhibits 4-16A, 4-16B and 4-17 summarize the changes in coal production under the Proposed Rule.

In other areas, such as the Illinois Basin, production is expected to decrease relative to baseline forecast production, but the magnitude of the expected change due to the Proposed Rule is not as large as in the Appalachian Basin. In the Illinois Basin, increased coal prices due to the rule lead to decreased coal demand from coal-fired power plants. As noted above, we do not anticipate any significant impacts on highwall mining from the SPR.

EXHIBIT 4-13. AVERAGE ANNUAL COAL PRODUCTION CHANGE FORECAST BY REGION AND MINE TYPE UNDER THE PROPOSED RULE RELATIVE TO BASELINE (MILLIONS OF TONS)

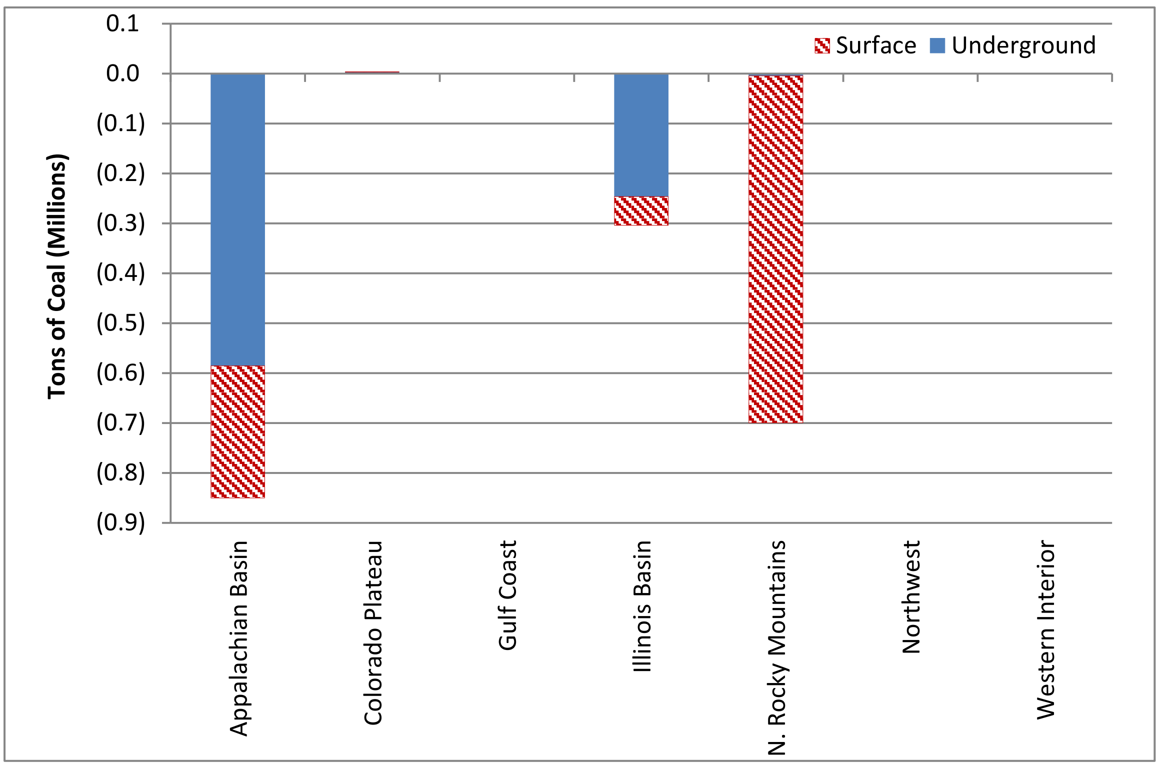


EXHIBIT 4-14. SURFACE COAL PRODUCTION FORECAST BY REGION UNDER PROPOSED RULE, 2020-2040 (MILLIONS OF TONS)

REGION	2020	2025	2030	2035	2040
Appalachian Basin	58.1	58.7	56.9	53.7	46.6
Colorado Plateau	27.8	27.5	31.1	31.1	24.4
Gulf Coast	54.3	54.4	54.3	54.2	54.0
Illinois Basin	34.8	33.3	30.4	26.4	23.4
Northern Rocky Mountains and Great Plains	541.7	547.5	539.2	498.0	459.2
Northwest	2.0	2.0	2.0	2.0	2.0
Western Interior	1.3	1.3	1.3	1.2	1.2
Total	**720.0**	**724.7**	**715.2**	**666.5**	**610.8**

EXHIBIT 4-15. UNDERGROUND COAL PRODUCTION FORECAST BY REGION UNDER PROPOSED RULE, 2020-2040 (MILLIONS OF TONS)

REGION	2020	2025	2030	2035	2040
Appalachian Basin	177.3	186.1	185.8	178.8	145.9
Colorado Plateau	35.5	29.8	24.1	23.0	22.8
Gulf Coast	0.0	0.0	0.0	0.0	0.0
Illinois Basin	130.8	142.1	146.4	142.2	126.63
Northern Rocky Mountains and Great Plains	13.1	11.6	11.3	11.2	11.1
Northwest	0.0	0.0	0.0	0.0	0.0
Western Interior	0.1	0.1	0.1	0.1	0.1
Total	**356.9**	**369.8**	**367.7**	**355.4**	**306.2**

EXHIBIT 4-16A. ANNUAL CHANGES IN COAL PRODUCTION UNDER THE PROPOSED RULE RELATIVE TO BASELINE (MILLIONS OF TONS)

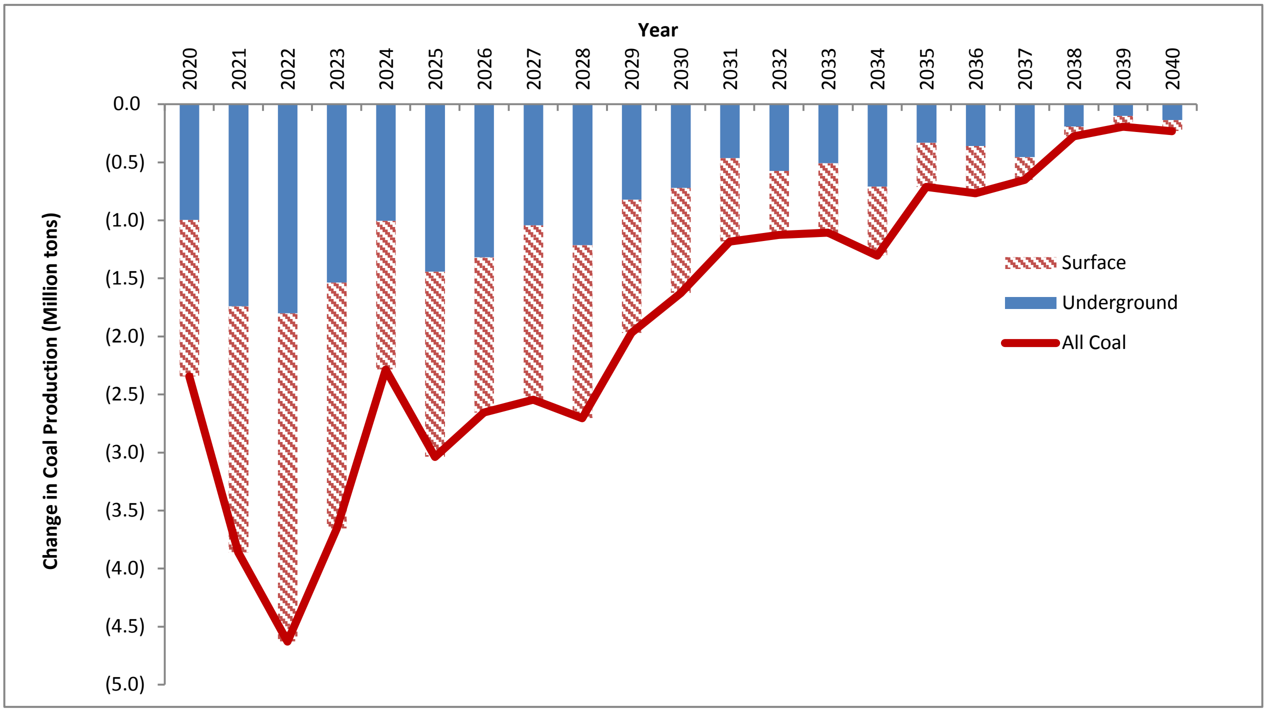
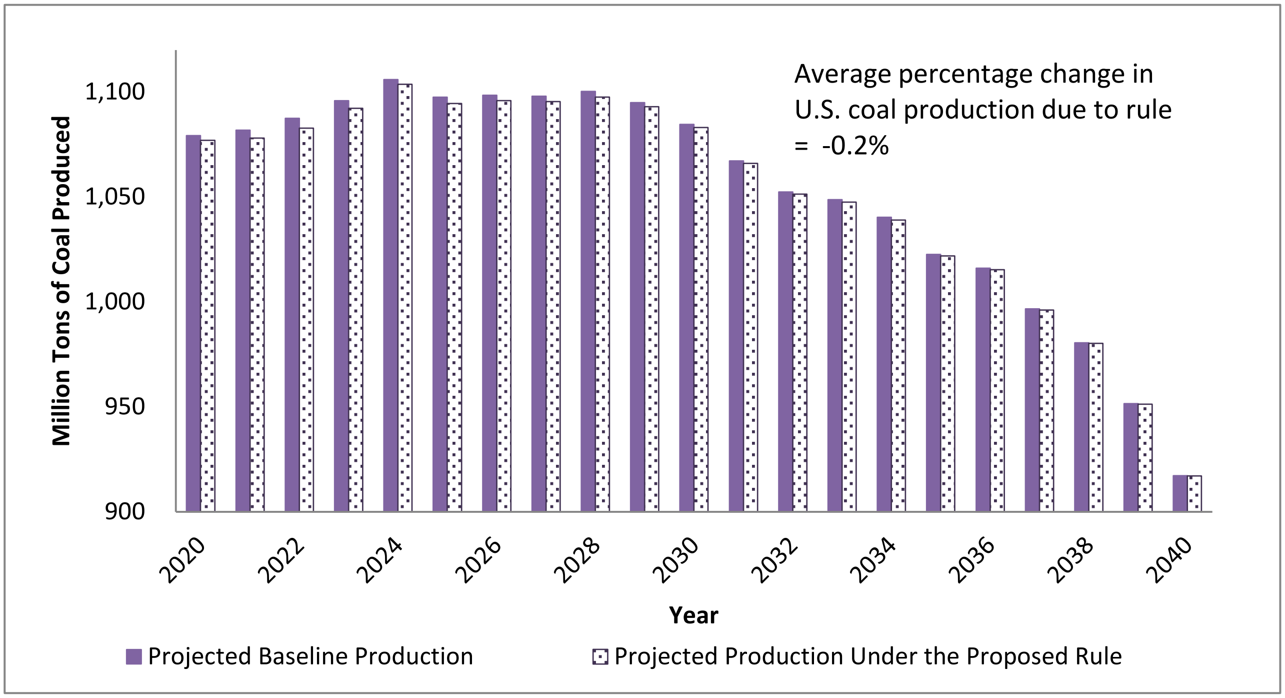


EXHIBIT 4-16B. ANNUAL COAL PRODUCTION UNDER BASELINE CONDITIONS AND THE PROPOSED RULE, 2020-2040 (MILLIONS OF TONS)



Note: Baseline forecast coal production, absent the Proposed Rule, shows a decrease in national coal production of 162 million tons between 2020 and 2040, representing a 15 percent decrease during the study period for our analysis. The annual reduction in tons of coal produced due to the Proposed Rule ranges from a decrease of 4.6 million tons in 2022 to a decrease of 0.2 million tons in 2039, with an average annual decrease of 1.9 million tons compared to forecast baseline production. While the specific assumptions and results of the model can be debated, the direction of the resulting change, i.e., the impact of the rule is an increase in cost that results in decreased coal production, is robust.

EXHIBIT 4-17. SUMMARY OF COAL PRODUCTION FORECAST UNDER BASELINE AND PROPOSED RULE (MILLIONS OF TONS)

ALTERNATIVE	MINE TYPE	2020	2025	2030	2035	2040	ANNUAL AVERAGE (2020-2040)
Baseline	SM	721.4	726.3	716.1	666.9	610.9	694.7
	UG	357.9	371.2	368.5	355.7	306.3	358.5
	TOTAL	**1,079.3**	**1,097.5**	**1084.6**	**1,022.6**	**917.2**	**1,053.2**
Proposed Rule	SM	720.0	724.7	715.2	666.5	610.8	693.6
	UG	356.9	369.8	367.7	355.4	306.2	357.7
	TOTAL	**1,077.0**	**1,094.5**	**1,083.0**	**1,021.9**	**917.0**	**1,051.4**
Net Change due to Proposed Rule	SM	(1.3)	(1.3)	(0.9)	(0.4)	(0.1)	(1.0)
	UG	(1.0)	(1.3)	(0.7)	(0.3)	(0.1)	(0.8)
	TOTAL	**(2.3)**	**(2.7)**	**(1.6)**	**(0.7)**	**(0.2)**	**(1.9)**
Percent Change (%)	***SM***	***(0.2)***	***(0.2)***	***(0.1)***	***(0.1)***	***0***	***(0.1)***
	UG	***(0.3)***	***(0.4)***	***(0.2)***	***(0.1)***	***0***	***(0.2)***
	TOTAL	***(0.2)***	***(0.3)***	***(0.1)***	***(0.1)***	***0***	***(0.2)***

4.4 COMPLIANCE COST RESULTS

INDUSTRY OPERATIONAL COSTS

The impacts of the Propose Rule on costs to industry are anticipated to vary across mine type and region (as presented in Exhibits 4-18 and 4-19). Some general conclusions:

- Central Appalachian surface area mines are anticipated to experience cost increases ($0.28 per ton), primarily due to the increase in haulage and reforestation costs;
- Central Appalachia surface contour mines will experience cost increases ($0.45per ton), primarily associated with an increase in haulage and reforestation costs;
- Northern Appalachia surface mines are anticipated to experience cost increases ($0.43 per ton) primarily related to increased reforestation and PMLU costs;
- Colorado Plateau surface mines will experience cost increases ($0.12 per ton) primarily due to an increase in reforestation and PMLU costs;
- Gulf Coast surface mines will experience cost increases ($0.16 per ton) primarily due to an increase in reforestation and PMLU costs;
- Illinois Basin surface mines will experience cost increases ($0.60 per ton) primarily due to an increase in stream restoration costs;

- Northern Rocky Mountain and Great Plains surface mines are anticipated to experience cost increases ($0.01 per ton) associated with additional reforestation and PMLU costs;
- Northwest surface mines will experience cost increases ($0.06 per ton) primarily due to an increase in reforestation and PMLU and stream restoration costs;
- Western Interior surface mines will experience cost increases ($0.60 per ton) primarily associated with an increase in stream restoration costs;
- Central Appalachia underground room and pillar mines are anticipated to experience cost increases ($0.02 per ton) associated with additional reforestation costs;
- Northern Appalachia underground longwall mines will experience cost increases ($0.01 per ton) entirely from reforestation costs;
- Colorado Plateau underground longwall mines are expected to experience cost increases ($0.01 per ton) primarily associated with an increase in reforestation costs;
- Illinois Basin and Western Interior underground mines are not forecast to experience any cost increases under the Proposed Rule; and,
- Across the entire United States, annualized operational compliance costs associated with the Proposed Rule are estimated to be approximately $45,000,000.

EXHIBIT 4-18. INCREASE IN INDUSTRY OPERATIONAL COSTS UNDER THE PROPOSED RULE, (2014 DOLLARS)

REGION	MINE TYPE	INCREASED OPERATIONAL COSTS PER MINE	COAL PRODUCED PER MINE (MILLION TONS)	INCREASED OPERATIONAL COSTS (PER TON)
Appalachian Basin	Central – Surface Area[1]	$10,500,000	37.0	$0.28
	Central – Surface Contour[1]	$2,300,000	5.0	$0.45
	Northern - Surface Contour[1]	$690,000	1.6	$0.43
	Central – Room & Pillar[2]	$55,000	3.0	$0.02
	Northern – Longwall[2]	$660,000	69.3	$0.01
Colorado Plateau	Surface Area	$11,000,000	92.2	$0.12
	Longwall	$120,000	20.5	$0.01
Gulf Coast	Surface Area	$6,400,000	40.7	$0.16
	Surface Area	$7,500,000	12.4	$0.60
Illinois Basin	Room & Pillar[3]	$0	19.1	$0.00
	Longwall[3]	$0	106.0	$0.00
Northern Rocky Mountain and Great Plains	Surface Area	$13,000,000	1,056.2	$0.01
Northwest	Surface Area	$2,200,000	37.0	$0.06
Western Interior	Surface Area	$7,500,000	12.4	$0.60
	Room and Pillar	$0	19.1	$0.00

[1] These costs are weighted to provide an average cost for surface mines in Appalachia in Exhibit 4-19.
[2] These costs are weighted to provide an average cost for underground mines in Appalachia in Exhibit 4-19.
[3] These costs are weighted to provide an average cost for underground mines in Illinois Basin in Exhibit 4-19.

EXHIBIT 4-19. SUMMARY OF INCREASE IN INDUSTRY OPERATIONAL COSTS, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INCREASED OPERATIONAL COSTS PER TON	TOTAL COAL PRODUCTION, 2020-2040 (MILLIONS OF TONS)	TOTAL OPERATIONAL COSTS (ANNUALIZED)
Appalachia	Surface[1]	$0.40	1,170	$16,000,000
	UG[1]	$0.01	3,765	$1,670,000
Colorado Plateau	Surface	$0.12	622	$2,500,000
	UG	$0.01	551	$120,000
Gulf Coast	Surface	$0.16	1,141	$6,005,000
Illinois Basin	Surface	$0.60	630	$13,500,000
	UG[1]	$0.00	2,950	$0
Northern Rocky Mountains	Surface	$0.01	10,935	$4,710,000
Northwest	Surface	$0.06	42	$86,100
Western Interior	Surface	$0.60	26	$544,000
	UG	$0.00	3	$0
Total U.S. Industry Operational Cost Impact			**21,835**	**$45,200,000**

Note: Totals may not sum due to rounding.
[1] These costs are weighted to provide an average cost for mines in Appalachia. Specifically, compliance costs for the Central Appalachian surface area model mine are assumed to be representative of costs for mines in Central Appalachia with annual production greater than 1,000,000 tons (29 percent of regional production); compliance costs for the Central Appalachian surface contour model mine are assumed to be representative of costs for remaining Central Appalachian surface mine production (45 percent of regional production); and compliance costs for the Northern Appalachian surface model mines are assumed to be representative of the remaining portion of surface mining within the greater Appalachian Basin region (26 percent of total regional production). Longwall mining is assumed to comprise 61 percent of underground mining in Appalachia; 29 percent in the Illinois Basin.

INDUSTRY ADMINISTRATIVE COSTS

Forecast administrative results varied across model mine and region. In most cases, the added administrative costs per ton of coal produced added a very small amount to the overall burden of the rule. The administrative costs borne by surface mines are higher than for underground mines, and the regions experiencing the greatest cost per ton produced are Western Interior and Appalachia. As shown in Exhibit 4-20, on a cost per ton basis, the highest forecast administrative costs are expected to occur for Central Appalachia underground room and pillar mines; these costs are estimated to be $0.10 per ton. Exhibit 4-21 summarizes the results for the Industry Administrative cost analysis across coal regions by mine type.

EXHIBIT 4-20. INCREASE IN INDUSTRY ADMINISTRATIVE COSTS UNDER THE PROPOSED RULE, (2014 DOLLARS)

REGION	MINE TYPE	INCREASED ADMINISTRATIVE COSTS PER MINE	COAL PRODUCED PER MINE (MILLION TONS)	INCREASED ADMINISTRATIVE COSTS PER TON
Appalachian Basin	Central – Surface Area[1]	$260,000	37.0	$0.01
	Central – Surface Contour[1]	$180,000	5.0	$0.04
	Northern - Surface Contour[1]	$92,000	1.6	$0.06
	Central – Room & Pillar[2]	$300,000	3.0	$0.10
	Northern – Longwall[2]	$370,000	69.3	$0.00
Colorado Plateau	Surface Area	$190,000	92.2	$0.00
	Longwall	$83,000	20.5	$0.00
Gulf Coast	Surface Area	$130,000	40.7	$0.00
	Surface Area	$130,000	12.4	$0.01
Illinois Basin	Room & Pillar[3]	$100,000	19.1	$0.01
	Longwall[3]	$170,000	106.0	$0.00
Northern Rocky Mountain and Great Plains	Surface Area	$190,000	1,056.2	$0.00
Northwest	Surface Area	$300,000	37.0	$0.01
Western Interior	Surface Area	$130,000	12.4	$0.01
	Room and Pillar	$100,000	19.1	$0.01

[1] These costs are weighted to provide an average cost for surface mines in Appalachia in Exhibit 4-21.
[2] These costs are weighted to provide an average cost for underground mines in Appalachia in Exhibit 4-21.
[3] These costs are weighted to provide an average cost for underground mines in Illinois Basin in Exhibit 4-21.

EXHIBIT 4-21. SUMMARY OF INCREASE IN INDUSTRY ADMINISTRATIVE COSTS, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INCREASED ADMINISTRATIVE COSTS PER TON[1]	TOTAL COAL PRODUCTION, 2020-2040 (MILLIONS OF TONS)	TOTAL ADMINISTRATIVE COSTS (ANNUALIZED)
Appalachia	Surface[1]	$0.03	1,170	$1,300,000
	UG[1]	$0.04	3,765	$5,000,000
Colorado Plateau	Surface	$0.00	622	$43,000
	UG	$0.00	551	$80,000
Gulf Coast	Surface	$0.00	1,141	$120,000
Illinois Basin	Surface	$0.01	630	$230,000
	UG[1]	$0.00	2,950	$260,000
Northern Rocky Mountains	Surface	$0.00	10,935	$68,000
Northwest	Surface	$0.01	42	$11,000
Western Interior	Surface	$0.01	26	$9,200
	UG	$0.01	3	$530
Total U.S. Industry Administrative Cost Impact			**21,835**	**$7,100,000**

Note: Totals may not sum due to rounding.
[1] This is the weighted average cost for relevant mines. Refer to Exhibit 4-19 for weighting method.

GOVERNMENTAL REGULATORY COSTS

To calculate additional costs on government entities due to the Proposed Rule on SRAs, we followed the same steps used to aggregate the administrative costs across the coal industry. The additional annual costs of the rule to government agencies range from as low as $1,830 per mine for underground mining regulating agencies in Illinois Basin and the Western Interior, to as high as $2,546 per mine for surface area mining regulating agencies in Central Appalachia and in the Northwest. Exhibits 4-22 and 4-23 provide the results of the government administrative cost analysis.

TOTAL COMPLIANCE COST EFFECTS

Exhibit 4-24 presents the total compliance costs per ton of coal produced. Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculate the total compliance cost effects. These are provided in Exhibit 4-25.

EXHIBIT 4-22. INCREASE IN GOVERNMENTAL ADMINISTRATIVE COSTS UNDER THE PROPOSED RULE, (2014 DOLLARS)

REGION	MINE TYPE	INCREASED GOVERNMENT ADMINISTRATIVE COSTS PER MINE	COAL PRODUCED PER MINE (MILLION TONS)	INCREASED GOVERNMENT ADMINISTRATIVE COSTS (PER TON)
Appalachian Basin	Central – Surface Area[1]	$2,500	37.0	<$0.01
	Central – Surface Contour[1]	$2,500	5.0	<$0.01
	Northern - Surface Contour[1]	$2,500	1.6	<$0.01
	Central – Room & Pillar[2]	$2,100	3.0	<$0.01
	Northern – Longwall[2]	$2,100	69.3	<0.01
Colorado Plateau	Surface Area	$2,400	92.2	<$0.01
	Longwall	$1,800	20.5	<$0.01
Gulf Coast	Surface Area	$2,500	40.7	<$0.01
	Surface Area	$2,500	12.4	<$0.01
Illinois Basin	Room & Pillar[3]	$1,800	19.1	<$0.01
	Longwall[3]	$1,800	106.0	<$0.01
Northern Rocky Mountain and Great Plains	Surface Area	$2,400	1,056.2	<$0.01
Northwest	Surface Area	$2,500	37.0	<$0.01
Western Interior	Surface Area	$2,500	12.4	<$0.01
	Room and Pillar	$1,800	19.1	<$0.01

[1] These costs are weighted to provide an average cost for surface mines in Appalachia in Exhibit 4-23.
[2] These costs are weighted to provide an average cost for underground mines in Appalachia in Exhibit 4-23.
[3] These costs are weighted to provide an average cost for underground mines in Illinois Basin in Exhibit 4-23.

EXHIBIT 4-23. SUMMARY OF INCREASE IN GOVERNMENT ADMINISTRATIVE COSTS, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INCREASED GOVERNMENT COSTS PER TON	TOTAL COAL PRODUCTION, 2020-2040 (MILLIONS OF TONS)	TOTAL GOVERNMENT COSTS (ANNUALIZED)
Appalachia	Surface[1]	<$0.01	1,170	$2,800
	UG[1]	<$0.01	3,764	$7,200
Colorado Plateau	Surface	<$0.01	622	$1,300
	UG	<$0.01	551	$990
Gulf Coast	Surface	<$0.01	1,141	$2,600
Illinois Basin	Surface	<$0.01	630	$1,500
	UG[1]	<$0.01	2,950	$5,000
Northern Rocky Mountains and Great Plains	Surface	<$0.01	10,935	$24,200
Northwest	Surface	<$0.01	42	$98
Western Interior	Surface	<$0.01	27	$61
Western Interior	UG	<$0.01	3	$5
Total U.S. Government Administrative Cost Impact			**21,835**	**$46,000**

Note: Totals may not sum due to rounding.
[1] This is the weighted average cost for relevant mines. Refer to Exhibit 4-19 for weighting method.

EXHIBIT 4-24. SUMMARY OF TOTAL INDUSTRY AND GOVERNMENT COMPLIANCE COSTS OF THE PROPOSED RULE PER TON (2014 DOLLARS)

REGION	MINE TYPE	TOTAL INCREASED COSTS PER TON
Appalachia	Surface [1]	$0.43
	UG [1]	$0.05
Colorado Plateau	Surface	$0.12
	UG	$0.01
Gulf Coast	Surface	$0.16
Illinois Basin	Surface	$0.61
	UG [1]	$0.00
Northern Rocky Mountains and Great Plains	Surface	$0.01
Northwest	Surface	$0.07
Western Interior	Surface	$0.61
	UG	$0.01

[1] This is the weighted average cost for relevant mines. Refer to Exhibit 4-19 for weighting method.

EXHIBIT 4-25. SUMMARY OF TOTAL INDUSTRY AND GOVERNMENT COMPLIANCE COSTS OF THE PROPOSED RULE, ANNUALIZED, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS (ANNUALIZED)	INDUSTRY ADMINISTRATIVE COSTS (ANNUALIZED)	GOVERNMENT ADMINISTRATIVE COSTS (ANNUALIZED)	TOTAL COSTS (ANNUALIZED)
Appalachia	Surface	$16,000,000	$1,300,000	$2,800	$17,000,000
	UG	$1,700,000	$5,000,000	$7,200	$6,700,000
Colorado Plateau	Surface	$2,500,000	$43,000	$1,300	$2,500,000
	UG	$120,000	$80,000	$990	$200,000
Gulf Coast	Surface	$6,100,000	$120,000	$2,600	$6,200,000
Illinois Basin	Surface	$13,000,000	$230,000	$1,500	$14,000,000
	UG	$0	$260,000	$5,000	$270,000
Northern Rocky Mountains and Great Plains	Surface	$4,700,000	$68,000	$24,000	$4,800,000
Northwest	Surface	$86,000	$12,000	$98	$98,000
Western Interior	Surface	$540,000	$9,200	$61	$550,000
	UG	$0	$530	$5	$530
Total U.S. Compliance Cost Impacts	Surface	$43,000,000	$1,800,000	$33,000	$45,000,000
	UG	$1,800,000	$5,300,000	$13,000	$7,100,000
	TOTAL	**$45,000,000**	**$7,100,000**	**$46,000**	**$52,000,000**
Note: Totals may not sum due to rounding.					

ALTERNATIVE COAL DEMAND SCENARIOS

Due to the large number of variables inherent in forecasting future coal demand, we present annualized compliance costs for two additional baseline and Proposed Rule coal demand scenarios, representing "high coal demand" and "low coal demand" scenarios, which are further discussed in Chapter 5. Using the high coal demand scenario, annualized compliance costs would be expected to increase by approximately $2.3 million dollars relative to the expected base case coal demand scenario (a 4 percent increase over reported costs). Under the low coal demand scenario, compliance costs would decrease by approximately $6.8 million dollars relative to the base case coal demand scenario as less coal is produced (representing an 13 percent decrease below reported costs).

EXHIBIT 4-26. COMPLIANCE COSTS OF THE PROPOSED RULE UNDER ALTERNATIVE BASELINE SCENARIOS, ANNUALIZED, SEVEN PERCENT DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	COMPLIANCE COSTS (ANNUALIZED) LOW PRODUCTION SCENARIO	COMPLIANCE COSTS (ANNUALIZED) HIGH PRODUCTION SCENARIO
Appalachia	Surface	$16,000,000	$18,000,000
	UG	$6,100,000	$7,000,000
Colorado Plateau	Surface	$2,300,000	$2,600,000
	UG	$150,000	$220,000
Gulf Coast	Surface	$5,200,000	$6,200,000
Illinois Basin	Surface	$11,000,000	$14,000,000
	UG	$220,000	$280,000
Northern Rocky Mountains and Great Plains	Surface	$3,500,000	$4,900,000
Northwest	Surface	$98,000	$98,000
Western Interior	Surface	$490,000	$550,000
	UG	$473	$530
Total U.S. Compliance Cost Impacts	Surface	$39,000,000	$47,000,000
	UG	$6,400,000	$7,500,000
	TOTAL	**$46,000,000**	**$55,000,000**

4.5 LIMITATIONS AND UNCERTAINTIES

Exhibit 4-27 presents a summary of key uncertainties that affect cost estimates in this chapter.

EXHIBIT 4-27. TREATMENT OF KEY UNCERTAINTIES IN THE REGULATORY IMPACT ANALYSIS

UNCERTAINTY	TREATMENT OF UNCERTAINTY
Compliance costs and changes in industry behavior that will be associated with this rulemaking are not known with certainty.	We developed a detailed description of each element of the rule, and conducted an engineering analysis of the expected impacts of the rule on mine operations. Throughout the analysis, the engineers used their best judgment to select the most appropriate cost assumptions for each model mine. Recognizing that assumptions in the engineering analysis are important to the overall results of the regulatory impact analysis, a number of sensitivity analyses were conducted related to specific assumptions. These sensitivity analyses are described in Appendix B, Part 6. Tested assumptions included assumptions related to hourly equipment costs for haulage costs, spoil handling percentage of overburden in haulage costs, per acre costs of reforestation in riparian zones, production levels and stripping ratios. OSM requests public comment on these assumptions.
Compliance costs and changes in industry behavior in response to the rule will vary by mine type and location, and according to site-specific conditions.	Because the industry is heterogeneous, we forecast impacts at 13 model mines across the U.S. to provide a representational understanding of the changes actual mines may face. In doing so, the analysis provides an overall measure of the scope and scale of potential changes under each alternative, but is not likely to be accurate with regard to any specific mining operation. Potential impacts to longwall operations are addressed in Appendix D. Impacts to coal refuse facilities are described in Appendix E. OSM requests comment on model mine assumptions, including assumptions related to longwall mining and coal refuse issues.
When compliance costs will be incurred by industry and SRAs is not known with certainty.	We estimate that all coal production after 2020 will be produced in compliance with the Proposed Rule. This is likely to be conservative, since some coal production will be grandfathered.
Future coal demand is not known with certainty.	Three baseline coal demand scenarios are estimated. In addition to the most likely to occur scenario, "high coal demand" and "low coal demand" scenarios are conducted.
Future coal supply is not known with certainty.	The method for forecasting future coal production is detailed in Chapter 5 of this analysis. The resulting forecast is compared against other published coal forecasts (specifically, EIA).
Whether the Proposed Rule will result in permitting delays is unknown.	The analysis qualitatively discusses the potential for the Proposed Rule to result in additional permit delays. OSMRE has asked for public comment on this issue.
Future regulatory initiatives that could impact the industry are not known.	The analysis identifies existing and potential environmental regulations that are expected to influence mining practices / coal demand and legislative initiatives to reduce greenhouse gas emissions.
Administrative costs are estimated by OSMRE.	The agency is asking for comment on these costs in the rulemaking.

CHAPTER 5 | COAL MARKET WELFARE IMPACTS

5.1 INTRODUCTION

This chapter presents our assessment of the coal market welfare impacts associated with the Proposed Rule. These include changes in welfare (i.e., consumer and producer surplus) realized by coal producers and consumers, as well as costs borne by government.[112] The environmental improvements associated with the rule may also result in changes in social welfare (e.g., from improvements in water quality in streams). Such changes are addressed in Chapter 7.

Exhibit 5-1 summarizes our estimates of the Proposed Rule's market welfare impacts. As indicated in the exhibit, we estimate annualized market welfare losses of $34 million through the year 2040, based on a seven percent discount rate. In the sections that follow, we document these results in greater detail and describe the methods that we employed to generate these results.

EXHIBIT 5-1. ANNUALIZED COAL MARKET WELFARE LOSSES OVER THE PERIOD 2020 THROUGH 2040 FOR THE PROPOSED RULE, DISCOUNTED AT 7 PERCENT (MILLIONS, 2014 DOLLARS)

Annualized Welfare Loss	$34.05
Welfare reductions in coal markets	$34.00
Welfare reductions related to government costs	$0.05

5.2 METHODOLOGY FOR WELFARE ESTIMATION

5.2.1 WELFARE EFFECTS ON COAL PRODUCERS AND CONSUMERS

Economists typically measure the adverse impacts of regulatory actions such as the Proposed Rule in terms of the resulting economic welfare losses.[113] Compliance cost estimates such as those in Chapter 4 provide an approximation of these effects, but they represent an accounting measure of impacts rather than an economic measure. The former reflects expenditures associated with compliance activities, whereas the latter reflects foregone benefits to both consumers and producers affected by regulatory change. These welfare losses are typically measured as changes in producer and consumer

[112] The discipline of welfare economics focuses on optimizing an allocation of resources by considering the overall effect on a population's well-being. The "welfare impacts" of a rule are accordingly a measure of the overall effect of the rule on well-being of society (i.e., social welfare) or within a given market (e.g., coal market welfare effects).

[113] Just, R.E., Hueth, D.L., and Schmitz, A. 2004. *The Welfare Economics of Public Policy.* Edward Elgar: Northampton, MA.

surplus. Producer surplus is the difference between the market price of a good and the marginal cost of production, and consumer surplus is the difference between what consumers are willing to pay for the good and the market price. Based on the supply and demand functions shown on the left-hand side of Exhibit 5-2, producer surplus is represented by area A and consumer surplus is represented by area B.

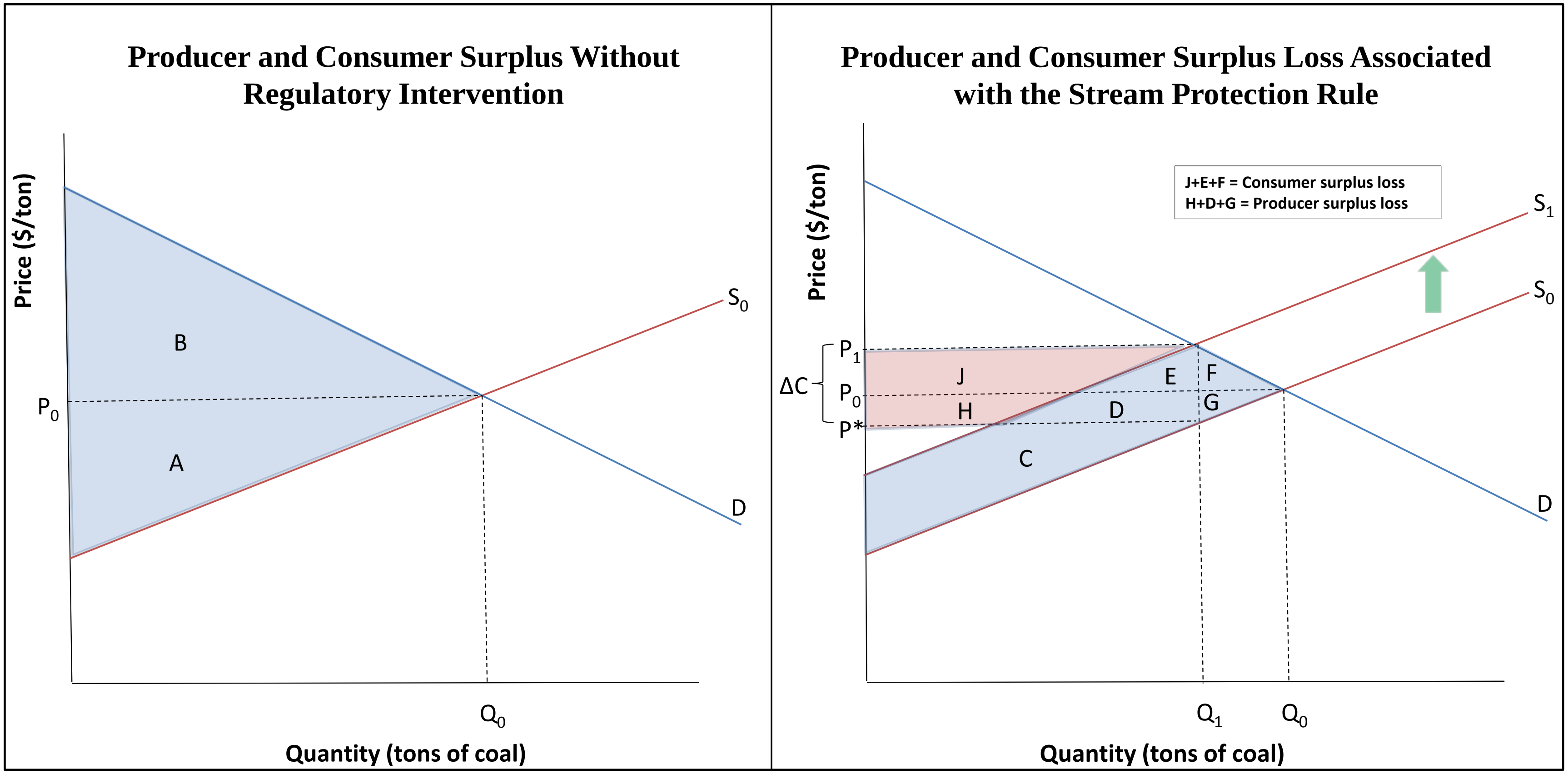
The Proposed Rule is expected to affect U.S. markets for coal by increasing the cost of production (i.e., shifting the supply function upward). As shown on the right-hand side of Exhibit 5-2, this shift results in an increase in coal prices from P_0 to P_1 and a reduction in coal production from Q_0 to Q_1. The sum of areas C through G in Exhibit 5-2 (the blue shaded area) represents the total welfare loss associated with these changes.

Ideally, we would estimate these welfare losses based on detailed information on the market supply and demand for coal. This would include information on supply and demand elasticities (i.e., how supply and demand respond to changes in price), and the extent to which the market supply function changes (i.e., shifts) as a result of the rule. This detailed information, however, is not readily available. The models developed and maintained by EVA, as described later in this chapter, do not explicitly model coal markets based on coal supply and demand functions. Instead, the EVA models estimate coal supply and demand based largely on the demand for electricity, (the production of which accounts for more than 90 percent of U.S. coal demand)[114], unit-by-unit information on the cost of producing electricity with coal versus the corresponding cost with natural gas, and detailed data on coal production costs by region. This bottom-up approach of deriving coal supply and demand employs a rich representation of coal supply and demand, but does not rely on an aggregate (top-down) specification of the market supply and demand functions for coal.

In the absence of detailed specifications of coal supply and demand functions, we employ a reduced-form approach for estimating the welfare losses associated with the Proposed Rule. Under the assumption that the market supply and demand functions are both linear, we may approximate the welfare losses of the rule based on the estimated change in coal production costs summarized in Chapter 4 and changes in coal production and consumption estimated by the EVA models.

[114] U.S. EIA. 2014b. Monthly Energy Review August 2014. U.S. Department of Energy, Office of Energy Statistics.

EXHIBIT 5-2. ILLUSTRATION OF PRODUCER AND CONSUMER SURPLUS



Note: The sum of areas A and B in the graph on the left represent producer and consumer surplus in the baseline. The sum of areas C, D, E, F, and G in the right-hand graph represents the total surplus losses associated with the Stream Protection Rule. Of this, Areas F and G represent deadweight loss (i.e., the surplus loss associated with reduced production and consumption), and the sum of Areas C, D, and E represents the surplus loss associated with the increased cost of producing Q_1 tons of coal. Under the assumption of linear supply and demand functions, the sum of Areas C, D, and E is equal to the sum of areas J, H, D, and E.

To estimate welfare loss represented by the area shaded blue in the right-hand side of Exhibit 5-2, it is useful to consider two separate portions of this area: (1) the area to the right of the new equilibrium quantity, Q_1 (F+G), and (2) the area to the left of this quantity (C+D+E). The former represents the deadweight loss associated with the rule (i.e., the welfare loss associated with the reduced quantity of coal produced and consumed), while the latter represents the welfare loss associated with the increased cost of coal production and transport. We further split the deadweight loss associated with the rule into losses to consumers, as represented by area F, and losses to producers, as represented by area G. Under the assumption that the demand and supply functions are linear, we estimate the deadweight loss represented by triangles F and G combined as follows:

(1) $DWL = ½(\Delta Q)(\Delta C)$

Where DWL = total deadweight loss, including losses to both consumers and producers (area F + G in Exhibit 5-2),

ΔQ = the change in the quantity of coal produced and consumed (Q_1-Q_0), as derived from the EVA suite of models.

ΔC = change in per-ton coal production and transportation costs as a result of the rule at a given quantity produced.[115]

The approach represented by Equation 2 assumes that the difference between the new supply function and the pre-rule supply function is constant and equal to the per ton production and transportation cost increase associated with the rule.[116] In addition, the approach in Equation 2 estimates the deadweight loss in aggregate. Dividing this loss between consumers (represented by area F in Exhibit 5-2) and producers (represented by area G) would require estimates of the weighted average price of coal in the baseline and with the Proposed Rule (P_0 and P_1 in Exhibit 5-2, respectively).

As noted above, the sum of areas C, D, and E represents the welfare loss associated with the increased cost of coal production and transport. Under the assumption of linear supply and demand functions, this is equivalent to the sum of areas H, J, D, and E.[117] We estimate this area by applying the increased cost of coal production and transportation on a per ton basis to the quantity of coal produced following promulgation of the rule (Q_1), as summarized by Equation 2.

(2) $WL_C = Q_1(\Delta C)$

Where WL_C = welfare loss associated with increased coal production costs (sum of areas H, J, D, and E in Exhibit 5-2),

Q_1= equilibrium quantity of coal produced following promulgation of the rule, and

[115] Note that this does not include government costs associated with the rule.

[116] Due to differences in the rule's cost impact across regions and mine types, the difference between the new supply function and the pre-rule supply function may not be constant. At the margin, we would expect that this difference may be greater than the average distance between the two functions, as represented by ΔC.

[117] Linearity of supply and demand also implies that area C equals the red shaded area H plus J.

ΔC = change in per-ton coal production and transportation costs as a result of the rule at a given quantity produced.

Similar to Equation 1, the approach represented by Equation 2 assumes that the difference between the Proposed Rule and baseline supply functions is constant and equal to the per ton cost increase associated with the rule. Under this assumption, the blue shaded area to the left of Q_1 in Exhibit 5-2 may be estimated by multiplying Q_1 by the per ton increase in coal production and delivery costs. We estimate the change in coal production costs based on the cost data presented in Chapter 4. The change in coal transportation costs is derived in the EVA suite of energy market models. To the extent that the distribution of coal production across regions shifts as a result of the Proposed Rule, the average distance over which coal is transported may also change. EVA's suite of models estimates the transportation cost impact associated with such changes.

Combining the estimates derived from Equations 1 and 2 yields the estimated economic welfare loss associated with the Proposed Rule. We estimate this loss for the U.S. in aggregate, treating coal as a national product market. Although the EVA models assess coal market impacts at the regional level (see discussion below), we estimate the welfare losses of the rule in aggregate for the U.S. as a whole to capture interactions among coal markets in different regions. For example, the cost of producing coal may increase in a specific region under the rule, which would typically suggest a decline in production as depicted in the right-hand side of Exhibit 5-2. Because the rule leads to more significant cost increases in other regions, however, production in the region in question is projected to increase under the rule rather than decrease (due to shifts in production from more costly regions). The most straightforward approach for estimating welfare impacts in the context of such production transfers is to aggregate regional sub-markets into a single national market. Under this national approach, many of the regional changes in production offset each other, leaving the analysis to focus on the net change in production associated with the rule.[118]

To develop a national representation of the U.S. coal market, we sum the production data generated by the EVA models. In addition, we estimate the weighted average change in coal production costs as a production-weighted average of the per ton cost increases implied by the model mines analysis presented in Chapter 4.

We emphasize that the methodology presented in this section provides an approximation of market welfare effects based on the readily available data. To the extent that any of our assumptions prove to be incorrect, the actual market welfare impacts of the rule could differ from the results derived from our methodology. For example, if the supply and demand functions for coal are not linear, the market welfare impacts of the rule could be greater or less than we estimate.

5.2.2 GOVERNMENT COSTS

Costs incurred by government also represent a market welfare loss associated with the Proposed Rule, as the costs incurred by government to administer the rule represent a diversion of finite resources from other uses. Chapter 4 presents our approach for

[118] Information on the regional compliance cost impacts of the rule is presented in Chapter 4.

estimating the costs realized by government as a result of the rule. We incorporate the government costs presented in Chapter 4 into the assessment of market welfare impacts presented in this chapter.

5.2.3 VALUATION OF STRANDED RESERVES

Another measure of the Proposed Rule's welfare effects under some regulatory alternatives would include the reduction in coal reserve values associated with the rule. That is, under some alternatives, some coal reserves may be "stranded" or "sterilized" (see Chapter 3).We define stranded reserves as those that are technically and economically minable, but unavailable for production given the new requirements and restrictions included in the Proposed Rule. From a welfare economics perspective, this represents a welfare cost associated with the Proposed Rule.

Our analysis indicates that there will be no increase in stranded reserves under any of the Alternatives.[119] That is, the engineering analyses underlying the economic analysis determined that the same volume of coal could be mined under each of the Alternatives as under the baseline alternative.[120] However, to provide a framework for the analysis of the economic impact of stranding coal reserves, in this section we describe the steps that would be followed to assess the economic impact of stranding.

In the hypothetical case, for reserves that mines would be unable to extract from the ground due to a proposed rule, the loss in reserve value would be the baseline value of these reserves, as represented by the present value of the *economic* profits that mines (or the land owner) would earn on these reserves over time, where economic profit is specified as the value of the coal, as extracted, minus the cost of extraction, including normal profits (i.e., opportunity costs of capital).[121] Normal profit may be estimated based on the weighted average cost of capital to the coal mining industry. That is, the cost associated with stranding coal in the ground would be measured as the value of that coal in the ground to the mine operator or landowner.

Note that estimates of foregone reserve value would vary across different baseline scenarios analyzed, as baseline policies that encourage substitution to other fuels would reduce coal prices and slow the production rate for these reserves, both of which would reduce reserve value. An analysis of the change in reserve value for foregone reserves would rely on baseline market forecasts for coal (described below) for information on coal prices and production under each baseline scenario. Estimation of these reserve values would also reflect the cost of extracting these reserves (to assess profitability).

Equation 3 summarizes how the welfare loss associated with the stranding of reserves may be estimated:

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[119] Under Alternative 2, it is possible that there would be some stranding of reserves in Central Appalachia if disposal capacity is unavailable for excess spoils. Because we identified no information suggesting that disposal capacity would be unavailable, the analysis in Chapter 8 assumes no stranding of reserves for Alternative 2.

[120] Even if there is no stranding of reserves, coal production may decline as shown in the results below. A decline in production does not necessarily imply that reserves are stranded. Instead, it may simply reflect reduced cost competitiveness for coal relative to other energy sources, which may slow the annual rate of production.

[121] Normal profit represents the return necessary to keep capital deployed in its current use in the long run.

$$(3)\ \Delta R_u = \sum_{t=1}^{N} \frac{Q_{u,y}\left(P_{0,y} - (1+\pi)C_{0,y}\right)}{(1+r)^t}$$

where ΔR_u= change in value for unrecoverable reserves,

$Q_{u,y}$ = the quantity of coal from unrecoverable reserves that is sold under the baseline in year *y*,

$P_{0,y}$ = the per-ton price of coal under the baseline in year y,

$C_{0,y}$ = the per-ton cost of coal production under the baseline in year *y*,

$\boldsymbol{\pi}$ = normal profit margin per ton of coal produced (based on the weighted average cost of capital)

r = discount rate, and

t = time.

Implementation of the approach represented by Equation 4 requires detailed information on trends in coal prices over time, the likely timing of production for a given coal reserve, and the costs of production for a given reserve. Each of these variables introduces uncertainty into the assessment of reserve value. Therefore, as an alternative to the approach outlined in Equation 4, if stranded reserves were expected, we would estimate the welfare loss associated with the stranding of reserves based on available data on the current value of coal reserves on a per ton basis. Based on reserve transaction data, we would assume that the value of stranded reserves is $1.50 to $2.50 per ton for Appalachian steam coals, $6.00 to $8.00 per ton for metallurgical coals, and $0.75 to $1.25 per ton for Powder River Basin coal.[122,123] These are the prices paid for reserves and therefore approximate their value to society.

5.3 MODELING MARKET DYNAMICS

Implementation of the approach outlined above for the estimation of market welfare impacts requires information on the changes in coal production and coal prices likely to result from the rule. In this section, we describe the suite of energy market models that we used to estimate these coal market impacts.

5.3.1 OVERVIEW

The regulatory options under consideration by OSMRE will affect coal production and consumption patterns across the U.S. With respect to production, the operational restrictions engendered by the various regulatory options will increase the cost of producing coal, which may lead to an aggregate reduction in coal production across the U.S. Such changes in coal production, however, will not be uniform across the entire U.S., as the Proposed Rule will differentially affect mine production costs by region and

[122] Estimates obtained from Alpha Natural Resources, Inc., Form S-4 Registration Statement, Amendment No. 1 files with the U.S. Securities and Exchange Commission for the proposed merger of Alpha with Massey Energy, April 12, 2011.

[123] These values represent the present value of future profits that coal producers might earn from these reserves.

mine type. For example, as indicated in Chapter 4, production costs for surface mines are expected to increase more than costs for underground mines under the Proposed Rule. At the margin, this change in relative costs will affect the competitiveness of surface mines relative to underground mines. Similarly, the changes in coal production costs associated with the rule vary by region due to differences in geology, baseline mining practices, and other factors. This will lead to changes in the distribution of production across mining regions. The increase in coal prices associated with higher production costs may also lead to a reduction in coal consumption. As prices rise, power plants, industrial facilities, and other coal consumers may substitute other sources of energy (e.g., natural gas) for coal.[124] The changes in coal consumption associated with the rule will vary by region due to regional differences in the price of coal and the price of substitutes.

To assess these and related energy market impacts in the context of the rule, we employ a suite of energy market models designed and maintained by EVA. These models include significant detail with respect to both coal production and consumption. The EVA models simulate coal production by mine type and mine region, accounting for regional differences in reserve depletion, coal mining technology, permit restrictions (e.g., the impact of valley fill permit limits on Appalachian surface mining), mine safety regulations, labor availability and costs, and the availability and cost of Federal coal leases. Similarly, the models' treatment of coal demand considers a range of factors that influence demand, including (1) changes in electricity demand and the associated implications for power plants' demand for coal, (2) fuel substitution associated with changes in the price of coal relative to natural gas, and (3) environmental regulations that affect power plant demand for coal. The coal demand sectors incorporated into the EVA models include:

- Electric power
- Domestic metallurgical coal consumers (coke ovens and pulverized coal injection)
- Industrial consumers (industrial boilers, cement kilns, etc.)
- Commercial consumers (universities, public buildings, etc.)
- Export metallurgical consumers
- Export steam coal consumers

Employing the EVA models and results, we estimate the rule's impact on coal production by region and mine type, coal demand by major consuming sector, and coal prices by region.

5.3.2 COAL PRODUCTION, CONSUMPTION, AND PRICE CHANGES

We apply EVA's suite of market forecasting models to estimate the coal production, consumption, and price impacts of the Proposed Rule relative to baseline conditions. Below we expand upon the characterization of the baseline presented in Chapter 3,

[124] Similarly, increased prices for metallurgical coal will reduce demand for it, through induced productivity increases at integrated steel mills, substitution to steel from mini-mills, or substitution to steel imports.

summarize the EVA models employed in this analysis, and describe how we use these models to assess the market impacts of the rule.

5.3.2.1 Baseline Specification

We assess the energy market impacts of the Proposed Rule relative to a baseline scenario that reflects the set of assumptions we consider most likely to occur. We also specify two other baseline scenarios that differ with respect to the future trajectory of coal demand and supply. The low and high demand baselines include alternative assumptions for a limited number of variables that have a significant influence on coal demand. Thus, the low- and high-end alternatives developed for this analysis represent feasible, but less likely, baseline scenarios. We present the compliance cost impacts of the Proposed Rule incremental to these alternative baselines in Chapter 4. This approach is consistent with OMB Circular A-4, which states that the primary baseline should reflect the “best assessment of the way the world would look absent the proposed action.” Circular A-4 also states that when “more than one baseline is reasonable and the choice of baseline will significantly affect estimated benefits and costs” it is appropriate to measure “benefits and costs against alternative baselines.”

Exhibit 5-3 provides a description and an explanation of the assumptions for the alternative baselines. Additional detail on the variables that affect the specification of the baseline scenarios are as follows:

- Electricity demand: Because domestic power plants account for approximately 90 percent of the coal consumed in the U.S.,[125] an accurate forecast of coal-fired electricity generation is critical to specification of baseline coal demand. Our baseline forecast of coal-fired electricity generation is a function of electricity demand growth, the coal-fired generating capacity available to meet demand, environmental regulations that affect the dispatch of coal-fired power plants, natural gas prices, and generation from nuclear and renewables.
- The electricity demand growth forecast is derived from expectations for economic growth combined with the outlook for each sector. The forecast assumes continued but slower growth in demand in the residential and commercial sectors as a result of new lighting standards and improvements to energy efficiency in consumer electronics. After a modest rebound in industrial electricity demand, the forecast assumes declining industrial demand after 2015 due to continued losses in manufacturing capacity.

[125] U.S. EIA. 2014b. Monthly Energy Review August 2014. U.S. Department of Energy, Office of Energy Statistics.

EXHIBIT 5-3. ALTERNATIVE COAL DEMAND SCENARIO ASSUMPTIONS

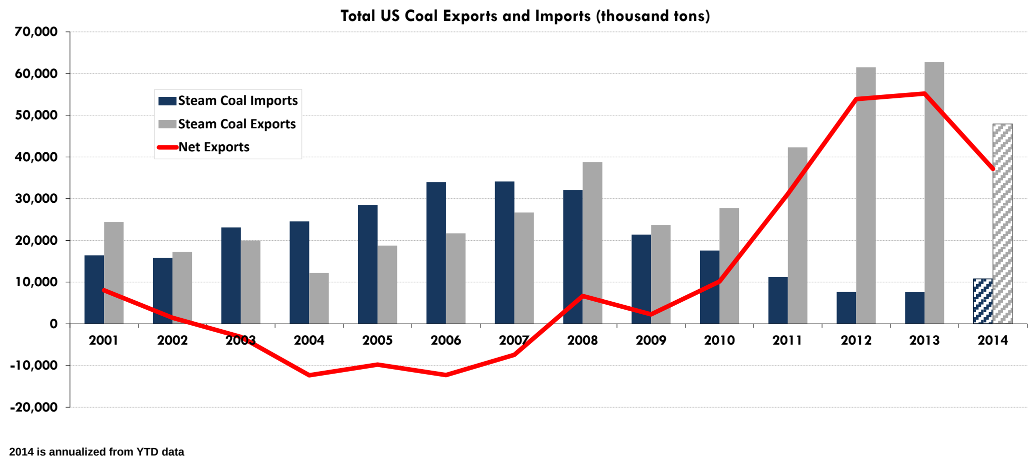
METRIC	LOW COAL DEMAND	HIGH COAL DEMAND
Description	Clean Power Plan proposed by EPA in June 2014 assuming individual state compliance using mass-based limits.	High natural gas prices combined with higher coal exports
Explanation	The Clean Power Plan results in a significant reduction in utility demand by 2020 according to both EPA and EVA analyses.	Utility coal demand is capped by installed coal capacity. With a significant amount of coal capacity being retired and no new coal capacity forecast, the upside potential demand is limited. With higher gas prices, highest coal demand was realized.

U.S. Coal Exports:

The export market has shown substantial growth in recent years driven by strong global demand. The U.S. is one of the three traditional sources of supply of metallurgical coals and has benefitted from the strong global demand for this product, particularly in the Pacific market. Australia is by far the largest source of metallurgical coal exports, typically accounting for about 60 percent of the market. The U.S. and Canada are a distant second and third. Europe continues to be the largest market for metallurgical coals. The relatively strong export market for U.S. metallurgical coals during the 2010 through 2013 period was due also to growth in exports to the Asian market.

The recent growth in U.S. coal has restored the U.S. to export levels not experienced since the early 1990s (Exhibit 5-4A).

EXHIBIT 5-4A. TOTAL U.S. COAL EXPORTS AND IMPORTS (THOUSAND TONS)



U.S. coal exports include metallurgical ("met") coal and steam coal. The met coal, which is primarily used to produce metallurgical coke for steel-making, consists of a variety of grades typically differentiated by volatility and reflectance. Almost all met coal exports originate in the Appalachian region. Steam coal exports are of different types and origins, including low-sulfur and high-sulfur Appalachian coals, high-sulfur Illinois Basin coal, Rockies bituminous coals, and Powder River Basin sub-bituminous coal. Imports of coal to the U.S. are almost entirely steam coal delivered to power plants on the Gulf Coast and East Coast. Imported steam coals principally originate from South America (Colombia and Venezuela) and displace coal produced in Appalachia.

U.S. met coal exports have soared in response to the rise in world met coal market prices. From the historical low point of 22 million tons per year in 2002 and 2003, met coal exports exceeded 60 million tons in 2012 and 2013. This coal is shipped to world markets primarily out of the East Coast ports of Hampton Roads and Baltimore, the Gulf Coast ports of Mobile and New Orleans and the Great Lakes ports to Canada.

The traditional source of U.S. steam coal exports was bituminous coal from Appalachia (principally low-sulfur coal), which was best suited to the quality specifications of the world market. This coal was shipped out of the East Coast and Gulf Coast ports to world markets. When world market prices were low prior to 2008, U.S. steam coal exports fell to very low levels and steam coal imports were rising steadily. The change in world coal markets since 2007 caused a sharp drop in steam coal imports and an increase in steam coal exports.

World coal prices have increased dramatically since 2003 due to a number of factors. The most significant reasons have been:

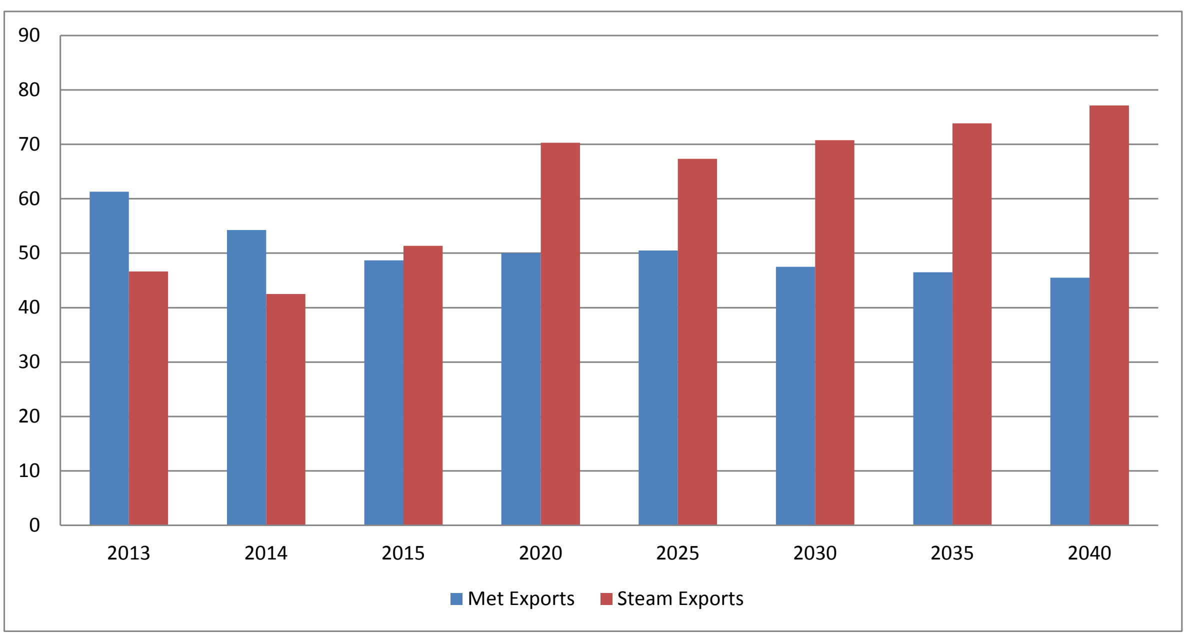
- A significant decline in the value of the US dollar, especially when compared with the currency of other coal exporting countries. As world coal trade is U.S. dollar-denominated and the U.S. is a relatively minor player, the lower value for the U.S. dollar causes world prices to rise as the other coal exporters seek to maintain net revenues. A weak dollar makes U.S. exports more competitive in world markets and imports to the U.S. more expensive. The dollar as measured against the Australian dollar (the world's largest coal exporter, especially of met coal) has been falling since 2002 (except for a brief period in the second half of 2009) and has had a major impact on world coal prices and US coal exports. Over 2013 and 2014, the U.S. dollar has regained some of its prior strength versus the Australian dollar which is one of the reasons that both global coal prices and U.S. exports are lower in 2014.

- Large coal demand growth in Asia, especially China and India. The increased demand for imports from world coal markets, both for met coal and steam coal has driven the growth of US coal exports.

While in the past, U.S. coal exports were generally limited to Appalachian coal, the increase in world prices and demand have made coals from the Illinois Basin and Powder River Basin attractive to export to the steam market. These coals had previously not participated due to quality limitations of sulfur (Illinois Basin) and heat content (Powder River Basin). However, the increase in price of other coals has made the coals low-cost on a quality-adjusted basis, so there is now an economic incentive to use these coals instead of the traditional low-sulfur bituminous coals.

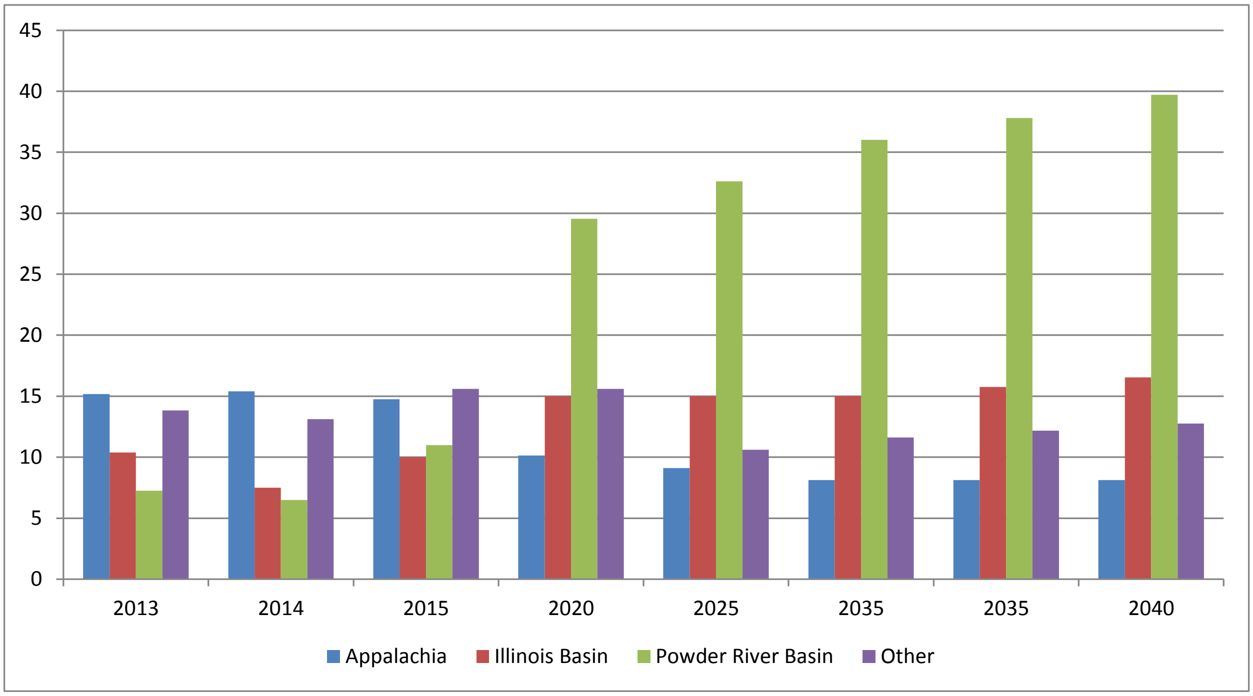
The base forecast assumes U.S. coal exports remain strong through the forecast period. As shown in Exhibit 5-4B, exports are expected to stay above 100 million tons per year throughout. However, the mix of exports is expected to change from primarily metallurgical to primarily steam. The shift reflects the limited remaining U.S. metallurgical coal supply combined with increased production from both Australia and Canada and non-traditional sources such as Mozambique and Mongolia.

EXHIBIT 5-4B. FORECAST OF U.S. COAL EXPORTS (MILLION TONS)



In addition, the mix of steam coal exports is expected to change over the forecast period. As shown in Exhibit 5-4C, the largest growth in exports is expected to come from the Illinois Basin and the Powder River Basin. Exports from Appalachia are expected to decline from current levels due to their relatively high production costs and the market acceptance of the other coal types.

EXHIBIT 5-4C. U.S. STEAM COAL EXPORTS (MILLION TONS)



There is sufficient terminal capacity (existing or under firm development) on the east coast of the U.S. and the U.S. Gulf. In order to realize the export forecast for western U.S. coals, one or more domestic terminals must be constructed on the west coast. Currently western coals are primarily being exported through Canadian terminals in British Columbia, the St. Lawrence Seaway, and the U.S. Gulf.[126] In order to be competitive in the Pacific market in the long-term, exports of Powder River Basin coal cannot afford the extra freight these options entail.

The export assumptions incorporated into the primary baseline reflect a moderate increase in export terminal capacity and a somewhat stronger U.S. dollar. The high coal demand case reflects a continued weakness of the U.S. dollar and significant success in terminal expansions, whereas the low case reflects strengthening of the U.S. dollar and limited success in realizing terminal expansions.

[126] There are also some most exports through west coast U.S. terminals.

Other Domestic Markets: Although much smaller than the utility market, the domestic metallurgical and industrial/other coal markets are significant sources of U.S. coal demand. Domestic metallurgical coal demand is tied to coke oven capacity which is expected to decline over the forecast period as retirements of existing ovens exceed additions of new ones. The industrial/other market is expected to decline due to fuel switching and lost demand. The industrial/other and domestic metallurgical coal forecasts were fixed for the analysis.

Natural Gas Prices: Coal demand from the electric utility industry in both the short-run and long-run depends significantly on natural gas prices. Low natural gas prices may reduce coal demand in the short term through changes in power plant dispatch. When natural gas combined cycle units are cost competitive, they are dispatched ahead of coal-fired generation. This substitution of natural gas for coal is occurring with increased frequency as a result of low natural gas prices. Low natural gas prices also make new coal plants uneconomic in the long-term. Even assuming that advanced coal combustion technology is commercialized (*i.e.*, available for use at power plants), the market penetration of this technology may be limited because of the comparatively low cost of alternatives such as natural gas combined cycle. Conversely, high natural gas prices coupled with the commercialization of advanced coal combustion technology would create an opportunity for the development of a new generation of coal-fired plants.

The increased supply of natural gas from new shale plays has resulted in lower natural gas prices and significant displacement of coal-fired generation by natural-gas fired generation. The displacement has been greatest where coal generation is relatively high-cost, which is primarily generation from plants fired by low sulfur bituminous coals in markets remote from the coal supply sources.

The variables outlined above contribute to our specification of the primary, low-demand, and high-demand baseline scenarios, and generate uncertainty in the base case from which we model the impact of the Proposed Rule. Our assumptions for the primary baseline scenario are summarized in Exhibit 5-5. Compliance cost impacts associated with alternative baseline scenarios are presented in Chapter 4. Consistent with these results, the market welfare impacts would be expected to be greater than for the Proposed Rule under the high-demand baseline scenario, and lower under the low-demand baseline scenario. Appendix F contains information on the assumptions for alternative discount rate assumptions. The most significant drivers of coal demand in each alternative are electricity demand growth, natural gas prices, advanced coal combustion technology penetration and coal export assumptions.

EXHIBIT 5-5. PRIMARY BASELINE ASSUMPTIONS

	EXTERNAL ASSUMPTIONS FOR EVA's COAL FORECASTS					
	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	
Real GDP (Average Annual Growth)	2.7%	0.2%	1.8%	1.8%	1.9%	
Total Electricity Demand (Average Annual Growth)	0.4%	1.1%	0. 9%	0.9%	0.9%	
Residential Electricity Demand (Average Annual Growth)	-0.5%	0.5%	0.6%	1.0%	1.1%	
Commercial Electricity Demand (Average Annual Growth)	0.3%	0.9%	1.0%	1.1%	1.3%	
Industrial Electricity Demand (Average Annual Growth)	2.0%	2.1%	1.0%	0.49%	0.2%	
Government Regulations:						
Clean Air Interstate Rule (CAIR)	Yes					
Mercury and Air Toxics Standard (MATS)	Yes by end of 2015					
Cross States Air Pollution Rule (CSAPR)	Yes through MATS compliance					
Cooling Water Intakes Rule 316(b)	Comply by 2018					
Coal Combustion Residuals	Comply by 2018					
NAAQS Nox Revisions	Yes through MATS compliance					
Regional Haze	Announced settlements in West					
New Source Performance Standards for Greenhouse Gases	Not explicit but cost hurdle for new coal					
Regional CO2 Programs	RGGI and AB32					
	2013-2015	2016-2020	2021-2025	2026-2030	2031-2035	2036-2040
Coal Capacity Additions: Megawatts (MW)	1,529	-	-	-	-	-
Coal Capacity Retirements (MW)	21,865	27,104	4,477	7,971	20,212	33,887
Nuclear Capacity Additions (MW)	1,180	5,019	-	-	-	-
Combine-Cycle Natural Gas Capacity (MW)	15,964	47,638	8,573	40,061	96,203	105,932
	2015	2020	2025	2030	2035	2040
Natural Gas Prices (2014$ per MMBtu at Henry Hub)	$4.51	$5.28	$5.79	$6.30	$7.01	$7.93
Non-Utility Coal Demand (Million Tons)						
Domestic Metallurgical	21.4	20.6	20.5	20.3	20.2	20.1
Domestic Other	42.7	39.7	38.1	36.7	36.7	34.8
Export Metallurgical	48.7	50.0	50.5	47.5	46.5	45.5
Export Steam	51.2	70.1	67.2	70.6	73.7	77.0
Total	164.0	180.4	176.3	145.1	177.1	177.4

5.3.2.2 Description of Models Utilized for Analysis of Each Scenario

Using EVA's market assumptions discussed earlier that relate to electric power demand, environmental regulations, capacity retirements and additions, non-utility domestic coal consumption, exports, and coal pricing methodology, EVA developed a baseline demand forecast from which to compare each SPR alternative.

In order to analyze the impacts of each Action alternative on electric power demand and the coal industry, EVA employs multiple inter-related models, shown in Appendix F The key models affecting coal demand are shown in Exhibit 5-6, to formulate its analysis. The following sections provide a summary of each model utilized.

- *Electricity Demand Model*

  The electricity demand model forecasts monthly demand for the residential, commercial, industrial, and transportation sectors for each U.S. power market. To forecast long-term electricity demand, EVA performs regression techniques against EIA's 826-data, which consists of monthly electric utility sales and revenue, along with the following variables:

  - Number of Households: sourced from Moody's Analytics;[127]
  - Disposable Income and GDP: sourced from Moody's Analytics;[128]
  - Industrial Production Index: sourced from Moody's Analytics;[129]
  - Heating/Cooling Degree Days: sourced from the National Oceanic and Atmospheric Administration (NOAA);[130]
  - Energy Efficiency Measures: sourced from EPRI's Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the US (January 2009);
  - Delivered Fuel Prices: Historical delivered coal prices adjusted by market intelligence and future forecasts of coal and transportation costs;
  - Retail Power Prices: Historical retail and average wholesale on- and off-peak power prices by major electricity trading hub from EIA adjusted for changes in market prices and utility rate base;
  - Price Elasticity of Demand: Price elasticity factors by market developed by EIA;[131,132] and

[127] Moody's Analytics. 2011. U.S. Macro/Financial Forecast Database.

[128] *Ibid*.

[129] *Ibid*.

[130] NOAA (National Oceanic and Atmospheric Administration). 2009. National Weather Service Climate Prediction Center, Degree Day Statistics. http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/

[131] U.S. EIA. 2003. Annual Energy Outlook 2003: With Projections to 2025. U.S. Department of Energy, Office of Integrated Analysis and Forecasting.

  - Electric Car Penetration: EVA's independent forecast of electric car sales and related consumption.

- *Electric Dispatch Model*

  - EVA utilizes the AuroraXMP dispatch model containing EVA's market data to determine future long-term coal generation demand. The model analyzes the entire U.S. electric power market on an 8760 hourly basis, which intends to mirror real world power pool dispatch operations. EVA's inputs into Aurora include the following: Power Plant Capacity additions: EVA tracks new power plant announcements, unit retirements and major environmental control retrofit projects. This information is incorporated according to EVA judgment.

  - Projected Plant Retirements: In addition to announced retirements, EVA analyzes what and when additional units will be retired as a result of new and expected EPA rules.

  - Construction and Performance Costs: EVA uses its internal forecast of new capacity costs and performance for alternative electricity supply options. Renewable Portfolio Standards (RPS): State RPS requirements are incorporated into the model.

  - Fuel Costs: Delivered coal costs are developed for each coal-fired generator based upon forecasts of coal prices and transportation rates.

- *Coal Burn Model*

  EVA's coal burn model summarizes the quantity (tons) of coal that each coal-fired plant will consume by supply region. This is performed by analyzing each plant's forecast coal generation determined from the electric supply model, its respective heat rate and future coal purchase decisions. The sources of the major inputs to the Coal Burn Model are:

  - Forecast Coal Generation by Power Plant: Electric Dispatch Model. Coal Receipts: The model utilizes EIA-923 data to summarize the current quality and quantity of coal purchased for each power plant.

  - Coal Selections: EVA determined plant-specific fuel strategy by year for the forecast period.

  - Heat Rate: The model uses estimates of the net heat rate for each plant using EIA-923 data, except as deemed appropriate to modify.

[132] A negative value for the own-price elasticity of demand indicates that as the price of a good increases, demand for that good declines. In other words, there is a negative relationship between price and demand. Hence, the own-price elasticity of demand is expressed as a negative number.

- *Delivered Coal Price Model*

  EVA maintains an engineering-based cost model that organizes the cost components (labor, fuel, supplies, etc.) to produce coal along with profit margins for each coal supply region. The long-term coal price forecast assumes market equilibrium and therefore reflects full operating costs of the price setting mines in each region with a return of and on capital. The produced coal cost is commonly termed 'Mine Price'. Prices for other qualities within each region are derived from the price-setting mines.

  In order to calculate the delivered price of coal for each coal-fired plant, EVA estimates the transportation cost to ship coal from the mine to each utility using a combination of known transportation costs, typical rail and barge rate metrics (cents per ton-mile), and other relevant information. The combination of the mine price and the transportation cost produce the delivered price of coal.

  The results from the coal burn model and the delivered coal price model are combined to calculate the average cost of coal for each coal-fired plant.

- *Coal Flows Model*

  EVA's Coal Flows Model combines the forecasts of utility coal demand (by supply region) with EVA's independent analysis of export, industrial/commercial, and domestic metallurgical coal demand to estimate coal flows by region. The results of the coal flows model are evaluated in the context of regional production capacity. If the demand forecast exceeds the regional forecast production capacity, adjustments are made to the Coal Price Model and/or the independent non-utility coal demand assessments to balance the market. As a result, the Coal Flows may be run multiple times until the markets are balanced.

5.3.2.3 Applying the EVA Models to Estimate Coal Market Impacts

Using the suite of models outlined above and the estimated compliance costs, we estimate the coal demand, supply, and price impacts of the Proposed Rule incremental to the baseline.

We evaluate the energy market impacts of Alternatives 2 through 9 incremental to the baseline. Alternative 1 retains current regulations and therefore has no associated impact. The baseline for this analysis includes the rulemakings outlined in Exhibit 5-5 as well as implementation of the EPA Clean Water Act Guidance issued in July 2011.[133] Our assessment of the Proposed Rule's energy market impacts is based on the direct cost impacts associated with complying with the new requirements of the Proposed Rule, described in Chapter 4.

[133] U.S. EPA. 2011a. Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the Environmental Justice Executive Order. Memorandum. July 11.

We employed the suite of models described above to assess the energy market impacts of the rule. Exhibit 5-6 illustrates our approach for using these models, the specific steps of which are as follows:

(1) Incorporate the Proposed Rule-adjusted coal price forecasts into the Delivered Coal Price Model. The result will be a delivered coal price forecast for each U.S. coal-fired power plant that reflects the variation in coal prices across each power plant's sources of coal.

(2) Incorporate the delivered coal price forecast into both the Electricity Demand Model and AuroraXMP Dispatch model.

(3) Run the Electricity Demand Model with the new delivered coal prices to reforecast electricity demand.

(4) Run the AuroraXMP model with the output from the Electricity Demand Model and the new delivered coal costs to reforecast electricity generation by type (i.e., nuclear, wind, coal, natural gas, etc.).

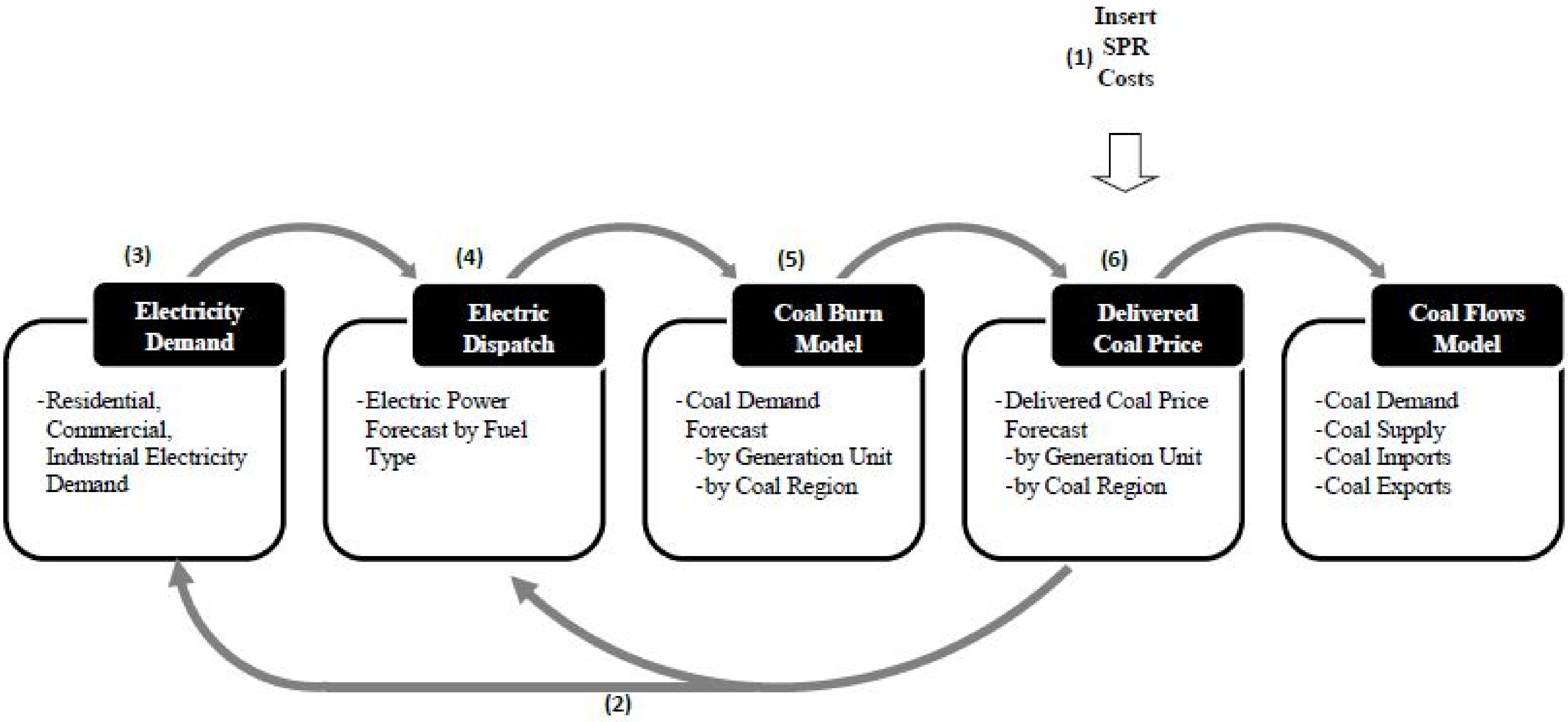
(5) To forecast power plant coal demand by coal type, run the Coal Burn Model with the new coal-fired generation forecast after making any necessary adjustments to the coal allocations.

(6) Run the Delivered Coal Price Model with the revised coal burn forecast to estimate the average delivered coal price given the coal mix estimated by the Coal Burn Model.

(7) Determine the impact of the Proposed Rule on demand for and price of U.S. coal by comparing the model results to the baseline forecast.

We follow these steps to estimate the energy market impacts of the Proposed Rule incremental to each of the three baseline scenarios outlined above.

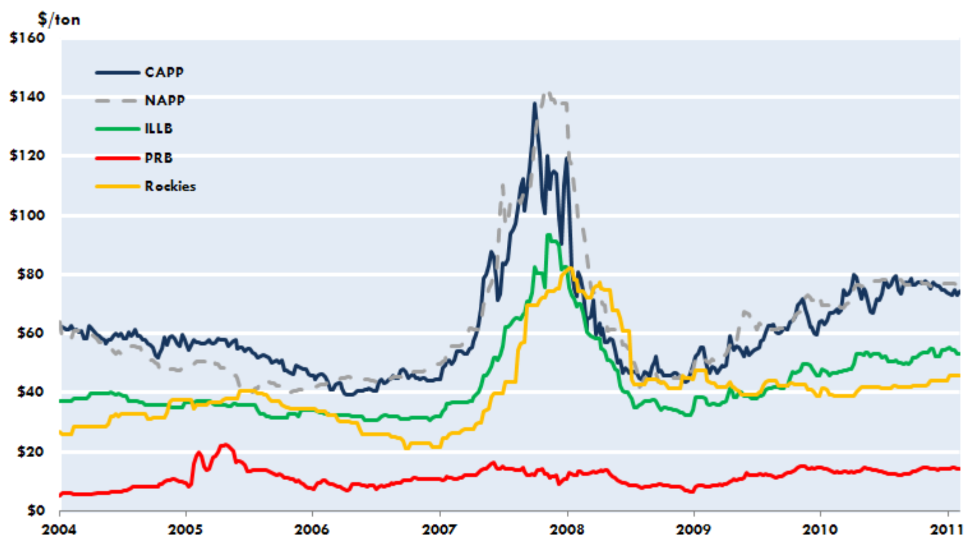
EXHIBIT 5-6. FLOW CHART OF EVA MODELS USED TO ANALYZE PROPOSED RULE IMPACT TO GLOBAL COAL MARKETS



As indicated above and illustrated in Exhibit 5-6, applying the EVA suite of models requires estimation of the immediate coal price impacts of the Proposed Rule. The per ton compliance cost values presented in Chapter 4 were translated into exogenous changes in prices to be introduced into the EVA models based upon the significance of the production associated with each of these values. Under the Proposed Rule, the most significant cost impact was on "large" Central Appalachia surface mines. Of the 123 million tons of Central Appalachian production in 2013, 51.8 million tons were from surface mines and 20.3 million tons were from surface mines that produced 1.0 million tons or more in 2013. In 2013, large surface mines accounted for 39 percent of surface mine production or 16 percent of total production for Appalachia. Given this relatively large share of production and the relatively large cost impact of the Proposed Rule on large surface mines in Central Appalachia, EVA (1) estimated the change in the Central Appalachian coal price as the per ton compliance costs and change in royalties for large surface mines in this region and (2) concluded that the change in the Central Appalachian price would likely be the main driver of prices in other regions.

To analyze the price impact of Proposed Rule compliance costs, we considered the interrelationship of prices between the major U.S. coal supply regions. Historically, coal prices have moved in a similar direction as changes in market factors occur, but not always by the same magnitude (Exhibit 5-7).

EXHIBIT 5-7. HISTORICAL PROMPT COAL PRICES ($/TON)



5.3.3 PROJECTED ENERGY MARKET IMPACTS

Following the approach outlined above, we assessed the coal production and price impacts of the Proposed Rule over the 2020 to 2040 period.[134, 135] As shown in Exhibit 5-8, we forecast a reduction in overall coal production over this period (compared to the baseline condition) ranging from approximately 0.2 to 4.6 million tons per year. This reduction largely reflects power plant substitution of natural gas for coal due to increased coal prices (see below). The increase in coal prices is driven by compliance costs incurred by mines as a result of the Proposed Rule. However, the price of coal increase over the baseline price will not by exactly the same as the increase in the cost of compliance as markets adjust over time. We expect coal production to decrease in aggregate under the rule, as illustrated in Exhibit 5-8.

We note that the changes in coal production summarized in Exhibits 5-8 and 5-9 and throughout this chapter do not reflect the costs of the Proposed Rule for the Alaskan coal industry. Excluding Alaska from the estimated changes in coal production presented in this chapter, however, is unlikely to significantly bias our results because Alaskan coal production represents just 0.2 percent of total U.S. coal production.[136] Thus, its exclusion from the EVA modeling analysis would not affect model results.

Complementing the results presented in Exhibit 5-8, Exhibit 5-9 presents the estimated percent change in aggregate, surface, and underground coal production under the Proposed Rule. The data in the exhibit suggest that the estimated changes in coal production likely to occur as a result of the rule are relatively modest—less than 0.5 percent for all years—compared to baseline coal production.

[134] This section provides summary-level information on the energy market impacts of the Proposed Rule relevant to the social welfare analysis. Chapter 4 presents an overview of production effects of the Proposed Rule and more detailed results—by year, region, and mine type—are available in Appendix F.

[135] The compliance cost figures were changed after the EVA analysis was conducted. EVA's opinion was that the change in compliance costs would not substantively affect their results and so the EVA analysis was not changed. The current EVA analysis is conservative in that it may slightly overstate the impacts on coal production given the final compliance figures.

[136] U.S. EIA. 2011f. Annual Coal Report 2010. U.S. Department of Energy.

EXHIBIT 5-8. ANNUAL CHANGES IN TOTAL U.S. COAL PRODUCTION UNDER THE PROPOSED RULE

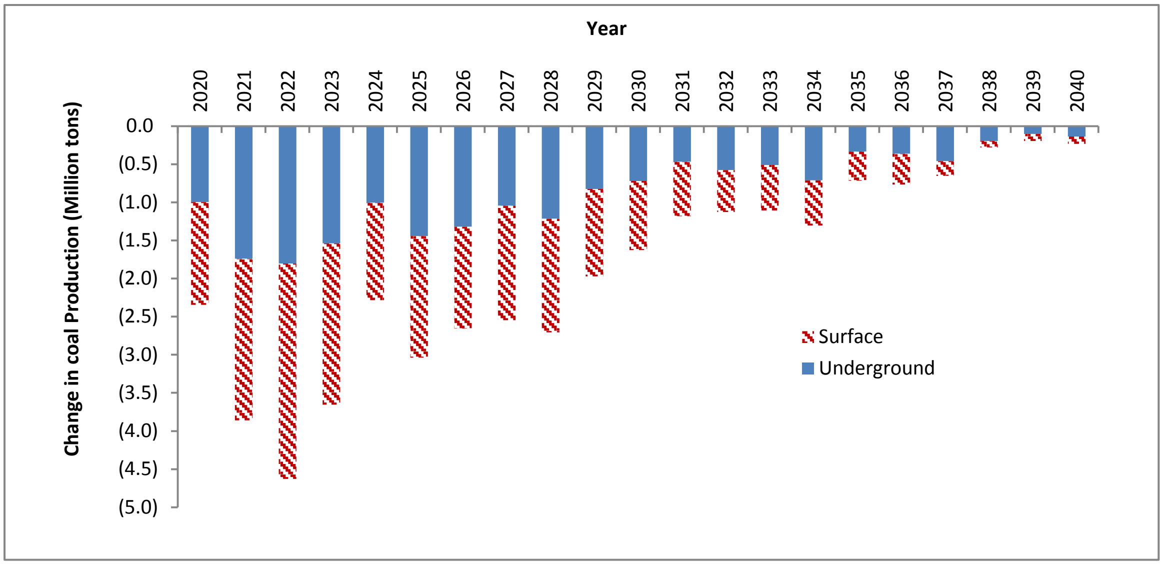
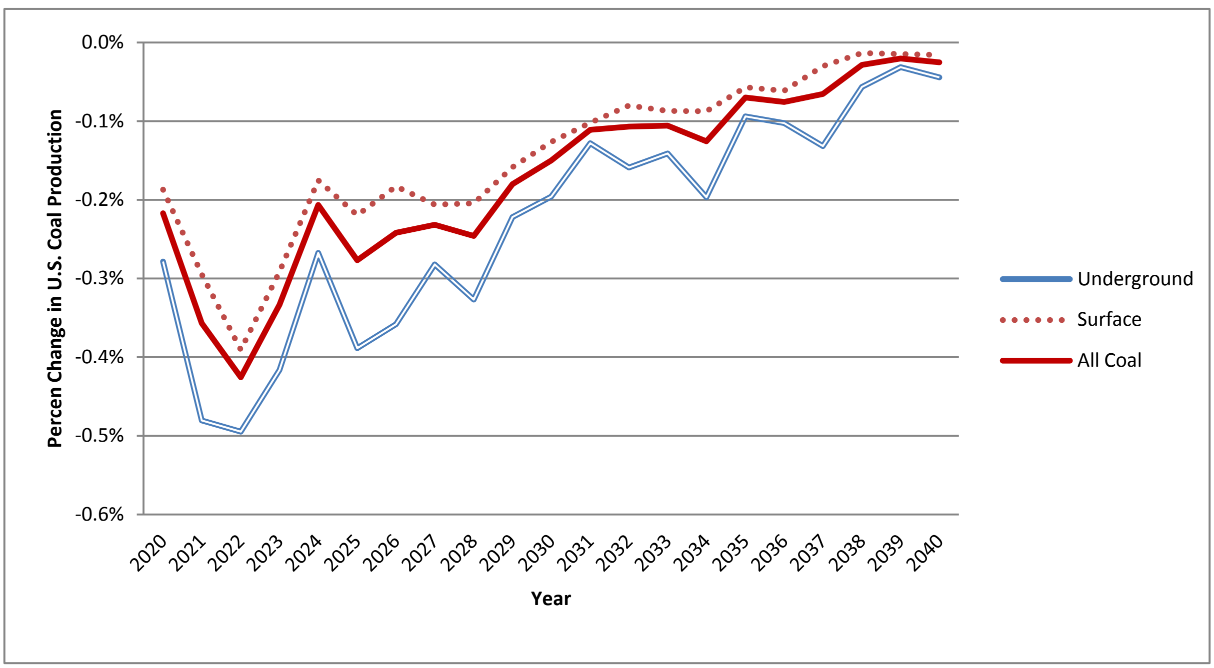


EXHIBIT 5-9. ANNUAL PERCENT CHANGE IN TOTAL U.S. COAL PRODUCTION UNDER THE PROPOSED RULE RELATIVE TO THE BASELINE FORECAST

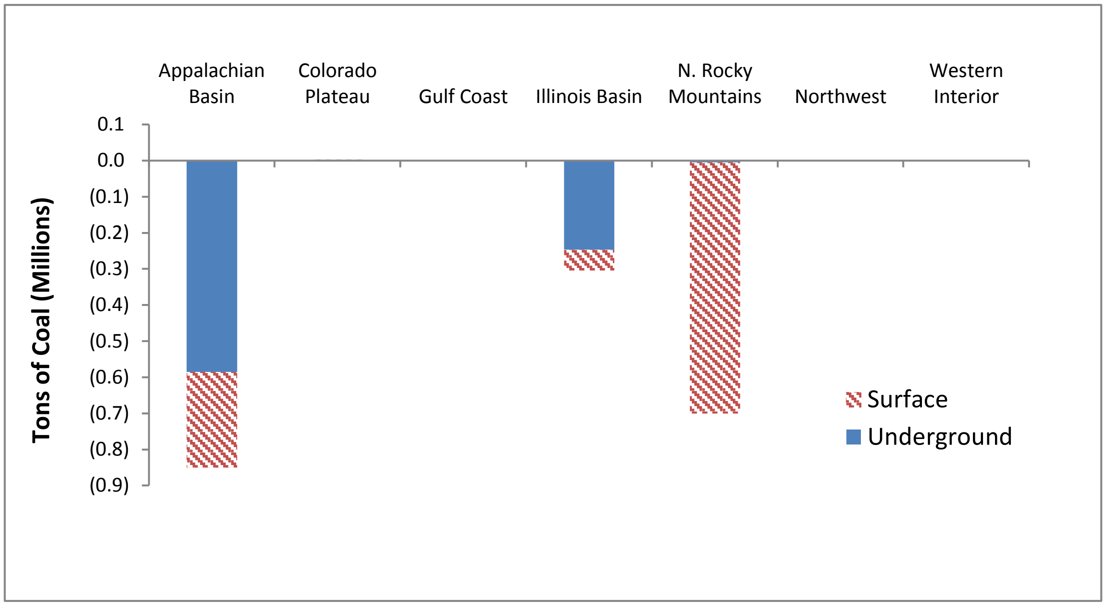


Exhibits 5-10 and 5-11 summarize the nationwide production changes illustrated in Exhibits 5-8 and 5-9. These results show that the Proposed Rule-induced reduction in coal production is heavily concentrated in the Appalachian Basin. This reflects the relatively high costs of the rule for this region relative to other regions. As indicated in Chapter 4, the cost impact of the rule on a per ton basis is greater in the Appalachian Basin, particularly in Central Appalachia, than in other regions. This reduces the competitiveness of Appalachian coal relative to coal from other regions and relative to substitute fuels (e.g., natural gas).

Exhibits 5-10 and 5-11 also show that the declines in coal production expected under the Proposed Rule occur primarily in the three major coal producing regions: Appalachian Basin, Illinois Basin, and Northern Rocky Mountains.

The decline in production in the Appalachian Basin reflects both its high increased production costs of the rule per ton relative to other regions and its relatively high level of coal production. The decline in the Northern Rocky Mountains and Great Plains Region surface production reflects the fact that this area is the largest coal producing region in the U.S. Although the increased costs per ton expected to be caused by the Proposed Rule are low for Northern Rocky Mountains and Great Plains Region surface mines relative to other regions, a small percent decline in surface production in this area translates to a larger change in total production than for any other mine type. The decline in production in the Illinois Basin reflects both its high increased costs of the rule per ton relative to other regions and its relatively high level of coal production.

EXHIBIT 5-10. AVERAGE ANNUAL COAL PRODUCTION CHANGE FORECAST BY REGION AND MINE TYPE FROM 2020-2040 UNDER THE PROPOSED RULE, 2020-2040 (MILLIONS OF TONS)



Notes:
The projected change in each region represents less than 0.5 percent of baseline study period regional production. The projected change in Appalachia represents 0.4 percent of baseline study period regional production (annual average of 236 million tons). The projected change in Illinois Basin represents 0.2 percent of baseline study period regional production (annual average of 170 million tons). The projected change in the Northern Rocky Mountains and Great Plains represents 0.1 percent of baseline study period regional production (annual average of 533 million tons).
For context, total coal production in 2012 was 1,106 million tons (MSHA, 2012).

EXHIBIT 5-11. AVERAGE ANNUAL U.S. PRODUCTION OVER THE 2020-2040 PERIOD

REGION	BASELINE (MILLION TONS)	PROPOSED RULE (MILLION TONS)	CHANGE (MILLION TONS)	CHANGE (PERCENT)
Appalachian Basin	236	235	(0.9)	-0.36%
Colorado Plateau	56	56	0	0%
Gulf Coast	54	54	0	0%
Illinois Basin	171	170	(0.3)	-0.18%
North Rocky Mountains/ Great Plains	533	532	(0.7)	-0.13%
Northwest	2	2	0	0%
Western Interior	1	1	0	0%
TOTAL	**1,053**	**1,051**	**(1.9)**	**-0.18%**

The results shown in Exhibit 5-10 show that, in absolute terms, the projected change in coal production associated with the Proposed Rule varies from year to year, though this change stays within a range of 0.2 to 4.6 million tons per year. This variability is common in large-scale models similar to the suite of EVA models employed in this analysis and may reflect the factors described below. The overall trend in these values, and the net changes over time, are likely to be more accurate than any given year's results.

- ***Changes in the electricity generation mix over time:*** The changes in coal production in EVA's models are partially dependent on the fuel mix used for electricity production in the baseline. If the power sector relies more on natural gas-based electricity production in a given year, this reduces coal demand and, by extension, reduces the coal production impact of the rule. In contrast, if coal accounts for greater than normal share of the fuel mix one year, the decline in coal use due to the Proposed Rule may be more significant.
- ***Retirement of coal-fired power plants and construction of gas-fired plants***: The variability in the Proposed Rule's coal production impacts over time may also reflect changes in the retirement of coal-fired power plants over time as well as changes in the construction of new gas-fired units. Power plant retirement and construction may vary significantly from one year to the next, causing sudden changes in the demand for coal.

The coal price impacts of the Proposed Rule will likely vary by coal type and region. With respect to coal type, these impacts may depend on several characteristics of a given coal, including its thermal value (measured as Btu per pound), its sulfur content, and its ash content. EVA's suite of models captures these differences by estimating coal prices for a series of reference coals for each region and subsequently estimates prices for other coals based on differences between these coals and the corresponding reference coal. Exhibit 5-12 presents the estimated coal price for these reference coals under the baseline and under the Proposed Rule. The results in the exhibit suggest that the change in coal prices under the rule may vary from 0.2 to 1.2 percent across regions. As noted above, the *long-run* price impact of the rule may be less than this estimated range. In the short run, coal consumers may find it costly to switch to alternative sources of coal in response to higher prices. In the long run, however, switching may be more feasible, which would dampen the price increase that materializes in the short run. Because the price effects presented in Exhibit 5-13 represent short run effects rather than the long-run equilibrium price impacts of the rule, we did not use these price estimates in our assessment of the rule's market welfare effects.

EXHIBIT 5-12. INITIAL COAL PRICE IMPACTS OF THE PROPOSED RULE ($/TON)

REGION	2015 BASELINE	2015 PROPOSED RULE	2020 BASELINE	2020 PROPOSED RULE	2030 BASELINE	2030 PROPOSED RULE	2040 BASELINE	2040 PROPOSED RULE
NAPP	56.04	56.04	58.26	58.39	63.03	63.16	69.98	70.11
CAPP	64.00	64.00	67.34	68.20	70.43	71.28	74.27	75.12
ILLB	42.48	42.48	44.75	44.99	46.15	46.40	47.72	47.97
PRB	14.19	14.19	16.02	16.07	17.33	17.38	19.57	19.62
RCK	36.24	36.24	38.50	38.60	38.95	39.05	39.60	39.69

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin
PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains

5.4 WELFARE LOSSES RESULTS

Exhibit 5-13 presents the estimated market welfare loss of the Proposed Rule by year from 2020 through 2040. As indicated in the exhibit, our analysis suggests that the welfare losses of the rule will decline over time. This decline is largely the result of the national coal market declining even without the Proposed Rule. As coal production declines over time, the absolute dollar amount of producer and consumer surplus declines (Exhibit 5-2 areas A +B). The declining coal market is seen in comparing the difference between the 2020 coal production baseline level for surface and underground (721 + 358= 1,079) and the 2040 coal production baseline for surface and underground (611 + 306 = 917), a decline of 162 million tons over this period, even without the Proposed Rule. In contrast, the rule itself is attributable to less than a 2 million ton decline. The level of producer and consumer surplus would be reduced considerably, as $Q_{0(2020)}$ is reduced by 162 million tons to reach $Q_{0(2040)}$ (Exhibit 5-2) As shown graphically, the level of Q_1 largely dictates the size of the welfare loss, whereas Q_0 - Q_1 is miniscule (917 – 917.2 = 0.2 million tons in 2040). Thereby the area J + E + H + D, the bulk of market welfare loss, diminishes in size from 2020 to 2040. The results in Exhibit 5-14 also show that costs to government represent a small fraction (less than one percent) of total market welfare losses. Most of the welfare loss within the coal market itself (column A in Exhibit 5-13) reflects changes in coal production and transportation costs (the sum of areas C, D, and E in Exhibit 5-2) rather than the deadweight loss associated with the decline in production resulting from the rule (areas F and G in Exhibit 5-2).

EXHIBIT 5-13. PRESENT VALUE ANNUAL WELFARE EFFECTS OF THE PROPOSED RULE, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$31.0	$0.04	$31.0
2021	$24.7	$0.04	$24.7
2022	$13.2	$0.04	$13.2
2023	$18.5	$0.04	$18.5
2024	$28.2	$0.03	$28.3
2025	$20.7	$0.03	$20.7
2026	$21.1	$0.03	$21.1
2027	$18.7	$0.03	$18.7
2028	$16.5	$0.03	$16.5
2029	$18.7	$0.02	$18.8
2030	$18.7	$0.02	$18.7
2031	$17.6	$0.02	$17.7
2032	$17.6	$0.02	$17.6
2033	$15.6	$0.02	$15.6
2034	$13.8	$0.02	$13.8
2035	$14.2	$0.01	$14.2
2036	$12.9	$0.01	$12.9
2037	$12.8	$0.01	$12.8
2038	$12.6	$0.01	$12.6
2039	$11.2	$0.01	$11.2
2040	$10.1	$0.01	$10.1
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$34.00**	**$0.05**	**$34.04**

As described above, our analysis incorporates the change in coal transportation costs into our assessment of welfare effects. Our analysis suggests that these costs decline under the Proposed Rule because, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers. This reduction in transportation costs represents approximately 35 percent of compliance costs under the Proposed Rule over the 2020-2040 period.

The estimated welfare losses presented in Exhibit 5-13 are less than the compliance costs presented in Chapter 4. This reflects the inclusion of transportation cost impacts in our analysis of market welfare losses; changes in transportation costs were not captured in the compliance cost analysis in Chapter 4. As noted above, we estimate that, on average, the production cost impacts of the Proposed Rule are less significant for coal producers located near coal consumers. Thus, we expect that production will shift to these producers, lowering the resources expended on coal transportation. The deadweight loss represented by areas F and G in Exhibit 5-2 does not outweigh this reduction in transportation costs, as the projected decline in coal production under the Proposed Rule is quite small.

The estimated welfare losses presented in Exhibit 5-13 reflect no stranding of coal reserves. As discussed above, based on the various provisions included in the Proposed Rule, we estimate that all coal that is recoverable under the baseline is also recoverable under the Proposed Rule.

5.5 LIMITATIONS AND UNCERTAINTIES

Our analysis of the welfare effects associated with the Proposed Rule involved several methodological choices and assumptions that may have introduced a number of uncertainties into the analysis. The most significant of these are summarized in Exhibit 5-14.

EXHIBIT 5-14. TREATMENT OF KEY UNCERTAINTIES IN THE COAL MARKET WELFARE ANALYSIS

UNCERTAINTY	TREATMENT OF UNCERTAINTY
Model Mine Uncertainty: The assessment of market welfare effects presented in this chapter relies on cost impacts derived from the model mines analysis presented in Chapter 4. The uncertainties described in that chapter apply to the welfare analysis as well.	As described in Chapter 4, we developed several different model mines to derive as rich a representation as was practicable of the diversity in coal mine operations.
Market Model Uncertainty: The suite of models that we employ to assess changes in coal production and pricing under the Proposed Rule include a rich representation of coal market dynamics. Nevertheless, as a stylized representation of these markets, the EVA models may not capture variables that are difficult to observe and/or measure (e.g., coal production costs by mine). In addition, the model relies on several exogenous forecasts, any of which may affect model results (e.g., GDP growth, the strength of the U.S. dollar, etc.). The impact of these uncertainties on the results of our analysis is unknown.	To minimize uncertainty, the EVA models rely on disaggregated data (e.g., for individual power plants) where possible to capture the likely response of regulated entities.
Assumed linearity of coal supply and demand functions: As described above, our estimation of the producer and consumer surplus losses associated with the Proposed Rule assumes that the supply and demand functions for coal are linear. In reality these functions may be non-linear (e.g., supply functions are often specified as convex).	Given the constant increase in production costs per ton assumed in Chapter 4 and the small changes in coal production under the Proposed Rule, the assumption of linearity is unlikely to have a significant impact on our results.

CHAPTER 6 | REGIONAL ECONOMIC IMPACTS ANALYSIS

This chapter describes anticipated regional economic changes forecast under the Proposed Rule. These changes are relative to the baseline scenario, which forecasts economic conditions absent the rule. These regional economic measures provide insights into the distributional effects of the rule, and address regional disruptions (and benefits) associated with the rule that may not be captured in national market welfare measures.

6.1 SUMMARY OF FINDINGS

Predicting and tracking specific employment effects of this Proposed Rule is difficult to disentangle from other ongoing economic and technological trends. The reaction of the labor market to increased regulation is complex.[137] As such, anticipating the future response of the coal industry to the Proposed Rule is challenging. Compliance costs of the Proposed Rule are anticipated to result in changes to regional coal industry employment that will be added to and combined with ongoing trends. Our analysis is undertaken as follows:

1. We estimate the changes (losses) in direct employment demand that are anticipated to result from changes (reductions) in future coal production due to the Proposed Rule relative to the baseline forecast. These "production-related employment effects" are losses that are expected to be associated with coal that will *not* be produced because of the rule. We calculate this by combining forecast changes in annual coal production with recent worker productivity data (employment per ton of coal produced). Since the Proposed Rule is expected to reduce the volume of coal produced, we forecast a reduction in employment demand due to this factor. These effects are measured in full time equivalents (FTEs i.e., one full time worker employed for one year). Between 2020 and 2040, production-related reductions in annual employment demand are anticipated to vary from 41 to 590 jobs below baseline projections, depending on the year of analysis, with an average annual loss of 260 jobs.

2. We also estimate some change in economic activity associated with expenditures by the coal industry on compliance with the rule. In general, these effects are positive, as the rule, while experienced as a cost to the industry, generates demand for local goods and services. These "compliance-related employment effects" stem from increased expenditures on compliance activities, including haulage, stream restoration, reforestation, and administrative costs. These activities are expected to increase demand for labor as a result of the rule. The

[137] Morgenstern, R. D. 2015. Jobs and Environmental Regulation. PowerPoint presentation for How Do Environmental Policies Affect Jobs? Resources for the Future. http://www.rff.org/Documents/Events/150506-EnviroPolicyJobs-Morgenstern.pdf

compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of the rule follow the pattern of overall forecast coal production. These additional work requirements include performing inspections, conducting biological assessments, and other tasks that require employment of highly trained professionals (e.g., engineers and biologists). Other increased work requirements associated with elements contained in the Proposed Rule are expected to require similar skills as currently utilized by the industry (e.g., bulldozer operations, haulage activities). Between 2020 and 2040, compliance-related annual employment demand increases are anticipated to vary from 210 to 270 jobs above baseline projections, depending on the year of analysis, with an average annual gain of 250 jobs.

3. We also estimate the impacts of the Proposed Rule on severance tax collection by states. For this analysis, we use state-specific projections of future changes in expected coal production from our coal market modeling, then apply state-specific methods for calculating severance taxes to approximate severance tax effects. These impacts are generally negative. As shown in Exhibit 6-1, annualized impacts to state severance taxes follow the general pattern of changes in production over the time period for the analysis, with total annualized reductions of severance taxes estimated at $2.9 million (discounted at seven percent) over the 21 year study period.

The impacts of the rule are expected to vary regionally, related both directly to rule effects and indirectly to industry responses to the rule. Year to year variation in rule effects are a function of the model of overall coal demand. We note that the overall scale of impacts that we are seeing are small relative to the size of the coal industry.

Note that our analysis focuses on presentation of direct regional economic impacts of the Proposed Rule stemming from changes in coal production and compliance-related costs. We do expect the Proposed Rule to generate indirect and induced effects, which are discussed qualitatively. We also do not include regional economic effects that could be associated with downstream changes related to increased demand for other sources of energy, such as a possible increased demand for natural gas. While displaced coal demand could increase natural gas demand and associated regional economic activity, these offsetting impacts are uncertain and are not estimated. Additionally, we do not include regional economic impacts associated with increases in electricity costs (as described in Chapter 9). These impacts could be manifested by changes in consumer spending patterns, but regional impacts of these changes are too uncertain to quantify.

EXHIBIT 6-1. SUMMARY OF ANNUAL REGIONAL ECONOMIC IMPACTS OF THE PROPOSED RULE, 2020-2040

COAL REGION	PRODUCTION-RELATED EFFECTS ON EMPLOYMENT, FTE[1] (AVERAGE[3], RANGE[4])	COMPLIANCE-RELATED EFFECTS ON EMPLOYMENT, FTE[2] (AVERAGE, RANGE)	TOTAL EFFECTS ON INCOME, MILLIONS OF DOLLARS (AVERAGE, RANGE)	SEVERANCE TAXES (ANNUALIZED, 2020-2040)
Appalachian Basin	(210) (450) - (41)	120 97 - 120	($7.7) ($27) - $5.1	($1,940,000)[5]
Colorado Plateau	0 0 - 1	14 12 - 15	$1.1 $1.0 - $1.2	$790
Gulf Coast	0 (3) - 2	30 30 - 31	$2.5 $2.3 - $2.6	$0
Illinois Basin	(33) (91) - 0	66 52 - 76	$2.7 ($1.2) - $4.7	($567,000)[5]
Northern Rocky Mountains and Great Plains	(22) (66) - 0	21 19 - 22	($0.1) ($4.2) - $1.8	($431,000)
Northwest	0 0 - 0	1 1 - 1	$0.04 $0.04 - $0.04	$0
Western Interior	0 0 - 0	3 3 - 3	$0.2 $0.2 - $0.2	$0
National	**(260)** **(590) - (41)**	**250** **210 - 270**	**($1.2)** **($28) - $15**	**($2,940,000)**

[1] Production-related employment effects are reported as an average and a range of expected annual effects. Employment effects from production are calculated using employment per ton of coal produced. The range of employment effects represent the minimum and maximum effect in any year in the study period when impacts on surface mining as well as underground mining employment are combined.

[2] Compliance-related employment effects are reported as an average and a range of expected annual effects. Employment effects from compliance are calculated using expected changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance The range of employment effects represent the minimum and maximum effect in any year in the study period.

[3] "Average" is the average annual effect of the Proposed Rule over the study period for the analysis on employment (2020-2040).

[4] "Range" is the minimum and maximum effect on employment in any year in the study period.

[5] Production in Kentucky is evenly divided between the Appalachian Basin and Illinois Basin regions.

6.2 INTRODUCTION

For regulations that may impose a burden on specific geographic areas within the U.S., regional economic impact analysis can provide an assessment of the potential localized effects. In this chapter, we examine the regional economic changes forecast to occur as a result of the Proposed Rule. In general, "regional economic impacts" describe changes in the flow of money throughout the economy due to a new project or policy. These changes can be measured as total dollars, as specific types of spending (e.g., on wages for employees), as employment demand, and as tax effects.

The relationship between environmental regulation and employment is a subject being debated within the academic literature. As developed in this chapter and as supported by economic theory, environmental regulation can increase production costs, which raises prices, reduces demand, and ultimately puts downward pressure on employment. However, compliance with environmental regulation also typically introduces additional labor requirements, which may mitigate that effect. Several studies on this topic have found that environmental regulation has a slightly positive overall impact, if any, on employment.[138] Our analysis focuses on forecasting regional economic effects of the Proposed Rule, as measured by expected changes in economic activity, or expenditure patterns, in affected coal regions. Forecast shifts in the geographic distribution of coal production, the manner in which coal is produced (e.g., surface versus underground), and the total quantity of coal produced, are expected to lead to changes in regional coal industry employment, even absent the Proposed Rule. We describe and assess the impacts of the Proposed Rule using the following key metrics:

- **Employment Demand** primarily measures the change in the number of employees needed for the production of coal in this analysis. In addition, it includes changes in demand for labor associated with the compliance requirements of the rule. Employment demand is measured in full time equivalents (FTEs).[139]
- **Labor Income** is a measure of the employment income received in coal regions as part of the employment demand, and includes wages, benefits, and proprietor income.
- **Severance Taxes** are taxes collected by states on coal production.

We estimate the direct effects of compliance requirements and changes in coal production on employment demand and labor income in this analysis. In addition to these direct effects, "ripple" impacts are also likely to occur associated with 1) changes in spending

[138] Berman, E. and Bui, L.T.M. 2001. "Environmental Regulation And Productivity: Evidence From Oil Refineries," The Review of Economics and Statistics, MIT Press 83(3): 498-510; Morgenstern, R.D., Pizer, W.A., and Shih, J.S. 2002. Jobs Versus the Environment: An industry-Level Perspective. Journal of Environmental Economics and Management 43:412-436; Bezdek, R.H., Wendling, R.M., and DiPerna, P. 2008. Environmental protection, the economy, and jobs: National and regional analyses. Journal of Environmental Management 86: 63-79; Belova, A., Gray, W., Linn, J., and Morgenstern, R, 2013. Environmental Regulation and Industry Employment: A Reassessment. U.S. Census Bureau Center for Economic Studies Paper No. CES-WP-13-36.

[139] IMPLAN measure employment as is the annual average of monthly jobs in an industry, and for purposes of this analysis, is nearly equivalent to an FTE. This discussion uses FTE as a metric given it's more widely understood use.

by local industries buying goods and services from other local industries (sometimes called indirect effects), as well as 2) changes in household consumption arising from changes in employment and associated income. We recognize the existence of these effects but do not quantify these in this analysis due to the high level of uncertainty associated with quantifying the scale of these effects.

6.3 PRODUCTION-RELATED EMPLOYMENT EFFECTS

This section considers the potential for the rule to affect employment in the coal mining industry (i.e., direct employment impacts). The primary mechanisms by which the Proposed Rule may affect regional employment in the coal sector are:

1. **If future regional coal production is reduced**. This outcome could result if (a) reserves are stranded by the rule, or (b) cost requirements of the rule result in price changes that in turn result in production shifts. Under the Proposed Rule, reserves are not expected to be stranded, but some price shifts are expected. Individual coal regions may experience either an increase or decrease in mining-related employment, depending on how production levels shift between coal regions.

2. **If the rule causes a change in the mining type (surface or underground).** To the extent rule requirements or associated cost increases lead to an overall shift from surface mining to underground mining, employment opportunities are expected to increase as underground mining is generally more labor-intensive than surface mining, all else being equal.

In addition to the direct employment effects within the mining industry, a change in the regional distribution of coal production may also affect employment in industries that provide goods and services to the coal industry or that otherwise rely on mined coal. To the extent that coal production decreases in a particular region, employment in these secondary industries would also be expected to decline. In addition, employment in other energy sector industries could increase due to a shift toward substitute fuels (e.g., natural gas) to generate electricity. While increased natural gas demand could result in increased regional economic activity, the location and magnitude of such impacts are uncertain. In aggregate, coal production-related effects associated with the Proposed Rule are negative, as overall coal production is expected to decline.

The analysis of employment impacts estimates the effect of the Proposed Rule on employment in each of the coal regions for the 21-year period of study, from 2020 to 2040. This analysis incorporates employment and production data released in the 2012 EIA Annual Coal Report. The following steps provide estimates of employment impacts by region:

1. **Derive employment-to-production coefficients.** The first step involves relating production levels and employment for each region and mine type. Because the coal industry, and Appalachia in particular, generally experienced a

trend of decreasing labor productivity in recent years,[140] data from the single most recent year, 2013, was used as the best approximation of future labor employment per ton of coal produced. Furthermore, instead of using the industry average, we calculate the productivity average of the bottom quartile active mines by region. We assume that these mines are representative of the mines likely to experience reduced production.

2. Apply coefficients to production forecasts. Next, we apply our calculated employment coefficients to forecasts of coal production by region and mine type under the Proposed Rule (See Chapter 3 and Appendix F). Multiplying expected annual workers per ton of coal produced by the forecast of regional coal production gives an estimate of future employment within the coal mining industry under the Proposed Rule. The difference between baseline regional employment projections and employment projections under the Proposed Rule are the expected production-driven employment effects of the rule.

DERIVATION OF EMPLOYMENT-TO-PRODUCTION COEFFICIENTS

Exhibit 6-2 presents total employment for 2012 in the coal industry by region and mine type. Exhibit 6-3 presents employment for 1998 to 2012 by region. Here, the "coal industry" includes all employees engaged in production, preparation, processing, development, maintenance, repair shop, or yard work at mining operations, including office workers. As shown, the majority of direct employment is in the Appalachian Basin, which is not surprising given the large number of mines in that region (see Chapter 2).

In order to estimate changes in employment expected as a result of changes to forecast coal production in each region, we must understand the relationship between coal production and employment in the industry. This section examines current worker productivity (typically measured in terms of production per employee per hour), by relating historical production levels to coal industry employment for each region and mine type. By dividing the average number of employees in 2013 in the coal industry by the 2013 coal production, we can calculate annual coefficient that describes the employment required per ton of coal produced by region.[141] As shown in Exhibit 6-4, extraction of coal from surface mines in the Appalachian Basin and the Western Interior is relatively labor-intensive (i.e., high employment required per ton of coal produced), as individual mines are typically small and/or located on mountainous terrain. For context, we also present productivity from the perspective of production per employee per hour in Exhibit 6-5. As shown, labor-intensive areas (areas with high employment to production coefficients such as the Appalachian Basin) exhibit lower productivity per worker per hour.

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[140] According to EIA's 2012 Annual Coal Report, average production per employee hour decreased by 0.2 percent from 2011; reaching a level of 5.19 short tons per employee hour in 2012 (U.S. EIA. 2013a. Annual Coal Report 2012. Table 21: Coal Productivity by State and Mine Type, 2012 and 2011. U.S. Department of Energy.).

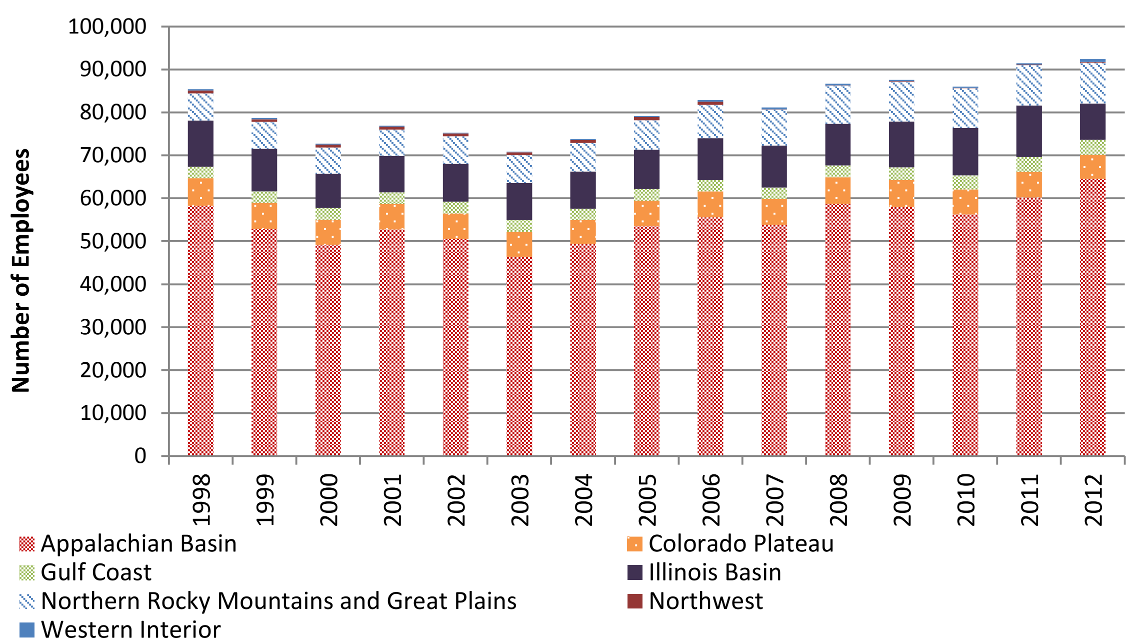
[141] As the most accessible coal is harvested, worker productivity typically declines over time despite technological improvements (employment per ton of coal produced increases). We use recent data on productivity as a proxy for future productivity. To the extent that productivity continues to decline over time (employment per ton of coal produced increases), our estimates of lost employment related to decreased production could be understated.

EXHIBIT 6-2. COAL INDUSTRY EMPLOYMENT BY COAL REGION AND MINE TYPE, 2012

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	17,779	39,850	57,629
Colorado Plateau	1,796	4,043	5,839
Gulf Coast	3,399	0	3,399
Illinois Basin	3,113	9,838	12,951
Northern Rocky Mountains and Great Plains	8,895	570	9,465
Northwest	143	0	143
Western Interior	185	125	310
Total	35,310	54,426	89,736

Source: U.S. EIA. 2013a
Note: Includes all employees engaged in production, preparation, processing, development, maintenance, repair shop, or yard work at mining operations, including office workers. Excludes preparation plants with fewer than 5,000 employee hours per year, which are not required to provide data.

EXHIBIT 6-3. AVERAGE ANNUAL COAL INDUSTRY EMPLOYMENT, 1998-2012



Source: U.S. EIA, Annual Coal Reports 1998 – 2012 (EIA-0584).
Note: Employment includes all employees engaged in production, preparation, processing, development, maintenance, repair shop, or yard work at mining operations, including office workers for 1998 forward. For 1997 and prior years, employment includes mining operations management and all technical and engineering personnel, excluding office workers. Employment excludes preparation plants with fewer than 5,000 employee hours per year, which are not required to provide data.

From Exhibits 6-4 and 6-5, we observe that a small change in coal production could lead to a relatively large change in employment demand in regions that are relatively labor-intensive, such as in the Appalachian Basin. Surface mines in the Colorado Plateau, Gulf Coast, and Northern Rocky Mountains and Great Plains regions are typically larger and located on flatter terrain, and have greater productivity rates per employee. In all five coal regions that support underground mining activity, underground mining is more labor-intensive than surface mining (i.e., more employee hours are required to produce the same amount of coal). Underground mines in the Northern Rocky Mountains and Great Plains region produce coal most efficiently with respect to labor demands among the seven coal regions. All else equal, forecast reductions in coal production in labor-intensive areas (e.g., Appalachia) would result in relatively more impacts to employment than would reductions in production in low-labor requirement areas (e.g., Northern Rocky Mountains and Great Plains).

EXHIBIT 6-4. EMPLOYMENT IN COAL INDUSTRY PER MILLION TONS OF COAL PRODUCED, 2013

COAL REGION	SURFACE	UNDERGROUND
Appalachian Basin	246.2	299.1
Colorado Plateau	77.9	109.5
Gulf Coast	99.8	NA
Illinois Basin	108.3	169.8
Northern Rocky Mountains and Great Plains	31.3	67.2
Northwest	88.7	NA
Western Interior	261.9	305.5

Source: MSHA, 2013b.
Note: This figure is calculated using 2013 estimates of the employment per million tons produced. To be conservative (i.e., more likely to overstate than understate impacts), we then use the average of the least productive mines in each region that comprise at least 25 percent of total production in that region.

EXHIBIT 6-5. WORKER PRODUCTIVITY (AVERAGE PRODUCTION PER OPERATOR EMPLOYEE PER HOUR) (SHORT TONS), 2013

COAL REGION	SURFACE	UNDERGROUND
Appalachian Basin	2.0	1.6
Colorado Plateau	6.2	4.4
Gulf Coast	4.8	NA
Illinois Basin	4.4	2.8
Northern Rocky Mountains and Great Plains	15.4	7.16
Northwest	5.4	NA
Western Interior	1.8	1.6

Source: MSHA, 2013b.
Note: Derived from 2013 average workers per million tons of coal production. Assumes a single employee works 2080 hours per year.

In areas where coal production is anticipated to be reduced due to the rule, the Proposed Rule is also expected to decrease employment in industries that provide goods and services to mining operators throughout the production process. Affected entities include mining and construction equipment manufacturers, the coal transportation industry, coal processing facilities, and a variety of other local businesses located near mining operations in coal-producing regions. Decreased coal production would lower demand for these goods and services, thus decreasing income and employment in these support industries.

6.4 COMPLIANCE-RELATED EMPLOYMENT EFFECTS

Certain elements of the Proposed Rule may generate increases in employment demand from the mining sector through the introduction of additional monitoring and analytic requirements at mine sites, as well as earth-moving requirements. Specifically:

- **Baseline data collection analysis/monitoring during mining and reclamation.** These elements require additional sampling, data collection, and analysis of environmental parameters.
- **Activities in or near streams (including disposal of excess spoil and coal mine waste).** This element requires that operators demonstrate restoration of stream form and ecological function for all disturbed perennial and intermittent streams. Furthermore, this element requires more labor-intensive methods for excess spoil fill construction as well as daily monitoring of fill placement during fill construction.
- **Mining through streams.** This element requires additional analysis of the ecological and hydrologic effects of mining through and restoring streams, as well as more labor-intensive stream channel construction.
- **Surface configuration/approximate original contour (AOC) variance.** These elements require a more labor-intensive restoration process, and additional analysis of the effects of AOC variances on stream hydrology. The AOC variance

element also requires additional analysis of the effects of AOC variances on aquatic ecology and biological communities.

- **Revegetation and topsoil management.** This element requires more labor-intensive soil management and revegetation practices.
- **Fish and wildlife protection and enhancement.** This element requires mandatory fish and wildlife protection and enhancement measures to the extent that mining operations result in the long-term loss of native forest, loss of other native plant communities, or filling of a stream segment.

These additional work requirements include performing inspections, conducting biological assessments, and other tasks that require employment of highly trained professionals (e.g., engineers and biologists) as part of compliance with some elements of the Action Alternatives. Other increased work requirements associated with elements contained in the Action Alternatives are expected to require similar skills as currently utilized by the industry (e.g., bulldozer operations). In general, while some of the increased employment demand may utilize existing mining labor skills (e.g., requirements that require additional earth moving), other employment demand from Action Alternatives may require other types of labor (e.g., biological monitoring, lab testing, paperwork). That is, some additional jobs created by the Proposed Rule may differ in skill requirements from the production-oriented jobs that would be reduced due to decreased coal production.

6.5 IMPACTS OF COAL PRODUCTION CHANGES ON EMPLOYMENT AND LABOR INCOME

As described above, our analysis first estimates the direct employment demand changes attributable to the Proposed Rule due to anticipated changes in future coal production relative to the baseline forecast. Future coal production following rule implementation is modeled using a coal market model, as described in Chapter 2 and Appendix F. These impacts are described as the “production-related employment effects” impacts in Exhibits 6-6A and 6-7.

Next, we estimate the change in economic activity attributable to the cost of industry compliance with the rule. These impacts are described as the “compliance-related employment effects” impacts in in Exhibits 6-6A and 6-7.

As shown in Exhibit 6-6A, production-related annual impacts to employment across all regions are expected to range from a reduction in demand for 590 FTEs of labor to a reduction of 41 FTEs with an average annual decrease in demand for 260 FTEs of labor. Changes in compliance-related employment demand are expected to range from an annual gain of 210 to 270 FTEs. In the Appalachian Basin, production-related employment demand is expected to range from a reduction of 450 FTEs of labor to a reduction of 41 FTEs with an average annual reduction of 210 FTEs. On the other hand, compliance-related employment demand in the Appalachian Basin is expected to range from a gain of 97 to 120 FTEs. Impacts to labor income follow similar patterns, with the production-related effect on labor income ranging from a reduction of $50 million to a reduction of $3.4 million with an average reduction of $22 million nationally.

Compliance-related impacts to labor income are expected to range from an increase of $19 million to $22 million annually, with an average gain of $21 million nationally. In the Appalachian Basin production-related labor income is expected to range from a reduction of $37 million to a reduction of $3.4 million with an average reduction of $17 million. Compliance-related labor income effects in the Appalachian Basin are expected to range from an increase of $8.5 million to $10 million, with an average gain of $9.7 million nationally.

Estimated employment impacts vary from year to year and across regions. Exhibit 6-6A presents the average annual impacts of and the maximum and minimum annual impacts for the Proposed Rule.

- "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020 to 2040).
- "Range in any year" is the minimum and maximum effect on employment in any year in the study period
- "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.
- The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
- The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
- The range of effects to "Surface and Underground Combined" employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges
- "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

Exhibit 6-6B presents a line graph of the employment effects for the Proposed Rule for 2020 through 2040 by type of effect.

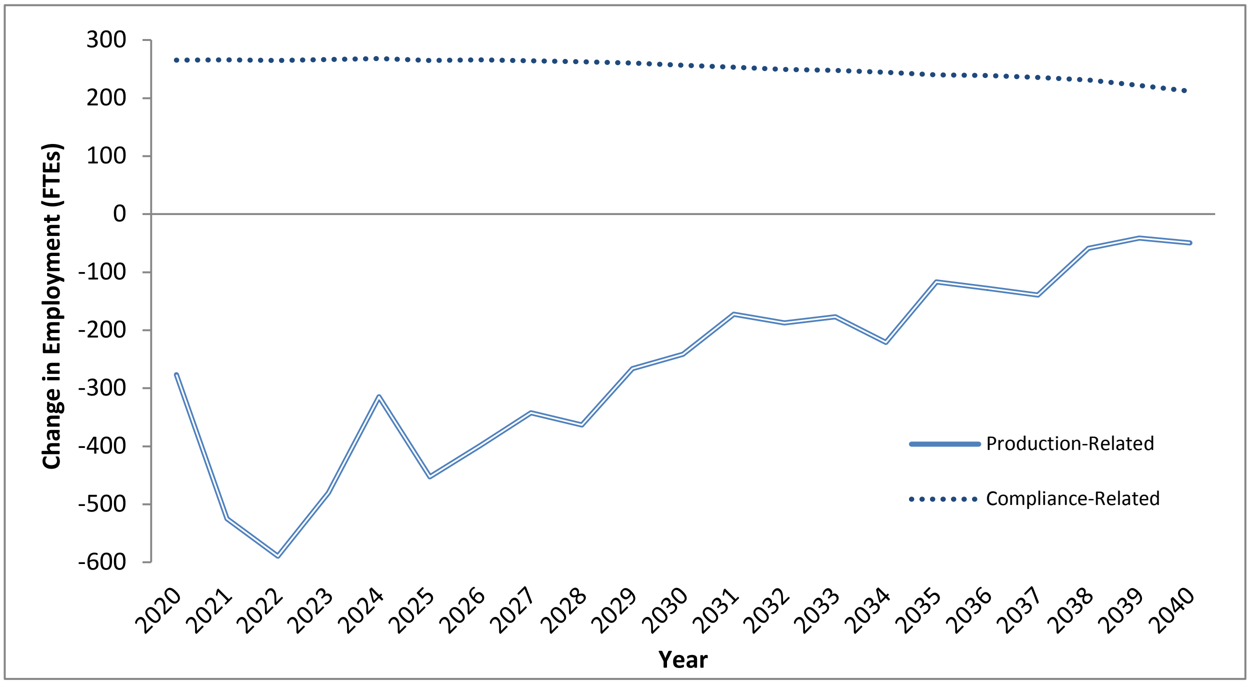
Because the IMPLAN model is static (i.e., it does not include a time element), it cannot examine impacts of increased costs or changes in production on long-term regional employment, value-added, or labor income. Thus, this analysis presents results for each region that show the range of the rule's potential incremental impacts (over and above what would be expected under the baseline), given current economic conditions, on these three factors in a given year over the timeframe for the analysis (see Appendix F for a presentation of production impacts and Chapter 4 for compliance costs by year). As shown in Exhibits 6-6A and 6-7, when the effects of additional compliance costs on labor demand by the coal industry are netted from the production-related employment effects, the results are negative or positive, depending on the year and region. To place these results in context, we note that a reduction of 324 FTEs represents less than a one percent decrease in the current national labor force in the industry. Exhibit 6-6C shows projected changes by region. Exhibit 6-6D displays projected employment (for 2020 to 2040) under the baseline as well as under the Proposed Rule for comparison.

EXHIBIT 6-6A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER THE PROPOSED RULE, 2020-2040 (FTES)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(65)	(140)	(210)	120
	Range in any year:[2]	(140) – (15)	(310) - (24)	(450) - (41)	97 – 120
Colorado Plateau	Average over 21 years:	0	0	0	14
	Range in any year:	0 - 0	0 - 1	0 - 1	12 – 15
Gulf Coast	Average over 21 years:	0	0	0	30
	Range in any year:	(3) - 2	0 - 0	(3) – 2	30 – 31
Illinois Basin	Average over 21 years:	(6)	(27)	(33)	66
	Range in any year:	(19) - 0	(73) - 0	(91) - 0	52 – 76
Northern Rocky Mountains and Great Plains	Average over 21 years:	(22)	0	(22)	21
	Range in any year:	(66) – 0	0 –0	(66) – 0	19 – 22
Northwest	Average over 21 years:	0	0	0	1
	Range in any year:	0 - 0	0 – 0	0 – 0	1 – 1
Western Interior	Average over 21 years:	0	0	0	3
	Range in any year:	0 - 0	0 – 0	0 – 0	3 – 3
TOTAL	**Average over 21 years:**	**(93)**	**(170)**	**(260)**	**250**
	Range in any year:	**(220) - (17)**	**(370) - (24)**	**(590) - (41)**	**210 - 270**

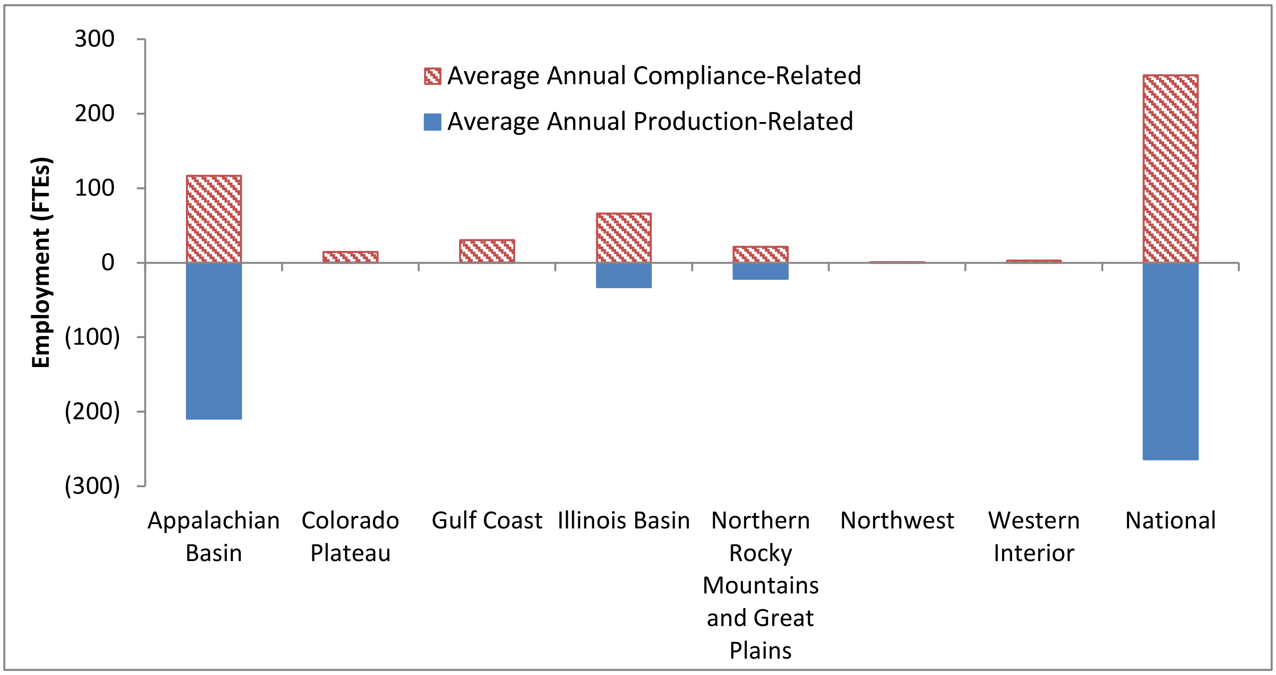
[1] "Average over 21 years" is the average annual effect of the Proposed Rule over the study period for the analysis on employment (2020-2040).
[2] **"**Range in any year" is the minimum and maximum effect on employment in any year in the study period.
[3] **"**Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Proposed Rule. These are calculated using assumptions related to employment per ton of coal produced.
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
[5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Proposed Rule on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] **"**Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 6-6B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER THE PROPOSED RULE COMPARED TO BASELINE, BY TYPE OF EFFECT, (2020 TO 2040)



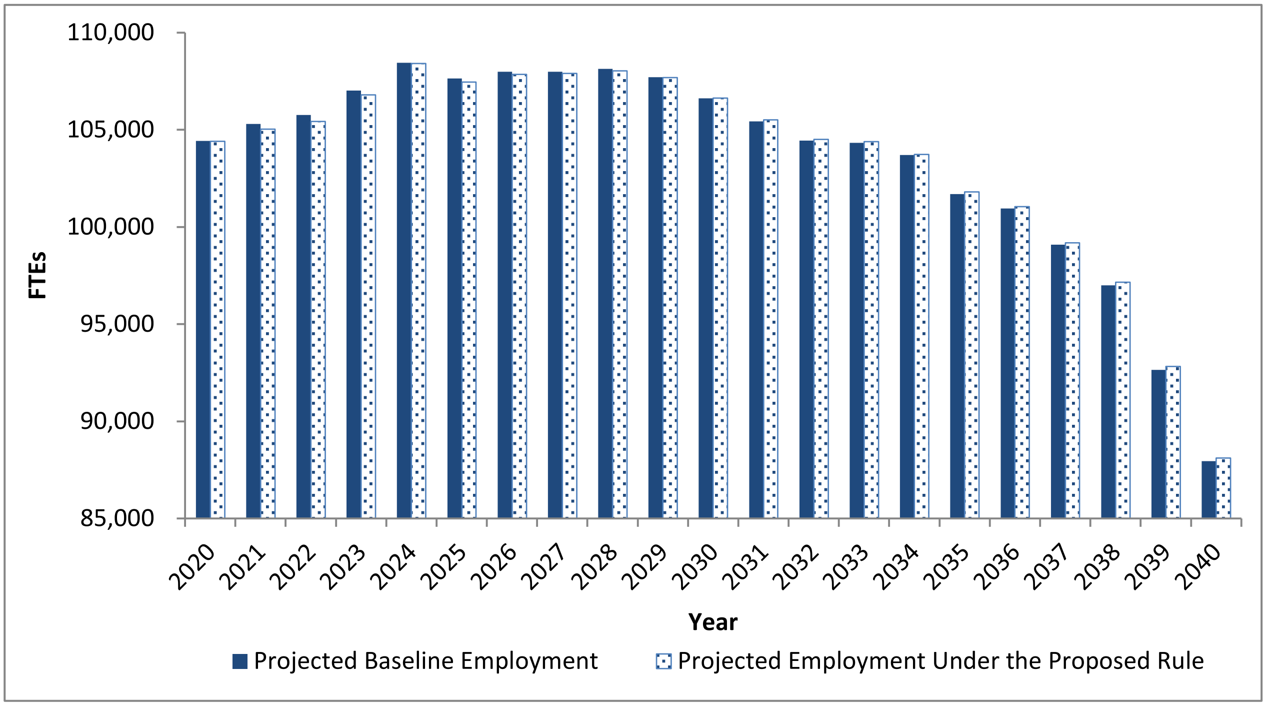
Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of the Proposed Rule. These are calculated using assumptions related to employment per ton of coal produced. **"**Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 6-6C. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER THE PROPOSED RULE COMPARED TO BASELINE, BY REGION, (2020 TO 2040)



Notes: "Average Annual Compliance-Related" are effects on employment associated with expenditures on compliance-related activities that are expected as a result of the Proposed Rule, averaged over the study period by region. These are calculated using assumptions related to employment demand per dollar spent on compliance. "Average Annual Production-Related" are effects on employment associated with changes to coal production that are expected as a result of the Proposed Rule, averaged over the study period by region. These are calculated using assumptions related to employment per ton of coal produced.

EXHIBIT 6-6D. ANNUAL COAL INDUSTRY EMPLOYMENT UNDER BASELINE CONDITIONS AND THE PROPOSED RULE, FTES, 2020 TO 2040



Notes: As shown, coal industry employment is projected to decrease by over 15,000 FTEs under baseline conditions, i.e., due to factors unrelated to the Proposed Rule. We also note that the coefficient used to estimate employment impacts in our analysis leads to a somewhat greater estimate of total industry employment than is reported in some sources. For example, EIA's 2012 Annual Coal Report estimates 2012 coal industry employment to be approximately 90,000 employees (U.S. EIA. 2013a). The employment multipliers we use in the production-related impacts analysis are conservative—specifically, we use the average of the least productive mines in each region that comprise at least 25 percent of total production in that region. Using this multiplier to present the total forecast employment level for the industry therefore overestimates the total level of coal industry employment in this exhibit. The baseline number of employees is presented for display purposes--the focus of our analysis is on incremental effects.

EXHIBIT 6-7. ANNUAL LABOR INCOME CHANGES UNDER THE PROPOSED RULE (MILLIONS OF DOLLARS)

COAL REGION	METRIC	PRODUCTION-RELATED INCOME EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED INCOME EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED INCOME EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED INCOME EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	($5.4)	($12)	($17)	$9.7
	Range in any year:[2]	($12) - ($1.3)	($26) – ($2.0)	($37) – ($3.4)	$8.5 - $10
Colorado Plateau	Average over 21 years:	$0	$0.02	$0.02	$1.1
	Range in any year:	$0 – $0.01	($0.02) – $0.1	($0.02) – $0.06	$1.0- $1.2
Gulf Coast	Average over 21 years:	$0	$0	$0	$2.5
	Range in any year:	($0.3) - $0.1	$0 - $0	($0.3) - $0.1	$2.5 - $2.5
Illinois Basin	Average over 21 years:	($0.5)	($2.2)	($2.7)	$5.5
	Range in any year:	($1.6) - $0.01	($6.0) - $0.03	($7.5) - $0.04	$4.6 - $6.3
Northern Rocky Mountains and Great Plains	Average over 21 years:	($2.1)	($0.01)	($2.1)	$2.0
	Range in any year:	($6.3) - ($0.03)	($0.02) – ($0.01)	($6.3) – ($0.04)	$1.8 - $2.1
Northwest	Average over 21 years:	0	0	0	$0.04
	Range in any year:	0-0	0-0	0-0	$0.04 - $0.04
Western Interior	Average over 21 years:	0	0	0	$0.2
	Range in any year:	0-0	0-0	0-0	$0.2 - $0.2
U.S. TOTAL	**Average over 21 years:**	($8.0)	($14)	($22)	$21
	Range in any year:	($19) - ($1.5)	($31) – ($2.0)	($50) – ($3.4)	$19 - $22

[1] "Average over 21 years" is the average annual effect of the Proposed Rule over the study period for the analysis on income (2020-2040).
[2] "Range in any year" is the minimum and maximum effect on income in any year in the study period.
[3] "Production-related income effects" are calculated as effects associated with changes to coal production that are expected as a result of the Proposed Rule. These are calculated using assumptions related to employment and wages per ton of coal produced.
[4] The range of income effects for Surface mining represents the minimum and maximum effect in any year in the study period.
[5] The range of income effects for Underground mining represents the minimum and maximum effect in any year in the study period.
[6] The range of income effects for Surface and Underground mining combined represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Proposed Rule on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] "Compliance-related income effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand and wages per dollar spent on compliance.

As described above, the relationship between environmental regulation and employment is a subject being debated within the academic literature.[142] This literature suggests that the findings in this chapter are consistent with current research on the impact of environmental regulation in general. It should be noted, however, that the literature does not specifically address the relationship between environmental regulation and labor demand in extractive industries such as coal mining.

SEVERANCE TAX EFFECTS

Severance tax revenue for a state is directly related to coal mining activity. Thus, regulatory alternatives that reduce production in a given region will result in reduced tax revenue. Conversely, increased coal production would generate increased revenue. The relationship between coal production and tax revenue is complicated in some states. For example, some states only tax certain types of coal extracted or offer credits for particular extraction methods. For this reason, this analysis undertakes the following method to estimate impacts of the regulatory alternatives on state tax revenues:

1. **Deriving effective tax rates.** The first step involves examining state tax codes for coal severance taxation rates. For some states, the severance tax rate is a simple dollar-per-ton multiplier, but many states vary the tax rate for different types of coal mining or provide tax credits and exemptions to certain types of mining. Some states calculate severance tax based on the gross value of severed coal.

2. **Applying effective tax rates to production forecasts.** The second step involves multiplying the effective tax rates to estimates of future production for each state. The difference between estimated severance tax revenues under the alternatives and baseline revenue forecasts represents the impact of the Proposed Rule to state severance tax revenues.

3. **Deriving annualized impacts.** The final step involves calculating the present value of tax revenue impacts in 2014 dollars, and annualizing the present value over the entire period of study. The analysis uses discount rates of three and seven percent (see Appendix G).

The states with the most coal production generally collect the most tax revenue on coal severance. Exhibit 6-8 reports 2012 coal severance tax revenues by state. The majority of tax revenue levied on coal severance in these years was collected by the top three coal-producing states, Wyoming, West Virginia, and Kentucky.

[142] Berman, E. and Bui, L.T.M. 2001. "Environmental Regulation And Productivity: Evidence From Oil Refineries," The Review of Economics and Statistics, MIT Press 83(3): 498-510; Morgenstern, R.D., Pizer, W.A., and Shih, J.S. 2002. Jobs Versus the Environment: An industry-Level Perspective. Journal of Environmental Economics and Management 43:412-436; Bezdek, R.H., Wendling, R.M., and DiPerna, P. 2008. Environmental protection, the economy, and jobs: National and regional analyses. Journal of Environmental Management 86: 63-79; Belova, A., Gray, W., Linn, J., and Morgenstern, R, 2013. Environmental Regulation and Industry Employment: A Reassessment. U.S. Census Bureau Center for Economic Studies Paper No. CES-WP-13-36.

Exhibit 6-9 presents tax rates on coal severance by state. For each state, an attempt was made to use reported tax rates to estimate 2012 severance tax revenue based on 2012 production levels. These estimates were then compared with actual 2012 severance tax revenues collected by each state. For states where estimates were accurate within a ten percent error bound, the analysis uses reported tax rates to estimate future severance tax revenues based on production projections. States where estimated 2012 severance tax revenues differed by more than ten percent from actual revenues generally have complicated tax provisions that make it difficult or impossible to forecast future revenues based on reported tax rates. For these states, the analysis uses an alternate production-to-tax-revenue multiplier calculated by dividing 2012 severance tax revenues by 2012 production levels. Exhibit 6-9 also presents the estimated tax rates used in this analysis for each state to estimate future tax revenues collected on coal severance.

Exhibit 6-10 reports total estimated severance tax revenue impacts over the entire period of study by state, discounted to 2014 dollars at a seven percent discount rate. In total, the analysis predicts an annualized decline in severance tax revenues of $2.5 million, across all coal producing states. West Virginia and Kentucky are estimated to bear over 80 percent of the lost severance tax revenues. These estimates are conservative for West Virginia and Kentucky as they are based on historic per-ton tax revenues while West Virginia and Kentucky severance taxes are based on the price of coal. As coal prices are expected to increase during the study period due to the Proposed Rule, the coal severance tax impacts of the Proposed Rule are likely to be less than estimated here for West Virginia and Kentucky.

EXHIBIT 6-8. COAL SEVERANCE TAX REVENUES COLLECTED BY STATE, 2012 (MILLIONS OF DOLLARS)

STATE	2012
Appalachian Basin	
Alabama[1]	$3.5
Kentucky[2]	$2.8
Maryland	$0
Ohio[2]	$5.6
Pennsylvania	$0
Tennessee[2]	$1.0
Virginia	$0
West Virginia[2]	$460
Colorado Plateau	
Arizona	$0
Colorado[2]	$9.8
New Mexico	$11
Utah[2]	$0
Gulf Coast	
Louisiana	$0.48
Mississippi[2]	$0
Texas	$0
Illinois Basin	
Illinois	$0
Indiana	$0
Kentucky[2]	$280
Northern Rocky Mountains and Great Plains	
Montana[2]	$53
North Dakota	$11
Wyoming	$290
Northwest	
Alaska[2]	$41
Western Interior	
Arkansas	$0.01
Kansas[2]	$8.8
Missouri	$0
Oklahoma	$0
Total U.S.	**$1,200**

STATE	2012
Notes: Sources: U.S. Census Bureau 2012 Annual Survey of State Government Tax Collections; Individual state revenue reports. [1] Coal severance tax revenues are reported for the fiscal year ending September 30, 2012. Total state tax revenues are reported for the calendar year ending December 31, 2012. The contribution of coal severance taxes to total taxes is calculated using data from varying timeframes. [2] Coal severance tax revenues are reported for the fiscal year ending June 30, 2012. Total state tax revenues are reported for the calendar year ending December 31, 2012. The contribution of coal severance taxes to total taxes is calculated using data from varying timeframes. - Coal severance tax revenues listed for New Mexico are net of the Intergovernmental Tax Credits (ITC) afforded to taxed coal entities. Severance tax revenues listed for Alaska consist of revenue from Alaska's mining license tax. We were unable to separate the value of severance tax revenues between the two regions in Kentucky (Illinois Basin and Appalachia) and Colorado (Northern Rocky Mountain and Great Plains and Colorado Plateau). We present the total value for the entire state. In Virginia no state tax is levied, but local areas may impose taxes on coal extracted within limits set by state law. Coal severance taxes for West Virginia are calculated as General Revenue Fund, Infrastructure Fund, and Local Dedication from Coal Severance tax figures provided for FY 2012 by the West Virginia Department of Revenue.	

EXHIBIT 6-9. REPORTED COAL SEVERANCE TAX RATES BY STATE, 2012

STATE	SEVERANCE TAX TYPE	RATE	ASSUMED RATE
Appalachian Basin			
Alabama[1]	State Coal Severance Tax	$0.335 per ton for the state.	$0.335 per ton
	Local Coal Severance Tax	$0.20 per ton in Jackson and Marshall County.	
Kentucky[1]	Coal Severance and Processing Tax	4.5% of gross value with a minimum tax of $0.50 per ton. A credit is given to thin seam coal extraction on a scale from 2.25% to 3.75% of the coal value.	$3.00 per ton for surface production and $2.88 per ton for underground production.
Maryland	No Coal Severance Tax	NA	
Ohio[1]	Coal Severance Tax	Base rate of $0.10 per ton, plus an additional $0.012 per ton on surface mined coal. An additional $0.12 to $0.16 per ton is levied on operations without a full cost bond and changes based on the amount remaining in the state Reclamation Forfeiture Fund at the end of each state budget biennium.	$0.252 per ton for surface production and $0.24 per ton for underground production.
Pennsylvania	No Coal Severance Tax	NA	
Tennessee[1]	Coal Severance Tax	$0.75 per ton on entire production of coal products in the state, regardless of place of sale or outside-of-state delivery.	$0.75 per ton
Virginia	Local Coal Reclamation Tax	Any county or city may impose a severance tax on all coal within its jurisdiction. The rate of tax shall not exceed 1% of the gross receipts from such coal or gases.	
West Virginia[2]	Natural Resources Severance Tax	5% of gross value, with the following reduced rates for thin seam underground mining: 2% of gross value for seams with thickness between 37 and 45 inches and 1% of gross value for seams with thickness less than 37 inches.	$3.757 per ton
Colorado Plateau			
Arizona	No Coal Severance Tax	NA	
Colorado[2]	Coal Severance Tax	$0.842 per ton.	$0.542 per ton.
New Mexico[1]	Coal Severance Tax	$0.57 per ton on surface coal and $0.55 per ton on underground coal. The state also imposes a surtax on coal, which is increased on July 1 each year. The surtax in effect in Fiscal Year 2009 was $0.83 per ton. Post-2011 renegotiated contracts are not subject to the surtax.	$1.40 per ton for surface production and $1.38 per ton rate for underground production ($0.57/$0.55 per ton rate plus $0.83 per ton surtax).*

EXHIBIT 6-9. REPORTED COAL SEVERANCE TAX RATES BY STATE, 2012

STATE	SEVERANCE TAX TYPE	RATE	ASSUMED RATE
Utah	No Coal Severance Tax	NA	
Gulf Coast			
Louisiana[1]	Natural Resources Severance Tax	$0.12 per ton of lignite.	$0.12 per ton
Mississippi	No Coal Severance Tax	NA	
Texas	No Coal Severance Tax	NA	
Illinois Basin			
Illinois	No Coal Severance Tax	NA	
Indiana	No Coal Severance Tax	AN	
Kentucky[1]	Coal Severance and Processing Tax	4.5% of gross value with a minimum tax of $0.50 per ton. A credit is given to thin seam coal extraction on a scale from 2.25% to 3.75% of the coal value.	$3.00 per ton for surface production and $2.88 per ton for underground production.
Northern Rocky Mountains and Great Plains			
Montana[2]	Coal Severance Tax	Heat Content / Surface / Auger / Underground <7,000 BTU / 10% of value / 3.75% of value / 3% of value 7,000 BTU / 15% of value / 5% of value / 4% of value	$01.437 per ton
North Dakota[1]	Coal Severance Tax	$0.375 per ton plus $0.02 per ton for the Lignite Research Fund. Reduced rates apply to coal used in cogeneration facilities. No tax on coal used for the following: (1) to heat state buildings; (2) used by the state or political subdivision of the state; or (3) agricultural processing.	$0.395 per ton
Wyoming[1]	Coal Severance Tax	7% of taxable valuation of surface coal and 3.75% of taxable valuation of underground coal, with a maximum tax of $0.60 per ton of surface coal and $0.30 per ton of underground coal.	7% of gross value with $0.60 per ton tax ceiling for surface production; 3.75% of gross value with $0.30 per ton tax ceiling for underground production.
Northwest			
Alaska[1]	Mining License Tax on Net Income	No tax if net income is $40,000 or less; $1,200 plus 3% of net income over $40,000; $1,500 plus 5% of net income over $50,000; and $4,000 plus 7% of net income over $100,000.	Assumes a single mining operation in the highest tax bracket with net

EXHIBIT 6-9. REPORTED COAL SEVERANCE TAX RATES BY STATE, 2012

STATE	SEVERANCE TAX TYPE	RATE	ASSUMED RATE
	Production Royalty on State Lands	NA	income greater than $100,000. Estimates taxes based on gross value over $100,000 rather than net income over $100,000.
Western Interior			
Arkansas[2]	Natural Resources Severance Tax	$0.02 per ton of coal, lignite and iron ore plus an additional $0.08 per ton on coal.	$0.1325 per ton
Kansas	Minerals Severance Tax	$1.00 per ton coal produced. Severance or production of the first 350,000 tons of coal at any mine is exempt from taxation.	Assumes all mining falls under small mine exemption, as no revenues were collected in 2009 or 2010.
Missouri	No Coal Severance Tax	-	
Oklahoma	No Coal Severance Tax	-	

Notes:
NA Not applicable
[1] Assumed tax rate for analysis is derived from reported tax rate.
[2] Assumed tax rate for analysis is derived by dividing 2012 coal severance tax revenues by 2012 coal production.
Sources: Alabama - §40-13-50, 40-13-61, Code of Alabama, 1975; Kentucky - KRS §143.020. KRS §143.010(13). KRS §143.010(14). KRS §143.021(3); Ohio - Ohio Revised Code (ORC) §5749.02(A)(1); ORC §5749.02(A)(8); ORC §5749.02(A)(9); Tennessee – Tennessee Code 67-7-104; West Virginia - West Virginia Code §11-13A; West Virginia Code §11-13V-4; Colorado – Quarterly Final Tax Rate for most recent reported quarter January 2010. Colorado Revised Statues Regulations 39-29-106; New Mexico - 2010 New Mexico Statutes Annotated 1978 7-26-6; "Taxation of Coal and Other Energy Resources." January 2009. New Mexico Taxation and Revenue Department; Louisiana - R.S. 47:633; Montana - Montana Code Annotated 15-35-103; North Dakota – North Dakota Century Code §57-61-01.1; Wyoming - Wyoming State Statutes §39-14-104; Alaska - Alaska Statute 43.65; Alaska Statute 38.05.212; Arkansas - Arkansas Code Annotated §26-58-101 et. seq.; Kansas – Kansas Statues Annotated Chapter 79: Taxation, Article 42: Mineral Severance Tax.

EXHIBIT 6-10. ESTIMATED COAL SEVERANCE TAX REVENUE CHANGES UNDER THE PROPOSED RULE, 2020-2040

REGION	NET PRESENT VALUE[1]	ANNUALIZED
Appalachian Basin		
Alabama	($77,000)	($7,100)
Kentucky[2]	($3,320,000)	($307,000)
Ohio	($138,000)	($12,800)
Tennessee	($23,300)	($2,150)
West Virginia	($15,100,000)	($1,400,000)
Regional Total:	($18,700,000)	($1,720,000)
Colorado Plateau		
Colorado	$8,720	$804
New Mexico	$95	$9
Regional Total:	$8,810	$813
Gulf Coast		
Louisiana	($3)	$0
Regional Total:	($3)	$0
Illinois Basin		
Kentucky[2]	($3,320,000)	($307,000)
Regional Total:	($3,320,000)	($307,000)
Northern Rocky Mountains and Great Plains		
Montana	($904,000)	($83,400)
North Dakota	$0	$0
Wyoming	($3,900,000)	($360,000)
Regional Total:	($4,810,000)	($444,000)
Northwest		
Alaska	$0	$0
Regional Total:	$0	$0
Western Interior		
Arkansas	$0	$0
Kansas	$0	$0
Regional Total:	$0	$0
TOTAL	**($26,800,000)**	**($2,470,000)**

[1] Calculated at a 7 percent discount rate.

Impacts are calculated as a difference from baseline projections, which represent existing regulatory requirements.

[2] Production in Kentucky is evenly divided between Appalachian Basin and Illinois Basin regions.

6.6 CAVEATS AND LIMITATIONS

An important limitation of our approach is that IMPLAN (and input-output models in general) provides a static set of results that do not account for technological shifts, price changes, sectoral growth, or other factors that could change behavior and affect the long-term impacts of a project. Other key limitations are presented below.

EXHIBIT 6-11. TREATMENT OF KEY UNCERTAINTIES IN THE REGULATORY IMPACT ANALYSIS

UNCERTAINTY	TREATMENT OF UNCERTAINTY
Compliance costs and changes in industry behavior that will be associated with this rulemaking are not known with certainty.	We developed a detailed description of each element of the rule, and conducted an engineering analysis of the expected impacts of the rule on mine operations.
Compliance costs and changes in industry behavior in response to the rule will vary by mine type and location, and according to site-specific conditions	Because the industry is heterogeneous, we forecast impacts at 13 model mines across the U.S. to provide a representational understanding of the changes actual mines may face. In doing so, the analysis provides an overall measure of the scope and scale of potential changes under each alternative, but is not likely to be accurate with regard to any specific mining operation. Specific to longwall operations, OSMRE is conducting an additional analysis of potential impacts, and has requested comment on this issue in the Proposed Rule.
Future coal demand is not known with certainty.	Three baseline coal demand scenarios are estimated. In addition to the most likely to occur scenario, "high coal demand" and "low coal demand" scenarios are conducted.
Future coal supply is not known with certainty.	The method for forecasting future coal production is detailed in Chapter 5 of this analysis. The resulting forecast is compared against other published coal forecasts (specifically, EIA).
Whether the Proposed Rule will result in permitting delays is unknown.	The analysis qualitatively discusses the potential for the Proposed Rule to result in additional permit delays. OSMRE has asked for public comment on this issue.
Future regulatory initiatives that could impact the industry are not known.	The analysis identifies existing and potential environmental regulations that are expected to influence mining practices / coal demand and legislative initiatives to reduce greenhouse gas emissions.
Administrative costs are estimated by OSMRE.	The agency is asking for comment on these costs in the rulemaking.

CHAPTER 7 | ENVIRONMENT & HUMAN HEALTH

The changes in mining practices prompted by the Proposed Rule will likely reduce adverse impacts on the environment and human health. These improvements in environmental conditions should, in turn, provide ecosystem service benefits, which are defined as the contributions that ecosystems make to people's well-being. As described in Chapter 4, the Proposed Rule requirements would also affect coal production costs, which in turn would change the volume of coal produced in each region as well as the mix of production methods (surface versus underground mining). These indirect changes can also influence environmental impacts of coal mining that vary with production levels, such as air pollutant emissions and the incidence of mining accidents. This chapter describes the analysis used to quantify environmental and human health impacts, and the results of this analysis.

7.1 INTRODUCTION AND SUMMARY OF RESULTS

Proposed Rule requirements related to the creation of riparian buffer zones, stream restoration, reforestation, and other practices are expected to reduce the adverse impacts of coal mining on water resources and aquatic habitat, and may also benefit terrestrial habitat, visual resources, and recreational activities. In addition, baseline data collection, defining material damage, and increased monitoring are expected to reduce the risk and severity of impacts by facilitating more prompt recognition of emerging pollution problems. This chapter draws on the model mine analysis to evaluate changes attributable to the Proposed Rule and the impact of those changes on environmental and health outcomes. Where feasible, the analysis quantifies changes in environmental and human health impacts, aggregating these changes by region. The analysis is developed on a per-ton production basis.

Exhibit 7-1 summarizes the categories of impacts that are expected to result from the Proposed Rule over the study period and presents them quantitatively where possible. The various categories of benefits discussed are interrelated in that multiple types of environmental improvements may lead to similar types of ecosystem service benefits. For example, both water and air quality benefits have the potential to reduce public health risks; similarly both improved water quality and increased forest land cover have the potential to generate aesthetic and recreational benefits.

EXHIBIT 7-1. SUMMARY OF TOTAL ENVIRONMENTAL AND HUMAN HEALTH IMPACTS OF THE PROPOSED RULE: 2020-2040

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	DESCRIPTION OF CHANGE	EFFECT ON ECOSYSTEM SERVICES
Water Quality	Fewer stream miles adversely impacted, improved water quality (e.g., pH, selenium, TDS) within watershed. Potential for beneficial impacts to groundwater quality and quantity	Stream restoration, fill construction and handling requirements, and reforestation requirements	Per year: 4 stream miles not filled; 29 stream miles restored; 1 downstream preserved stream mile; 292 downstream improved stream miles	Increased water quality enhances ecosystem, recreational, and some consumptive use services
Biological Resources	Reduced impacts to aquatic riparian and forest communities, including habitat enhancements for threatened and endangered species	Stream restoration, reforestation, and species protection requirements	Water quality benefits stated above; Annual estimates of 2,811 acres of forest improved and 20 acres of forest preserved	Increased quality or quantity of habitat enhances recreational opportunities and aesthetic conditions
Visual Resources	Improved aesthetics	AOC requirements and reforestation requirements	Water quality, forest, and biological resource benefits stated above	Improved aesthetics may improve property values and the quality of recreational opportunities
Air Quality	Additional carbon storage, changes in emissions (e.g., NO_X, SO_2, PM, CH_4) from changes in mining activity levels	Reforestation requirements and fill design changes affect carbon storage capacity; Indirect effects of decreased mining activity affect changes in emission levels	Increased reforestation (see Biological resources above) and associated increased carbon storage; Reduced emissions of air pollutants (including greenhouses gases) due to overall reduction in coal mining activity (e.g., methane emissions decrease by approximately 311 million cubic feet (MMcf) per year).	Increased carbon storage and reductions in emissions reduce human health risks and climate change-related risks
Public Health	Reduced exposure to contaminants in drinking water	Stream restoration and reforestation requirements	Water quality resource benefits as stated above	Reduced probability of adverse health effects, or incurring costs to mitigate those effects
Recreation	Potential for increased recreational opportunities, improved aesthetics	Elements directly affecting water quality and biological resources (e.g., stream restoration) as well as AOC requirements and post-mining land use	Water quality, forest, and biological resource benefits stated above	Increased quality or quantity of recreational fishing, hunting, wildlife viewing, or hiking opportunities
Other	Reduced risk and severity of adverse impacts, including long-term pollution discharges	Baseline data collection, monitoring, and material damage definition	Water and air quality resource benefits as stated above	Reduced human health risks, improved recreational opportunities, improved aesthetics

The Proposed Rule generates ecosystem service benefits in two ways. First, implementation of the rule requirements (e.g., reducing stream fill, requiring restoration and enhancement, reforestation and revegetation elements) improves water and habitat quality, as described in Exhibit 7-1. Improved environmental conditions in turn reduce human health risks from exposure to water or air-borne contaminants. They also improve the aesthetics of the landscape and habitat conditions for native species, enhancing recreational experiences (e.g., fishing, hunting, hiking, wildlife-viewing) and potentially benefitting property values.

Second, ecosystem service benefits result from the overall reduction in coal mining activity (surface and underground) expected to result from the Proposed Rule. The collective burden on coal mine operators of implementing all of the rule elements increases the cost of coal production, as described in the previous chapters. The increased costs of production due to the Proposed Rule result in a reduction in overall coal production levels. Reduced production accordingly results in a reduction in the negative environmental impacts of coal mining, for example by preserving some streams from coal mining effects. One category of ecosystem service benefits described in Exhibit 7-1 that is attributed specifically to the reduction in overall levels of coal production (as opposed to the implementation of a given rule requirement) is air quality improvements (e.g., reduced emissions).

Given available data, we are unable to reliably monetize the benefits of the Proposed Rule. For four categories we are, however, able to quantify the benefits in terms of biophysical changes (i.e., units of the resource, such as stream miles or acres of forest). Exhibit 7-2 describes the categories of quantified benefits (results are summarized in Exhibit 7-1) and the reason these quantified changes are not monetized. Importantly, the quantified metrics described in Exhibit 7-2 do not present a complete picture of the benefits expected to water quality, biological resources, and air quality. In addition to these quantifiable metrics, additional water quality benefits (including reduced contaminant levels, improved conditions to support biodiversity), biological resources (including increased quality or quantity of habitat for endangered species), and air quality benefits (including increased carbon sequestration potential and reduced emissions of other contaminants) are described qualitatively in this chapter.

EXHIBIT 7-2. QUANTIFIED BENEFIT CATEGORIES

CATEGORY	QUANTIFIED BENEFITS METRICS	RATIONALE FOR NOT MONETIZING THE QUANTIFIED BENEFIT
Water Quality	• **Stream miles not filled:** Streams not filled due to the SPR. • **Stream miles restored**: Mined through streams that are restored due the SPR. • **Downstream stream miles preserved**: Streams that do not experience water quality impacts due to reduced mining activity. • **Downstream water quality improvements (miles)**: Streams that experience water quality improvements with the SPR.	While the analysis is able to estimate the linear extent of stream miles expected to be improved by the rule, the specific improvement in particular water quality parameters, such as pH or selenium levels, is uncertain. Information on both the baseline contaminant levels and the expected change in these water quality parameters at given mine sites would be required to monetize the improvement. To accommodate these uncertainties, information on the geographic scope of the stream improvements are presented alongside a qualitative discussion of the environmental changes and associated ecosystem service benefits (i.e., public health and recreational experiences) expected.
Biological Resources	• **Improved Acres:** Land that will benefit from improved forest land cover either because: a) it would have been restored to grassland, pastureland or an alternative PMLU in the baseline; or b) it would have been reforested under the baseline but the SPR prescribes better practices to ensure healthier forest post-mining (i.e., Forestry Reclamation Approach (FRA)). • **Preserved Acres:** Forest area that is left uncut due to changes in coal mining activity.	Ecosystem services associated with additional forest cover include reduced risk of climate change-related damages (due to increased carbon sequestration potential of the landscape), increased quality and quantity of endangered species and other species habitat, and aesthetic improvements (these improvements may also improve conditions for recreational activities and increasing property values). While increased forest and vegetative land cover resulting from the rule may increase the carbon sequestration potential of the landscape, other effects of the rule may counteract these by increasing carbon emissions. For example, increased hours spent hauling materials during reclamation may increase transportation emissions. Limitations on monetizing the carbon sequestration benefits of forests are discussed in Section 7.3. With respect to potential property value and recreational benefits, monetization of these benefits would require information on the specific locations of the acres likely to be improved due to the rule, as well as information on the baseline values of residential properties and volume and value of recreational activities.

CATEGORY	QUANTIFIED BENEFITS METRICS	RATIONALE FOR NOT MONETIZING THE QUANTIFIED BENEFIT
Air Quality	• **Reduced methane (CH_4) emissions:** Reduced methane associated with overall reductions in coal mining activity levels (note: not a net effect of the SPR on emissions levels).	Estimates of changes to methane provide some perspective on how reductions in coal production due to the Proposed Rule may affect mining-related emissions. However, this is not a complete picture of the effect of the rule on emissions. As discussed in Section 7.3, the quantified reduction in methane emissions is not a net effect as it does not account for potential counteracting effects of the rule due, for example, to increased haulage or increased production of substitute sources of energy production. Accordingly, while this estimate provides some context, namely describing that effects of the rule on emissions are on the order of a fraction of a percent of emissions from coal mining, presenting this effect as a monetized benefit of the rule may be misleading.

For other categories of benefits, data limitations do not support quantifying the improvements even in biophysical terms. We accordingly describe the following benefits qualitatively; more detailed discussion is presented in Section 7.3.

- **Public Health:** Existing studies find negative health effects of mining-related contaminants in water and air in coal mining communities.[144] Although more research on human exposure and human health impacts is still needed to fully understand causal relationships, we believe it is reasonable to assume the proposed rule will yield public health-related benefits through expected improvements in air and water quality.

- **Visual Resources:** Improved aesthetic conditions of the landscape post-mining has the potential to enhance recreational experiences (as noted above), as well as regional property values.

- **Recreational Benefits:** Potential benefits to fishing, hiking, wildlife-viewing, hunting, etc. due to improved quality of streams and increases forest land cover benefitting regional wildlife populations. In addition, aesthetic improvements due to reforestation and PMLU requirements may enhance recreational experiences.

7.2 OVERVIEW OF ANALYTIC METHODS FOR QUANTIFYING IMPACTS

This analysis draws upon the model mine analysis, additional spatial and economic data, and information from published literature to characterize impacts of the Proposed Rule. These impacts are quantified where possible and extrapolated to the mining region and over time based on production forecasts. Specifically, impacts are quantified according to the following steps:

[144] This literature is described in more detail in the Environmental Impact Statement that accompanies the Proposed Rule.

1. Elements of the Proposed Rule are inventoried and mapped to categories of environmental and health impacts;
2. Information on physical and operational changes at the mine level from the model mine analysis are combined with additional data and information to develop mine-level impact measures expressed per unit of production (where feasible);
3. Per-unit impacts are aggregated to the mining region and over the timeframe of the analysis based on production forecasts by region and by mine type (surface versus underground);

Policy studies frequently apply a “benefits transfer” approach in order to translate quantified impacts into monetary terms. Benefits transfer methods leverage research from existing studies to evaluate effects of a sufficiently similar policy or scenario. The method is formally recognized in the EPA’s *Guidelines for Preparing Economic Analyses* (2000, updated 2010) and the Office of Management and Budget’s *Guidance on Development of Regulatory Analysis*.[145]

EPA (2010) provides best-practice guidelines on the conduct of benefits transfer analyses. Specifically, the *Guidelines* describe the following steps:

1. **Describe the Policy Case** – This first step involves carefully describing the changes in environmental and/or health impacts to be valued.
2. **Select Study Cases –** This step involves identifying existing research or “study cases” that are applicable to the policy case. Specifically, study cases should be similar to the policy case in their definition of the environmental commodity to be valued, baseline and extent of change, and characteristics of affected populations.
3. **Transfer Values –** In this step, the values from the study case(s) are applied to the policy case, either via a unit-value (i.e., mean or median estimate) or benefits-function transfer.
4. **Report Results --** In this final step, results are presented and the uncertainty associated with the transfer quantified.

For example, improved water quality is an asset that provides flows of ecosystem services.[146] Numerous studies have estimated the benefits associated with improved water quality (e.g., Van Houtven, et al., 2007 provide a summary of this literature) and some studies have specifically estimated the value the public places on avoiding mining-related impacts. [147] For example, Van Houtven, et al. (2007) find that the average

[145] OMB. 2003. Circular A-4: Guidance on Development of Regulatory Analysis. Issued September 17, 2003.

[146] Freeman, A. 2003. *The Measurement of Environmental and Natural Resource Values*. Second ed., Resources for the Future; National Research Council of the National Academies. 2005. Valuing Ecosystem Services: Toward Better Environmental Decision-Making. National Academies Press.

[147] Van Houtven, G., Powers, J., and Pattanayak, S. 2007. Valuing Water Quality Improvements in the United States Using Meta-Analysis: Is the Glass Half-Full or Half-Empty for National Policy Analysis?. Resource and Energy Economics 29: 206-227; Whitehead, J. 1990. Measuring Willingness-to-Pay for Wetlands Preservation with the Contingent Valuation Method.

household willingness to pay for water quality improvements (or to avoid decrements) across 18 different studies is approximately $108 per year in 2011 dollars.[148] Whitehead (1990) estimates that Kentucky residents would be willing to pay between $10 and $22 per year to preserve 5,000 acres of wetland that may be impacted by coal mining.[149]

However, economic values are highly context-specific. The value of improved water quality is influenced by the magnitude of change in given water quality parameters, and existing and potential future uses of the water resources, which will vary spatially. For example, values will be influenced by whether the water resources support recreational uses, the nature and extent of species present, and proximity to population centers. It is not possible to predict the number, type, or location of specific mining operations over the time frame of the analysis. Similarly, it is not possible to predict or properly characterize affected resource attributes. Thus, assignment of monetary values to the changes expected to result from the Proposed Rule would be speculative. That is, it is not possible to accurately define the policy case and apply suitably similar values from existing literature. As a result, this RIA cannot satisfy EPA's requirements (1) and (2) above for a credible benefits transfer analysis.

The remaining sections of this chapter describe in detail the impact categories highlighted in Exhibit 7-1, providing quantitative impact measures in resource units (where feasible) and providing examples of related economic values.

7.3 METHODS AND ESTIMATED BENEFITS BY RESOURCE CATEGORY

WATER QUALITY

The Proposed Rule is expected to benefit surface water, wetland, and groundwater resources. For example, fill construction and handling requirements, restoration requirements, and reforestation requirements will reduce the number of stream miles filled, increase the number of stream miles restored, and generate general water quality improvements. In addition, increasing baseline data collection and analysis and monitoring during mining and reclamation may result in earlier detection of water quality problems, which should lead to more prompt resolution.

Surface Water

The approach for quantifying impacts of the Proposed Rule on surface water resources involves quantifying the linear extent of streams (measured in stream miles) affected within each region. The quantified factors include:

Wetlands 10(2): 187-201; Whitehead, J. and Blomquist, G. 1991. Measuring Contingent Values for Wetlands: Effects of Information About Related Environmental Goods. Water Resources Research 27(10): 2523-2531.

[148] Van Houtven, G., Powers, J., and Pattanayak, S. 2007. Valuing Water Quality Improvements in the United States Using Meta-Analysis: Is the Glass Half-Full or Half-Empty for National Policy Analysis?. Resource and Energy Economics 29: 206-227.

[149] Whitehead, J. 1990. Measuring Willingness-to-Pay for Wetlands Preservation with the Contingent Valuation Method. Wetlands 10(2): 187-201.

- Reduction in streams filled;
- Increased restoration of ephemeral streams that are mined through;
- Stream miles downstream of mine sites experiencing improved water quality; and
- Stream miles preserved from adverse effects of mining.

Exhibit 7-3 summarizes the steps involved for each of these quantified factors, and the text describes the methods in greater detail.

Methods for Estimating Reduction in Miles of Streams Filled and Increased Restoration of Ephemeral Streams

The methods to quantify the reduction in stream miles filled and in ephemeral stream miles restored extrapolate from the findings of the model mine analysis. The model mine analysis estimates how mines in each coal region will implement the Proposed Rule requirements, and how these practices will affect stream fill and stream restoration actions. To quantify the broader, national benefits, the analysis translates the reduction in streams filled and the increase in stream miles restored into an average change in impacts per ton of coal produced for the modeled "typical" mines in each region. Then the analysis applies this multiplier to the estimated production (tons of coal produced) in each region.

EXHIBIT 7-3. METHODS FOR QUANTIFICATION OF BENEFITS TO WATER RESOURCES

STEP	REDUCTIONS IN MILES OF STREAMS FILLED	ADDITIONAL MILES OF EPHEMERAL STREAMS RESTORED	STREAM MILES DOWNSTREAM OF MINE SITES EXPERIENCING IMPROVED WATER QUALITY	STREAM MILES DOWNSTREAM OF MINE SITES THAT ARE PRESERVED FROM ADVERSE EFFECTS OF MINING
1	Determine number of stream miles filled by region based on conditions at the "typical mine"	Determine number of ephemeral stream miles restored by region based on conditions at the "typical mine"	Based on scientific literature, determine how far downstream of a mine site negative effects of coal mining persist. Limited data require use of a national average rather than mine-specific figures.	Determine how far downstream of a mine site negative effects of coal mining persist, on average
2	Convert to impact per million tons of coal produced by region/mine type, i.e., divide "typical mine" miles of streams filled by total "typical mine" coal production	Convert to impact per million tons of coal produced by region/mine type, i.e., divide "typical mine" miles of ephemeral streams restored by total "typical mine" coal production	Analyze, by region and mine type (i.e., surface versus underground), the number of streams that flow off of a mine site, on average	Analyze, by region and mine type (i.e., surface versus underground), the number of streams that flow off of a mine site, on average
3	Multiply the figure on stream miles filled per million tons (Step 2) by total regional coal production in each year of analysis	Multiply the figure on stream miles restored per million tons (Step 2) by total regional coal production in each year of analysis	Multiply the number of streams crossing the mines (Step 2) by the average extent of downstream water quality effects (Step 1) to estimate the "typical mine" downstream miles affected	Multiply the number of streams crossing the mines (Step 2) by the average extent of downstream water quality effects (Step 1) to estimate the "typical mine" downstream miles affected
4	Sum miles of stream filled across the study period	Sum miles of ephemeral streams restored across the study period	Convert to impact per million tons of coal produced by region/mine type, i.e., divide "typical mine" downstream miles affected by total "typical mine" coal production	Convert to impact per million tons of coal produced by region/mine type, i.e., divide "typical mine" downstream miles affected by total "typical mine" coal production
5	Estimate average annual stream miles filled, i.e., divide total stream miles filled by years in study period	Estimate average annual ephemeral stream miles restored, i.e., divide total ephemeral stream miles	Multiply the downstream miles affected per million tons by the expected coal production for the relevant mine type/region for	Multiply the downstream miles affected per million tons by the expected coal production for the relevant mine type/region for

STEP	REDUCTIONS IN MILES OF STREAMS FILLED	ADDITIONAL MILES OF EPHEMERAL STREAMS RESTORED	STREAM MILES DOWNSTREAM OF MINE SITES EXPERIENCING IMPROVED WATER QUALITY	STREAM MILES DOWNSTREAM OF MINE SITES THAT ARE PRESERVED FROM ADVERSE EFFECTS OF MINING
		restored by years in study period	each year in the study period	each year in the study period
6	Estimate benefit by subtracting Proposed Rule annual average miles from annual average miles in baseline scenario	Estimate benefit by subtracting Proposed Rule annual average from baseline annual average	Sum downstream miles affected across the study period	Sum downstream miles affected across the study period
7			Estimate average annual downstream miles affected by dividing total downstream miles affected (Step 6) by years in study period	Estimate average annual downstream miles affected by dividing total downstream miles affected (Step 6) by years in study period
8			Total downstream miles improved is equal to the downstream miles affected (i.e., water quality in these streams is improved as compared to the baseline)	Estimate benefit of Proposed Rule by subtracting anticipated annual average miles from baseline annual average miles

Methods for Estimating Stream Miles Downstream of Mine Sites Experiencing Water Quality Improvements

The analysis uses the following method to estimate the number of improved stream miles downstream of mine sites. First, the analysis incorporates findings from the scientific literature to estimate how far downstream of a mine site negative effects of coal mining persist. The scientific literature addressing effects of coal mining on water resources primarily focuses on how coal mining affects stream water quality, as summarized in Exhibit 7-4.

The history and extent of mining in the Appalachian Region makes it the subject to the majority of the water quality studies.[150] In general, these studies describe coal mining's effects on stream quality, but do not specify the particular aspect of mine operations that generates the adverse effects. As such, the studies do not support an explicit analysis of individual elements included in the Proposed Rule or their impacts on downstream water quality.

While a review of the available literature identified many analyses of coal mining's impact on water quality, only one study identified the geographic extent of the adverse effects of mining on downstream water quality. Specifically, Petty, et al. (2010) estimate that the downstream effects of mining extend approximately 6.2 miles from the mine site. The Petty, et al. (2010) research includes stream sampling from both underground and surface mining and includes both pre- and post-SMCRA mining activities in the Appalachian coal region.[151] Although the Petty, et al. (2010) study represents the best available information with respect to the geographic scope of adverse water quality impacts of mining, the inclusion of pre-SMCRA mining activity in the stream sampling may lead to an overestimate of baseline impacts. Absent additional studies estimating the geographic extent of downstream effects from mining in other coal regions, this analysis applies findings from Appalachia to other regions. The extent of downstream effects may be influenced, however, by a variety of site-specific factors that may vary considerably across regions and even within regions, such as mine density, topography, and precipitation. Consequently, it is difficult to determine if this analysis over- or underestimates affected stream length in other regions or at any given mine site. Absent

[150] Lindberg, T., Bernhardt, E., Bier, R., Helton, A., Merola, B., Vengosh, A., and Di Giulio, R. 2011. Cumulative impacts of mountaintop mining on an Appalachian watershed. PNAS Early Edition. www.pnas.org/cgi/doi/10.1073/pnas.1112381108; Merriam, E.R., Petty, J.T., Merovich, G.T., Fulton, J.B. and Strager, M.P. 2011. Additive effects of mining and residential development on stream conditions in a central Appalachian watershed. Journal of North American Benthological Society 30(2): 399-418; Petty, T., Fulton, K., Strager, M., Merovich, G., Stiles, J., and Ziemkiewicz, P. 2010. Landscape indicators and thresholds of stream ecological impairment in an intensively mined Appalachian watershed. Journal of North American Benthological Society 29(4): 1292–1309; Pond, G., Passmore, M., Borsuk, F., Reynolds, L., and Rose, C. 2008. Downstream effects of mountaintop coal mining: comparing biological conditions using family-and genus-level macroinvertebrate bioassessment tools. Journal of North American Benthological Society 27(3): 717–737; Fulk, F., Autrey, B., Hutchens, J., Gerritsen, J., Burton, J., Cresswell, C., and Jessup, B. 2003. Ecological Assessment of Streams in the Coal Mining Region of West Virginia Using Data Collected by the U.S. EPA and Environmental Consulting Firms. U.S. Environmental Protection Agency, National Exposure Research Laboratory.

[151] Petty, T., Fulton, K., Strager, M., Merovich, G., Stiles, J., and Ziemkiewicz, P. 2010. Landscape indicators and thresholds of stream ecological impairment in an intensively mined Appalachian watershed. Journal of North American Benthological Society 29(4): 1292–1309

this site-specific information on the extent of downstream water quality effects of mines, this analysis assumes, on average, that adverse effects of mining on water quality persist 6.2 miles downstream of mines for streams that cross the disturbed area of a mine site.

EXHIBIT 7-4. SELECTED SCIENTIFIC LITERATURE REGARDING THE EFFECTS OF COAL MINING ON WATER QUALITY

STUDY AUTHORS AND TITLE	CONFERENCE/ PUBLICATION	STUDY LOCATION	STUDY SUBJECT
*Fulk, et al., 2003. Ecological assessment of streams in the coal mining region of West Virginia using data collected by the US EPA and environmental consulting firms	Mountaintop Mining/Valley Fills in Appalachia Final Programmatic Environmental Impact Statement	Five watersheds: Mud River, Spruce Fork, Clear Fork, Twentymile Creek, & Island Creek Watersheds	Analysis of water quality and biota metrics in watersheds rated as unmined, mined, filled, and filled/residential
Lindberg, et al., 2011. Cumulative impacts of mountaintop mining on an Appalachian watershed	Proceedings of the National Academy of Sciences Early Edition	Upper Mud River, Southwest West Virginia	Analysis of areal extent of mining in watersheds and use of physical water quality metrics, including conductivity, and concentrations of sulfate, selenium, and magnesium; assessed these metrics upstream and downstream of mine sites, as well as in reference streams
Merriam, et al., 2011. Additive effects of mining and residential development on stream conditions in a central Appalachian watershed	Journal of North American Benthological Society	Pigeon Creek watershed, Southern West Virginia	Analysis of mining intensity in a watershed and correlation with metrics of stream health, including EPT richness
Petty, et al., 2010. Landscape indicators and thresholds of stream ecological impairment in an intensively mined Appalachian watershed	Journal of North American Benthological Society	Lower Cheat River basin, Northern West Virginia	Analysis of mining intensity in a watershed and correlation with metrics of stream health, including EPT richness
Pond, et al., 2008. Downstream effects of mountaintop coal mining: comparing biological conditions using family- and genus-level macroinvertebrate bioassessment tools	Journal of North American Benthological Society	37 small West Virginia streams	Analysis of mining effects judged by specific conductance correlated with four measures of biological health, including Ephemeroptera richness, but not EPT richness
Note: An asterisk (*) denotes a study not published in the peer reviewed literature.			

In the second step, the analysis estimates the average number of streams that flow off of a mine site by region and mine type (i.e., surface versus underground). This step employs GIS data identifying locations of historical mines in each region by mine type.[152] As the

[152] National Mine Map Repository. Provided by OSMRE on June 5, 2013; U.S. Plants and Impoundments Point Shapefile. Provided by Morgan Worldwide Consultants, Inc. on July 26, 2013; Arkansas Department of Environmental Quality. Facility and Permit Summary. http://www.adeq.state.ar.us/home/pdssql/pds.aspx; Colorado Division of Reclamation Mining and Safety. 2010. GIS Data. Department of Natural Resources. http://mining.state.co.us/Reports/Pages/GISData.aspx; Illinois State Geological Survey. 2011. Coal Maps and Data. https://www.isgs.illinois.edu/research/coal/maps; Indiana Geological

GIS data are only points identifying locations of historical mines, the analysis estimates the size of each mine site relying on the size of the "disturbed area" for typical mines. After mapping the location and size of historical surface and underground mines in each region, the analysis references the U.S. Geological Survey's high resolution National Hydrography Dataset to estimate the average number of streams flowing off of surface and underground mines in each region.[153]

For these historical surface mines, between one and seven streams cross each mine site, and the average varies by region. An average of one stream flows through the surface portion of underground mines (consistent with the structure of coal preparation facilities at underground mines). Exhibit 7-5 presents the results of the GIS analysis quantifying number of streams crossing mine sites.

EXHIBIT 7-5. RESULTS OF GIS ANALYSIS OF STREAM CROSSINGS AT MINE SITES

REGION AND MINE TYPE	ESTIMATED NUMBER OF STREAMS CROSSING MINE SITE
Northern Appalachia Surface	1.3
Central Appalachia Surface	3.1
Colorado Plateau Surface[1]	3
Gulf Coast Surface	4.3
Illinois Basin Surface	3.4
Northern Rocky Mountains Surface	7.2
Western Interior Surface	3.3
Northwest Surface[2]	5
Underground Mines (All Regions)	1

[1] The Colorado Plateau surface mine figure is the average of the number of streams leaving the mine site from the one surface mine site in the GIS database for the Colorado Plateau and the Colorado Plateau surface mine site in the engineering analysis.
[2] The Northwest surface mine figure is the number of streams leaving the Northwest surface mine site in the engineering analysis as there are no sites that meet the criteria for the GIS analysis.

The third step of the analysis multiplies the average number of streams crossing the mines by the average spatial extent of downstream water quality effects (6.2 miles) to estimate the total number of downstream stream miles affected by coal mining for each region/mine type.

Note that the estimate of total downstream stream miles affected at a given mine implicitly assumes no downstream convergence. This assumption allows for a

Survey. Coal Mine Information System. http://igs.indiana.edu/CMIS/Downloads.cfm; and Railroad Commission of Texas, Surface Mining and Reclamation Division. 2011. Active Coal Mines. http://www.rrc.state.tx.us/about-us/organization-activities/divisions-of-the-rrc/surface-mining-reclamation-division/

[153] To estimate the average number of streams flowing off of the mine site, this analysis counts the number of times perennial and intermittent streams intersect the mine site and divides this by two. This method assumes that each stream crosses the mine site once upstream of the mine and once downstream of the mine. Ephemeral streams are not included in the calculations. The analysis uses USGS classifications to differentiate streams.

comparison across regions that reflects the stream density of different regions. However, it is likely that for some mines, streams crossing the mine sites ultimately converge. In such cases, the total number of stream miles experiencing improved water quality may be overestimated. On the other hand, the extent of the water quality improvement may be greater downstream of the convergence of two improved streams.

In the fourth step, the analysis divides the total downstream miles affected by coal mining activity by the estimated coal production at each "typical mine." This calculation yields an estimate of average miles of stream water quality affected per million tons of coal produced.

The next steps of the analysis yield an estimate of the total extent of water quality effects over the study period. The analysis multiplies the estimated per-million-ton downstream effects of the regional "typical mines" by the regional production forecast over the study period (Steps 5 and 6). Dividing the total miles of downstream water quality affected over the study period by the number of years of analysis (21) yields an average annual downstream water quality impact in miles (Step 7).

The analysis calculates these results for each region and mine type, for the baseline and Proposed Rule scenarios. As the Proposed Rule improves the management of mining operations to mitigate effects on water quality, the stream reaches downstream of the mine sites will experience some amount of improvement in water quality as compared to the baseline. While data are not available to determine whether the Proposed Rule will reduce the number of downstream miles adversely affected by mining, implementing the rule will at least reduce the level of adverse effect within the 6.2-mile downstream areas. Improvement in water quality does not mean that an impaired stream is completely restored; rather, improvement is considered an incremental betterment of water quality.

As an example, results for the Appalachian Surface Contour Mine for Proposed Rule are presented in Exhibit 7-6. Improved miles for other mines and regions are calculated in the same manner.

EXHIBIT 7-6. CALCULATIONS FOR DOWNSTREAM IMPROVED STREAM MILES FOR THE CENTRAL APPALACHIAN SURFACE CONTOUR MINE, PROPOSED RULE

STEP	CATEGORY	INPUTS	RESULTS
1	Average Number of Streams that Flow Off of Model Mine Site	See table above	Average of 3.1 streams flowing off of the mine site.
2	Per Million Ton Estimate of Downstream Improved Stream Miles	3.1 Streams * 6.2 Miles / 5 Million Tons	3.8 stream miles per million tons
3	Annual Regional Downstream Improved Stream Miles	3.8 stream miles per million tons * 523 million tons mined in the study period / 21 years in study period	94 downstream improved stream miles per year in study period

Stream Miles Downstream of Mine Sites Preserved from Adverse Effects of Mining

This analysis also estimates the downstream miles for which adverse effects from mining activities are expected to be avoided due to the Proposed Rule. The difference between the length of downstream affected stream miles in the baseline minus miles estimated under the Proposed Rule represents miles preserved. The baseline calculation follows the same steps as the Proposed Rule calculation, except the results are for stream miles affected, not steam miles improved. In cases where production increases for a particular region and mine type, the downstream stream miles preserved can be negative, reflecting an increase in downstream stream miles affected by mining. Aggregated across mine types, however, no net increase in downstream miles occurs.

Results of the Quantitative Analysis of Surface Water Impacts

As shown in Exhibits 7-7 and 7-8, the Proposed Rule is estimated to yield downstream improvements in 292 miles of stream annually. Downstream miles preserved are estimated to be about one mile per year, while four miles would not be filled each year and 29 miles would be restored each year. The following conclusions can be drawn from these results:

- **Reductions in streams filled:** The quantified reduction in the miles of filled streams varies across regions. The Appalachian Basin is the only region where excess spoil fills are common, making it the only region where a change in stream filling practices is anticipated.[154] Reduced fill benefits of the Proposed Rule on surface mining are accordingly limited to this region.
- **Increase in ephemeral stream restoration:** As more ephemeral streams occur in the Colorado Plateau, Gulf Coast, Illinois Basin, and Northern Rocky Mountains Regions, the benefits of ephemeral stream restoration requirements are concentrated in these regions.
- **Downstream miles experiencing improved water quality:** The majority of improved stream miles are expected to occur in Appalachia, as small mine size and high stream density leads to high per-ton impacts of changes to mining practices on downstream stream miles affected by mining. Rule elements related to monitoring and the definition of material damage to the hydrologic balance may improve water quality at surface mine sites, as would changes in mine site practices related to stream restoration and fills. The engineering analysis found that direct stream impacts from underground mines were temporary; therefore, downstream improved miles from underground mines are not quantified.
- **Downstream miles preserved:** The length of incremental downstream miles preserved due to the Proposed Rule is related to the expected changes in coal production relative to baseline production. The vast majority of preserved stream miles occur in Appalachia, the region anticipated to experience the greatest reduction in surface coal mining activity under the Proposed Rule.

[154] Illinois Basin ephemeral streams are sometimes used in the construction of sediment basins or slurry impoundments.

EXHIBIT 7-7. AVERAGE ANNUAL STREAM MILE IMPACTS BY REGION UNDER THE PROPOSED RULE: 2020-2040

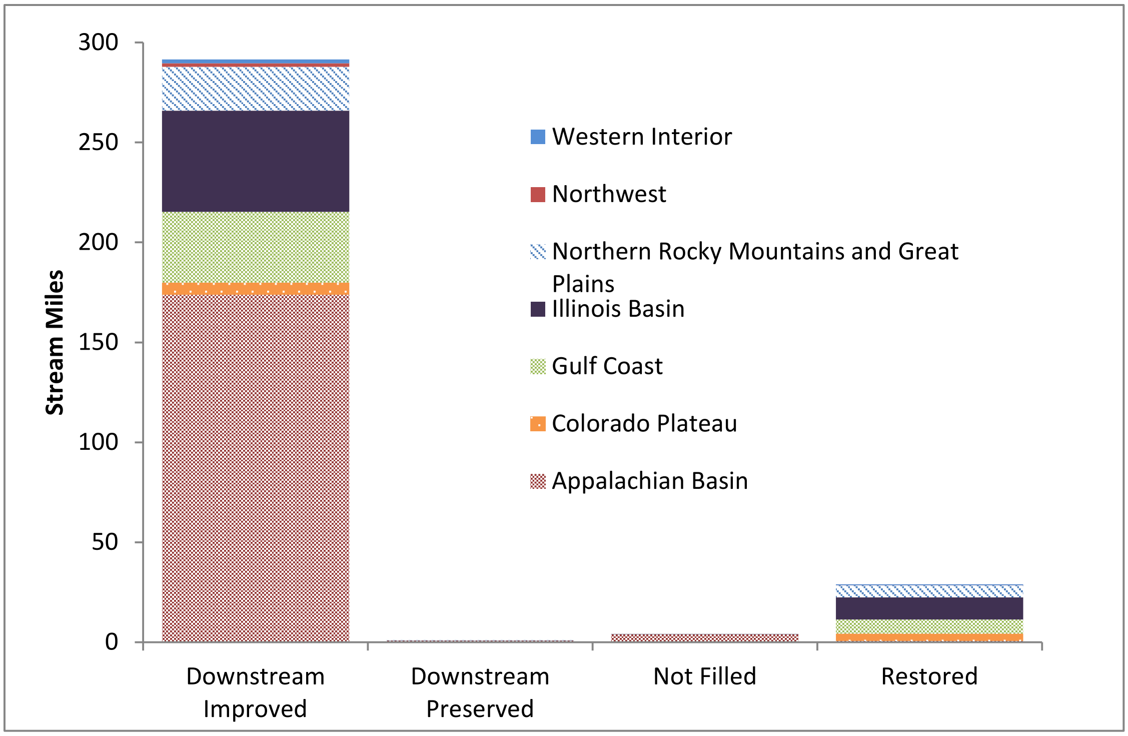


EXHIBIT 7-8. AVERAGE ANNUAL STREAM MILE IMPACTS UNDER THE PROPOSED RULE BY REGION: 2020-2040

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	174	1	4	1
Colorado Plateau	6	0	0	4
Gulf Coast	36	0	0	7
Illinois Basin	51	0	0	11
Northern Rocky Mountains and Great Plains	22	0	0	6
Northwest	2	0	0	0
Western Interior	2	0	0	0
Total	**292**	**1**	**4**	**29**

1 Stream miles that experience water quality improvements with the Proposed Rule.
2 Stream miles that do not experience water quality impacts due to reduced mining activity.
3 Streams not filled due to the Proposed Rule.
4 Mined through streams that are restored due to the Proposed Rule.

Information that describes impacts on streams from coal mining under the baseline for the analysis provide some context for understanding Proposed Rule impacts. While comprehensive and parallel measures of current coal mining impacts on streams are not generally available, the following studies and analytic observations have addressed some aspects of these impacts:

- **Stream fills.** With respect to understanding the number of stream miles not filled due to the Proposed Rule, five other studies provide some context, estimating historical stream fills in Appalachia at between 18 and 110 miles per year, depending on the time frame and study area:
  - Shank (2010) and Shank and Gebrelibanos (2013) used GIS analysis to compile data on refuse fill in West Virginia between 1984 and 2012, and estimated linear stream loss due to fill construction over time.[155] The more recent study estimates that 766 miles of perennial and intermittent streams were filled during the study period (1984 to 2012, which equates to an average of 28 miles per year). The study also documents a marked decrease in fill construction starting in approximately 2003. In 2012, stream miles filled decreased to approximately 18 miles in West Virginia for that year.[156]
  - The 2005 Mountaintop Mining EIS included two studies that estimate the effect of mountaintop mining and valley fills in West Virginia, Kentucky, Tennessee, and Virginia.[157]
    - The first study estimated that between 1985 and 2001, 724 stream miles (1.2 percent of streams) were covered by valley fills (equating to 45 miles filled per year). This study, known as the fill inventory, includes a variety of information regarding valley fills constructed from 1985 to 2001, including the feet of stream under valley fill footprints. This study measured streams based on a synthetic stream network defined on a 30-acre watershed accumulation threshold over the National Elevation Dataset (NED). The NED for each state was processed to enforce hydrologic integrity. A flow accumulation grid was prepared and queried to define a drainage network over the

[155] Shank, M. 2010. Trends in Mining Fills and Associated Stream Loss in West Virginia 1984-2009. West Virginia Department of Environmental Protection; Shank, M. and Gebrelibanos, Y. 2013. Trends in Mining Fills and Associated Stream Loss in West Virginia 1984-2012. West Virginia Department of Environmental Protection. http://tagis.dep.wv.gov/tagis/projects/Mining_Fill_trends_in_West_Virginia_1984-2012.pdf

[156] Shank, M. and Gebrelibanos, Y. 2013. Trends in Mining Fills and Associated Stream Loss in West Virginia 1984-2012. West Virginia Department of Environmental Protection. http://tagis.dep.wv.gov/tagis/projects/Mining_Fill_trends_in_West_Virginia_1984-2012.pdf

[157] U.S. EPA. 2005. Mountaintop Mining/Valley Fills in Appalachia Final Programmatic Environmental Impact Statement. Philadelphia, PA. EPA 9-03-R-05002. http://nepis.epa.gov/Exe/ZyPDF.cgi/20005XA6.PDF?Dockey=20005XA6.PDF

entire region. The synthetic stream network represents all drainage for watersheds greater than 30 acres.[158]

  - The 2005 Mountaintop Mining EIS also included a study that estimated impacts of mountaintop mining and valley fills between 1992 and 2002 of 1,200 stream miles (equating to approximately 110 miles per year), out of 58,998 streams in the study area. As with the previous study, this study also used GIS modeling of "synthetic streams" (in that they were not generated from existing maps, but instead were created by assuming that 30-acre areas generate a stream) to estimate potential impacts. This estimate of filled or mined through streams represents 2.05 percent of the stream miles in the study area.[159]

- In a 1998 study, U.S. FWS evaluated stream miles permitted or filled with excess spoil and other coal mining wastes in Kentucky, Pennsylvania, Virginia, and West Virginia between 1986 and 1998. This study found that at least 900 stream miles were permitted for filling in this time period (about 75 stream miles per year). The study did not evaluate actual stream miles filled, which are believed to be less than the number of miles permitted to be filled. Other uncertainties relating to the accuracy of this estimate are presented in study. Most notably, the study evaluated fills only for streams marked by USGS topographic maps as blueline streams.[160]

- **Mined through streams (restored)**. Few studies characterize the extent to which streams, and particularly ephemeral streams, are mined through. Inputs used in the model mines analysis provide partial context to the estimated incremental impacts. For instance, a typical surface mine in the Illinois Basin is estimated to mine through nine miles of ephemeral stream. Likewise, a surface mine in the Northern Rocky Mountain region is estimated to mine through nearly 35 miles of ephemeral stream. Given that these figures apply to individual model mines, the incremental restoration of ephemeral streams estimated in the analysis is likely to be minor compared to baseline levels of ephemeral streams mined through.

- **Streams degraded downstream of mining operations**. It is especially difficult to provide context to estimates of miles where water quality is improved given the general nature of this indicator. The second 2005 Mountaintop Mining EIS (EPA, 2005) study estimated 50 miles of direct stream impact per mineral extraction area; 156 miles per valley fill, and 307 miles per permit area. The study states that these may be overestimates. Existing data suggest that the

[158] Ibid.

[159] Ibid.

[160] U.S. FWS (United States Fish and Wildlife Service). 1998. Permitted Stram Losses Due to Valley Filling in Kentucky, Pennsylvania, Virginia, and West Virginia: A Partial Inventory. Pennsylvania Ecological Services Field Office, State College, PA.

incremental downstream miles improved by the Proposed Rule represent a relatively small share of the overall water resources in affected regions. For instance, while the Proposed Rule could contribute to water quality improvements in roughly 174 stream miles in the Appalachian Basin, this can be compared to approximately 126,000 total stream miles in the region. A more focused point of comparison would be to examine the total stream miles degraded by coal mining activities.

Groundwater

Mining impacts on groundwater resources vary depending upon method, overburden depth, and mined seam overburden stratigraphy and structure.[161] Some studies have shown that groundwater impacts are likely to occur within 1,000 feet of a surface mine (USGS, 2006) and within 1,400 feet of an underground mine (Booth, 1986).[162] Common impacts include the following:

- Water quality changes (i.e., increased levels of sulfate, hardness, total dissolved iron, manganese, and aluminum may occur as a result of runoff and infiltration.[163]
- Water levels may decline in nearby wells, either as a result of altered hydrology or as a result direct use of groundwater in mining operations.[164]
- Decreased streamflow may occur as a result of altered hydrology and reduced groundwater recharge of surface water.[165]

Rule elements, such as improved monitoring, reforestation, material damage to the hydrologic balance definition, and excess spoil material handling requirements under the Proposed Rule have the potential to reduce impacts to groundwater resources.

Insufficient information exists to characterize the likelihood and severity of groundwater impacts under the baseline and Proposed Rule scenarios. Further, the economic and health consequences associated with these impacts depend on their nature and location with respect to current or future drinking water supplies, which is also poorly characterized by available data.

[161] Kendorski, F.S. 1993. Effect of High-Extraction Coal Mining on Surface and Ground Waters. In: 12th Conference on Ground Control Mining. Morgantown, WV, August 3-5, 1993. U.S. Bureau of Mines.

[162] USGS. 2006. Ground-Water Quality in Unmined Areas and Near Reclaimed Surface Coal Mines in the Northern and Central Appalachian Coal Regions, Pennsylvania and West Virginia. National Water-Quality Assessment Program. Scientific Investigations Report 2006-5059; Booth, C. 1986. Strata movement concepts and the hydrogeologic impact of underground coal mining. Groundwater 24(4).

[163] USGS. 2006. Ground-Water Quality in Unmined Areas and Near Reclaimed Surface Coal Mines in the Northern and Central Appalachian Coal Regions, Pennsylvania and West Virginia. National Water-Quality Assessment Program. Scientific Investigations Report 2006-5059.

[164] Stoner, J.D. 1983. Probably Hydrologic Effects of Subsurface Mining. Ground water Monitoring Review 3(1): 128-137.

[165] Ibid.

BIOLOGICAL RESOURCES

Water quality improvements associated with the Proposed Rule will directly benefit biological resources. In addition, reforestation and habitat protection and enhancement requirements will also benefit biological resources, particularly terrestrial vegetation and fish and wildlife, and potentially threatened and endangered species. While it is not possible to quantify expected specific changes in species composition and abundance due to the rule, this analysis (in conjunction with the stream miles analysis in the preceding section) quantifies the acreage of forest that will be preserved due to the Proposed Rule, as well as the acreage expected to be "improved" due to the Proposed Rule as an indicator of biological resource benefits. These metrics and the methods for calculating them are briefly described below. A more detailed discussion of this analysis is provided in the Environmental Impact Statement prepared for the Proposed Rule and its Alternatives.

The improved forest acres metric quantifies the amount of land that would benefit from improved postmining forest land cover due to the Proposed Rule, either because: (a) rather than forestland, the land would have been restored to grassland, pastureland or an alternative postmining land use under the baseline; or (b) the land would have been reforested under the baseline, but would not have utilized practices that promote expeditious growth of healthier forest (e.g., Forestry Reclamation Approach (FRA)) that would be encouraged under the Proposed Rule. This analysis quantifies the volume of expected "improved" forest acres according to the following methodology:

> *Step 1: Estimate the acres of forest cut per million tons of coal produced at surface and underground mines in each region and under each Alternative.* This first step uses the estimated "disturbed area" per mine, the total volume of coal produced per mine, and an estimated premining forest land cover at mined sites (estimated using a GIS analysis described in the EIS).
>
> *Step 2: Establish expected reforestation practices under the baseline*. Reforestation of mine sites is already being practiced in some regions. Based on recent experience, OSMRE estimates that approximately 70 percent of all mining permits are being reclaimed to forestland across the Appalachian Region.[166] According to OSMRE's postmining land use data for 2007 through 2010, reforestation is occurring to a lesser extent in the Gulf Coast (approximately four percent of reclaimed acreage) and the Illinois Basin (approximately 11 percent). All other regions are implementing reforestation at negligible rates.[167]
>
> *Step 3: Determine expected reforestation levels under the Proposed Rule*. The Proposed Rule requires that reforestation be implemented according to improved

[166] Information provided by OSMRE forestry staff to IEc on July 26, 2013.

[167] Information on reforestation rates for all coal regions except Appalachia is derived from OSMRE data on postmining land use (PMLU) by state and region for 2007 through 2010; these data are compiled from OSMRE's Annual Oversight Reports. Note that the PMLU figures are not directly equivalent to reforestation rates. Specifically, while the reforestation rate is the percent of premining forest land that is reforested, the PMLU forestry rate is the percent of all mined land on which forests are planted. The PMLU forestry rate will be less than the true reforestation rate to the extent that forest land is returned to another use (e.g., agriculture). The PMLU rates are presented to acknowledge that mine operators in some regions appear to implement modest reforestation efforts as part of postmining land use programs.

reforestation practices. In addition to specifying reforestation practices, the Proposed Rule also requires that all previously forested acres and lands that would revert to forest under conditions of natural succession be reforested. The Proposed Rule includes an exception for prime farmland. Absent specific information on the share of previously forested area that would be eligible for exception, this analysis conservatively assumes that 70 percent of the previously forested acres would be forested in each region under the Proposed Rule. This assumption likely leads to an understatement of potential benefits in terms of improved forest acres, as less than 30 percent of the mine sites may be eligible for exceptions to reforestation requirements.

Step 4: Calculate number of reforested acres according to improved reforestation practices under the baseline from 2020 to 2040. Use the estimates of future coal production under the baseline and the rate of forest cut and reforested under the baseline to calculated expected reforestation under the baseline.

Step 5: Calculate number of reforested acres according to improved reforestation practices under the Proposed Rule from 2020 to 2040. Use the estimates of future coal production under the Proposed Rule and the rate of forest cut and reforested to calculated expected reforestation under the Proposed Rule.

Step 6: Calculate total and average annual forest acres improved. Subtract the baseline reforestation estimates from the Proposed Rule Reforestation estimates. To estimate average annual acres improved in each region, divide the total improved acres (2020-2040) by the 21-year timeframe of the analysis.

Preserved forest areas are forest areas that are expected to be left undisturbed by mining due to the Proposed Rule.[168] This is anticipated to occur when mining activity is reduced for other reasons due to the rule. This analysis quantifies the volume of these "preserved" forest acres according to the following methodology:

Step 1: Estimate the acres of forest cut per million tons of coal produced at surface and underground mines under the baseline and proposed rule. This is the same calculation as conducted for "improved" acres.

Step 2: Calculate forest acres cut under the baseline in each region across the timeframe of the analysis. Use the estimates of future coal production and the rate of forest cut per million tons under the baseline to calculate expected total forest cut under the baseline.

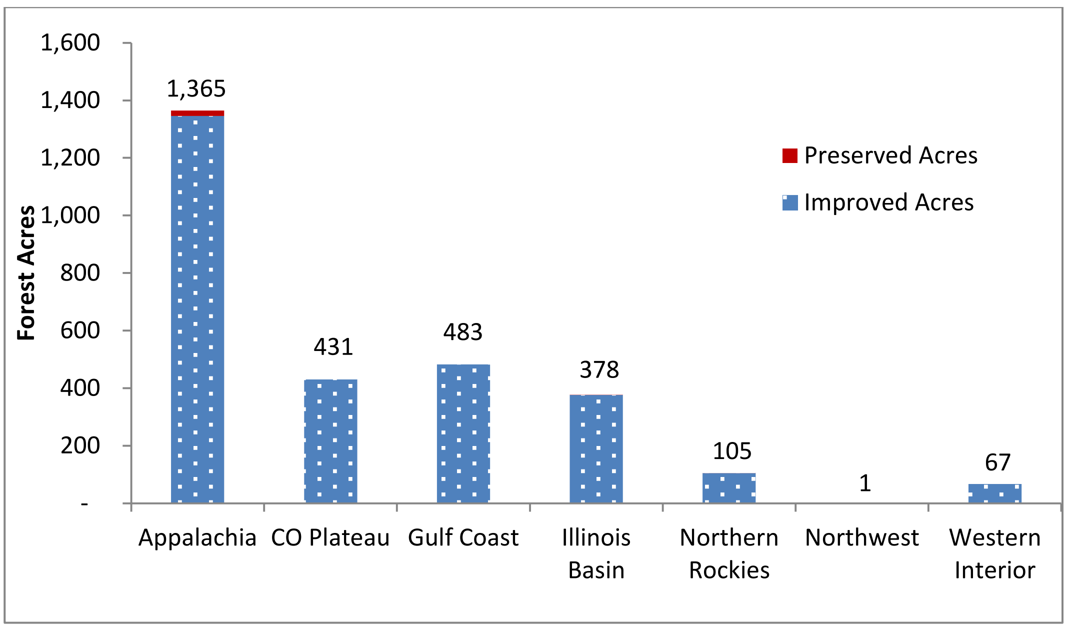
Step 3: Calculate forest acres cut under the Proposed Rule in each region across the timeframe of the analysis. Use the estimates of future coal production and the rate of forest cut per million tons under the Proposed Rule to calculate expected total forest cut under the Proposed Rule.

[168] In this analysis, "preserved" forest acres are those areas not cleared for mining during the study period. The forests are not preserved in perpetuity, i.e., they may be cleared for other purposes at some point in the more distant future.

Step 4: Calculate total and average annual forest acres preserved due to implementation of the Proposed Rule. Subtract the total forest acres cut under the Proposed Rule (2020-2040) from the total forest acres cut under the baseline. The difference reflects forest acres preserved (not cut) due to implementation of the Proposed Rule. Divide the total number of preserved acres by the 21-year timeframe of the analysis to estimate average annual forest acres preserved by region.

Exhibit 7-9 presents for each region the average annual forest acres that will be improved as a direct requirement of the Proposed Rule, as well as acres that will remain undisturbed (be preserved) due to the indirect effect of changes in coal production. The national average annual estimated forest acres improved over the time frame of the analysis is 2,811. The national average annual estimated forest acres preserved (left undisturbed) over the time frame of the analysis is 20 acres.

EXHIBIT 7-9. AVERAGE ANNUAL FOREST ACRES IMPROVED AND PRESERVED UNDER THE PROPOSED RULE: 2020-2040

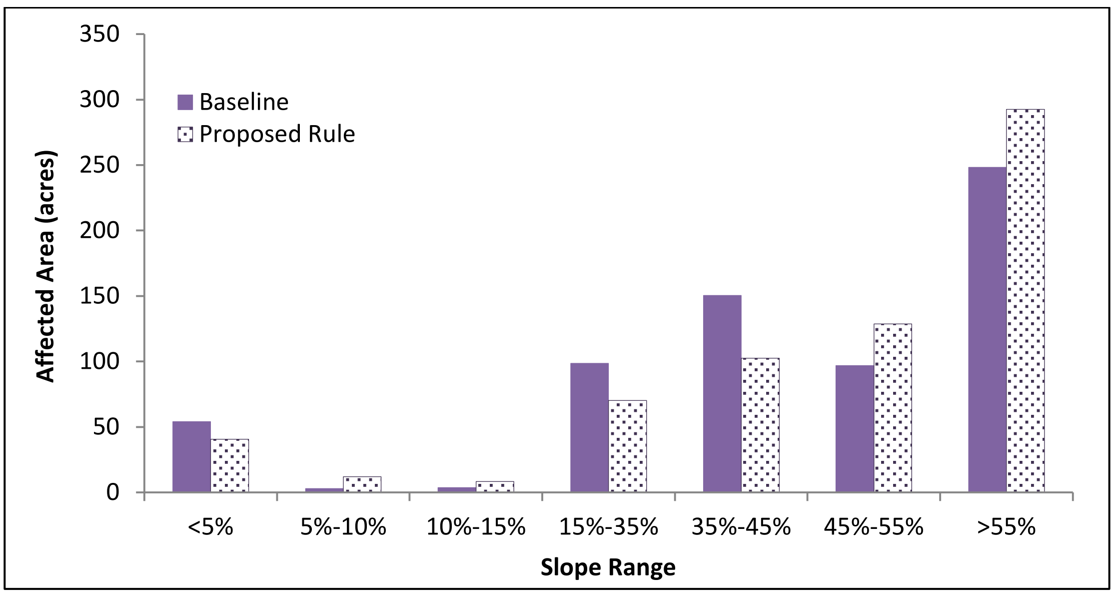


VISUAL RESOURCES

AOC and reforestation requirements will result in a post-mining landscape that more closely resembles pre-mining conditions. For example, Exhibit 7-10 below describes the distribution of post- versus pre-mining area by slope range, based on the model central Appalachia contour mine. Specifically, the graphs show the post-mining slope distribution that would exist under baseline requirements, and compare these to the slope distribution under the Proposed Rule. Comparison of the Baseline and Proposed Rule charts indicates that there are generally smaller deviations from pre-mining slopes under the Proposed Rule, particularly in the steepest slope categories. Analysis suggests that adherence to pre-mining slopes also would increase for non-contour surface mines in the Appalachian Basin, although the benefits are somewhat less pronounced. Changes in pre- and post-mining slope distribution in other regions are expected to be negligible, primarily because steep-slope pre-mining conditions are not as prevalent as in the Appalachian Basin.

As noted in the biological resources section, the Proposed Rule will also result in the reestablishment (or avoidance) of approximately 2,811 acres of forest annually. AOC and reforestation requirements will likely reduce impacts to visual resources, improving aesthetics and enhancing recreational opportunities (as discussed in the recreation section). In addition, to the extent that mining areas are visible from residential areas, it is likely that the Proposed Rule will reduce impacts associated with diminished views that may reduce property values. Several studies have demonstrated that the extent and nature of views from residential properties directly affect their value.[169] For example, Benson, et al. (1998) find that unobstructed mountain views increase property values by eight to nine percent, on average, in northwestern Washington State.[170]

EXHIBIT 7-10. ANALYSIS OF SLOPE CHANGE FOR CENTRAL APPALACHIA CONTOUR MINE



[169] Benson, E., Hansen, J., Schwartz, A., and Smersh, G. 1998. Pricing Residential Amenities: The Value of a View. Journal of Real Estate Economics and Finance (16): 55-73; Paterson, R. and Boyle, K. 2002. Out of Sight, Out of Mind? Using GIS to Incorporate Visibility in Hedonic Property Value Models. Land Economics 78(3): 417-25; Sander, H. and Polasky, S. 1983. The Value of Views and Open Space: Estimates from a Hedonic Pricing Model for Ramsey County, Minnesota, USA. Land Use Policy 26: 837-845.

[170] Benson, E., Hansen, J., Schwartz, A., and Smersh, G. 1998. Pricing Residential Amenities: The Value of a View. Journal of Real Estate Economics and Finance (16): 55-73.

AIR QUALITY

Through changes in mining practices and the indirect effects of changes in surface versus underground mine production, the Proposed Rule may affect emissions of particulate matter (PM), NO_X, SO_2, methane, and other air pollutants. Section 4.2.4 of the Proposed Rule EIS provides a detailed discussion connecting the individual rule elements to implications on air quality. Quantifying changes in most types of emissions, however, is complicated by the absence of data on coal mining-related emissions (e.g., for SO_2, PM-10, CO_2, and NO_X). Absent understanding of even baseline emissions levels of these pollutants from coal mine sites, quantifying the expected change in emissions due to the Proposed Rule is not feasible. We expect, however, that to the extent that the Proposed Rule reduces overall coal production, there will occur a commensurate reduction in air pollutant emissions from a given site. As noted elsewhere in this analysis, the overall changes in coal production are expected to amount to less than 0.2 percent of national coal production, and air quality improvements are not a specific target of any of the rule elements. Thus, we do not expect air quality changes to be a key benefit of this rulemaking. Some data are available, however, describing methane (CH_4) emissions generated by surface and underground coal mining activities and CO_2 emissions associated with coal combustion. While the CH_4 emissions data do not detail the particular coal mining practices that lead an operation to generate more or less methane emissions, the gross emissions data allow this analysis to provide some sense of how methane emissions may be affected by changes in overall levels of surface and underground coal production. Importantly, this information does not represent a *net* effect of the Proposed Rule on methane emissions but highlights one aspect of the effect of the rule on greenhouse gas emissions. Similarly, data exist describing CO_2 emissions associated with coal combustion. Although the rule elements do not directly regulate coal combustion, the collective effects of the rule on the costs of coal mining is expected to marginally reduce coal production levels and have a consequent benefit in terms of a reduction in CO_2 emissions from coal combustion. Here again, this does not reflect a total net effect of the Proposed Rule on CO_2 emissions.

Multiple technological and economic factors complicate a reliable accounting of the net effects of the Proposed Rule and Alternatives on pollutant and greenhouse gas emissions from mining and fuel combustion:

- Data are not available to quantify the magnitude or direction (positive or negative) of all emissions-related changes at a given mine site. For all types of air pollutant emissions, rule elements may generate counteracting effects (e.g., while reductions in production may decrease emissions, increased hauling and other vehicle and equipment use may increase them).

- If less coal is mined, the price of coal could increase and coal-fired plants could respond by substituting other fuels for coal, with a potential decrease in combustion-related emissions. However, combustion of substitute fuels produces a different mix of pollutants compared to coal combustion. For example, while natural gas combustion generally releases lower amounts of carbon dioxide and nitrogen oxides relative to coal, it releases greater amounts of methane, also a greenhouse gas. [171]

- While some power plants have the flexibility to switch to other fuels (e.g., natural gas) readily, other plants would require significant capital investment. The cost effectiveness of such investments is complex and plant-specific.

- The analysis is particularly complicated at a regional level. The distribution of mined coal to power plants is not straight forward, and may cross mining regions. Thus, predicting where emissions reductions would occur and estimating the ultimate effect on ambient air quality is analytically challenging.

- Uncertainty exists with respect to the baseline regulation of emissions at the individual power plant level;

For these reasons, the reduced coal mining-related emissions resulting from decreased coal production are difficult to predict with reasonable confidence. We expect, however, that due to the overall effect of the Proposed Rule in reducing coal mining, there is likely an overall benefit in terms of reducing pollutant and greenhouse gas emissions, though by what specific magnitude is uncertain.

Effects on Methane Emissions Generated by Coal Production

While these information limitations prevent a complete accounting of the net effect of the Proposed Rule on all air quality parameters, this section evaluates one key emissions effect of the rule: the expected impact on methane emissions at coal mine sites. In 2013, the EPA's Greenhouse Gas Reporting Program estimated that reporting mines produced 41.3 million tons of carbon dioxide equivalents (MMtCO2e) of methane, compared to 0.2 MMtCO2e of carbon dioxide and less than 0.05 MMtCO2e of nitrous oxide.[172]

EPA reports coal mining-related methane emissions data at the national level in its annual Greenhouse Gas Inventory report. For underground coal mining, MSHA monitors methane emissions from ventilation systems and EPA reports these data at the national level.[173] For surface coal mining, EPA estimates emissions as a multiple of the in-situ methane content of the coal that is mined. EPA (2011) provides estimates of this surface in-situ methane content for six of the seven basins considered in this analysis.[174] For the seventh basin, Gulf Coast, this analysis relies upon the national data provided in the EPA report.

[171] U.S. EPA. 2014d. Clean Energy: Natural Gas. http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html

[172] U.S. EPA. 2014e. Greenhouse Gas Reporting Program. GHGRP 2013: Reported Data – Underground Coal Mines. Accessed March 11, 2015 at: http://www.epa.gov/ghgreporting/ghgdata/reported/coalmines.html

[173] U.S. EPA. 2011b. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. EPA 430-4-11-005. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2011-Complete_Report.pdf

[174] Ibid.

These emissions estimates are translated to per-ton measures and aggregated by region and over the time frame of the analysis based on production forecasts. Exhibit 7-10 displays the average annual change in emissions over the time frame of the analysis by region and mine type. As shown, reductions in coal production due to the Proposed Rule may decrease annual methane emissions from coal mines by approximately 311 MMcf.

EXHIBIT 7-11. AVERAGE ANNUAL CHANGES IN METHANE EMISSIONS, PROPOSED RULE VS. BASELINE: 2020-2040 (MMCF)

REGION	SURFACE MINES	UNDERGROUND MINES	NET CHANGE
Appalachian Basin	(18)	(191)	(208)
Colorado Plateau	0	1	1
Gulf Coast	0	0	0
Illinois Basin	(4)	(80)	(84)
Northern Rocky Mountains & Great Plains	(18)	(1)	(19)
Northwest	0	0	0
Western Interior	0	0	0
TOTAL	**(39)**	**(271)**	**(311)**

The changes presented in Exhibit 7-11 constitute less than 0.2 percent of baseline coal mining methane emissions. We expect this relatively minor effect is indicative of the potential magnitude of effect of the Proposed Rule on other types of air pollutant emissions. This supports our statement above that air quality improvements are not expected to be a key benefit of the rulemaking. The public health and social cost of carbon implications of potential changes in air quality and greenhouse gas emissions are described in the following sections.

PUBLIC HEALTH

Changes in coal production associated with the Proposed Rule (0.2 percent decline from projected baseline production) reduces the overall levels of surface and underground production, generating coincident benefits to water and air quality, as described previously. People may be exposed to coal mining-related contaminants through several different exposure pathways. For example, after they have been mobilized into air, surface water or groundwater, contaminants can be transported to nearby sources of drinking water and air in residential areas, leading to potential ingestion exposure to contaminants dissolved in water and inhalation exposure to contaminated particles in air.

Decreases in coal production levels may improve air quality in adjacent communities due to a lower overall exposure to coal dust and particulate matter, which may increase risk of adverse health effects including various malignant and nonmalignant lung and bladder diseases. As noted above, however, the Proposed Rule is not expected to have a significant effect on coal production. As a result, this analysis finds that the primary public health benefits of the Action Alternatives are associated with the expected improvements to water resources rather than air quality improvements.

Ideally, this analysis would combine information on the expected water quality benefits in each region, with information on the potentially vulnerable population (e.g., exposed via drinking water or fish consumption). Absent specific information on the locations of future mines, however, we cannot forecast the size of the population benefitting from improved water quality.

The stream miles quantified that will experience water quality improvements, however, indicate the potential for populations to benefit from reduced risk of water quality-related illness including selenosis, various gastrointestinal issues, and various cancers. The economics literature has found that the public places a significant value on protecting groundwater from contamination (Poe et al., 2001 provide a review of this literature) and that the public is willing to incur costs to avoid potential health risks (e.g., see Abdalla et al., 1992).[175] Both the size of the population benefitting and the particular level of risk reduction from improved water quality are, however, significantly uncertain.

RECREATION

Various provisions within the Proposed Rule have the potential to benefit recreational opportunities. For example:

- Improved water quality has the potential to enhance fishing and other water-based recreational opportunities;
- Habitat protection and enhancement and reforestation requirements have the potential to enhance species populations and benefit hunting and wildlife viewing; and
- Reforestation will improve the aesthetics of areas that may support recreation or are adjacent to and visible from recreational areas.

Each of these changes may increase participation in recreational activities in a given region and/or enhance the quality of the recreational experience (and the associated economic welfare derived from the activity). For example, Rosenberg and Loomis (2000) and Loomis (2005) provide a summary of the literature on the economic value of recreational opportunities.[176] For example, Loomis (2005) reports that across studies

[175] Poe, G., Boyle, K., and Bergstrom, J. 2001. A Preliminary Meta Analysis of Contingent Values for Ground Water Revisited. Chapter 8 in *The Economic Value of Water Quality*. Bergstrom, J., Boyle, K., and Poe, G. (eds.). Edward Elgar Publishing Limited: UK; Abdalla, C., Roach, B., and Epp, D. 1992. Valuing Environmental Quality Changes Using Averting Expenditures: An Application to Groundwater Contamination. Land Economics 68(2): 163-169.

[176] Rosenberger, R.S. and Loomis, J.B. 2000. Benefit Transfer of Outdoor Recreation Use Values: A Technical Document Supporting the Forest Service Strategic Plan (2000 Revision). USDA Forest Service; Loomis, J. 2005. Updated Outdoor Recreation Use Values on National Forests and Other Public Lands. U.S. Forest Service Pacific Northwest Research Station General Technical Report PNW-GTR-658.

conducted over the last several decades, the average per-day value for fishing, wildlife viewing and hiking is $56, $50, and $37, respectively (2011 dollars).[177]

Per-day willingness-to-pay figures provide a rough indication of the potential economic value associated with improved recreational opportunities. A comprehensive benefits transfer analysis would combine these willingness-to-pay estimates with estimated increases in participation to estimate the total increase in economic welfare associated with the resource improvements. Establishing a link between the improvements and activity levels is complex, however. Available data on hunting, fishing, and wildlife viewing suggest that baseline levels of outdoor recreational activity are high in many of the coal regions; however, the link between resource improvements (e.g., water quality improvements, improved reforestation) and increased participation is highly uncertain.[178] Therefore, this analysis is limited to a qualitative characterization of potential recreational benefits.

OTHER IMPACTS

Reduced Risk of Long-Term Water Quality Impairments

Subsequent to mining and reclamation performed under current regulations, pollution discharges may occur that require long-term treatment by the mine operator, or in the case of bond forfeiture, by the regulatory authority. Although the incidence of such discharges has decreased dramatically in recent years due to improved hydrologic modeling and mining practices, pollution discharges (e.g., acid or toxic mine drainage) requiring long-term treatment still occur. Recent OSMRE annual reports (EY 2010-2011) indicate that several states have active mines requiring water treatment, and inventories of bond forfeiture sites in several states indicate that significant long-term water treatment liabilities remain. In addition emerging water treatment issues requiring active treatment for total dissolved solids and selenium at coal mining operations may add to the potential liabilities for long-term treatment.

The Proposed Rule contains various provisions that may result in the prevention of such long-term pollution problems. Notable elements include improved baseline data collection, mandatory regulatory authority evaluation of monitoring data, and enhanced mining and reclamation techniques addressing fill construction. While difficult to quantify specifically, it is anticipated that mining operations conducted in accordance with the Proposed Rule will be less likely to develop long-term contamination issues, with a resultant savings in water treatment costs to both the industry and state regulatory authorities.

177 Loomis, J. 2005. Updated Outdoor Recreation Use Values on National Forests and Other Public Lands. U.S. Forest Service Pacific Northwest Research Station General Technical Report PNW-GTR-658.

178 U.S. Census Bureau. 2011. National Survey of Fishing, Hunting, and Wildlife-Associated Recreation. U.S. Fish and Wildlife Service, U.S. Department of the Interior.

Reduced Risk of Climate Change-Related Damages

Carbon dioxide (CO_2) is the principal greenhouse gas resulting from human activities. To the extent that a rulemaking influences CO_2 emissions, it may also influence a variety of socioeconomic outcomes related to climate change, including agricultural productivity, human health, increased flooding damages, and various ecosystem services. The Interagency Working Group on the Social Cost of Carbon has issued guidelines to help agencies assess the climate change-related benefits of reducing CO_2 emissions and integrate these estimates into their assessments of regulatory impacts.[179]

While this Guidance provides a foundation for monetizing an estimated reduction in atmospheric carbon, its application relies on a reasonable estimate of a change in carbon in the atmosphere resulting from the Proposed Rule. In the context of the Proposed Rule, a variety of factors undermine a reliable estimation of the magnitude of this effect. First and most fundamentally, it is difficult to assess the net effect of the Proposed Rule on CO_2 emissions from coal mining. As noted in the air quality discussion, available evidence suggests that the SPR may have various offsetting effects on greenhouse gas emissions. For instance, increased use of hauling vehicles could increase CO_2 emissions. Conversely, the approximately 2,811 acres of forest reestablished or undisturbed annually increases the carbon sequestration capacity of the landscape during and post-mining activities.[180] Second, the Proposed Rule could influence coal use at power plants and thereby affect the emission of greenhouse gases at successive stages of energy production. Modeling suggests that the Proposed Rule could decrease national coal production; however, predicting the direction and magnitude of impacts on U.S. greenhouse gas emissions is highly complex. The impact depends on factors such as the change in coal prices, the technological flexibility that power producers have to switch to substitute fuels, the price trends for those substitutes, the emissions profile for those substitutes, changes in coal export markets, and a variety of other considerations. This mix of factors makes an analysis of downstream greenhouse gas emissions – and hence carbon social costs – highly uncertain.

7.4 LIMITATIONS AND UNCERTAINTIES

The analyses presented in this chapter reflect the same uncertainties described in previous chapters, most notably with respect to: (1) the extent to which compliance costs and associated operational changes are accurately depicted and sufficiently representative within the model mine analysis; and (2) the accuracy of coal demand and supply forecasts. Additional limitations include the inability to accurately and reliably monetize quantified benefits associated water quality and biological resource improvements, as well as the inability to develop a quantitative characterization of benefits accruing to public health, air quality, and recreation.

[179] See Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on the Social Cost of Carbon, May 2013.

[180] Note that while acres undisturbed avoid loss of storage immediately, reestablished forest may take up to 125 years to realize full storage capacity at maturity (Smith, et al., 2005).

CHAPTER 8 | ANALYSIS OF ALTERNATIVES

This chapter provides a summary of benefits, compliance costs, market welfare effects and distributional effects associated with the SPR under Action Alternatives 2-9, excluding Alternative 8, the Proposed Rule. This information is provided to detail the potential cost impacts of Alternatives to the Proposed Rule on both industry and governments.

8.1 SUMMARY OF FINDINGS OF ALTERNATIVES ANALYSIS

This analysis estimates the incremental benefits, compliance costs, market welfare effects and distributional effects associated with the Alternatives to the Proposed Rule (i.e., the changes in these costs expected due to the Alternatives to the Proposed Rule over and above baseline costs that would be incurred in the absence of the alternative). The methods behind these calculations are the same as used to calculate effects of the Proposed Rule and are discussed in the previous chapters of this RIA.

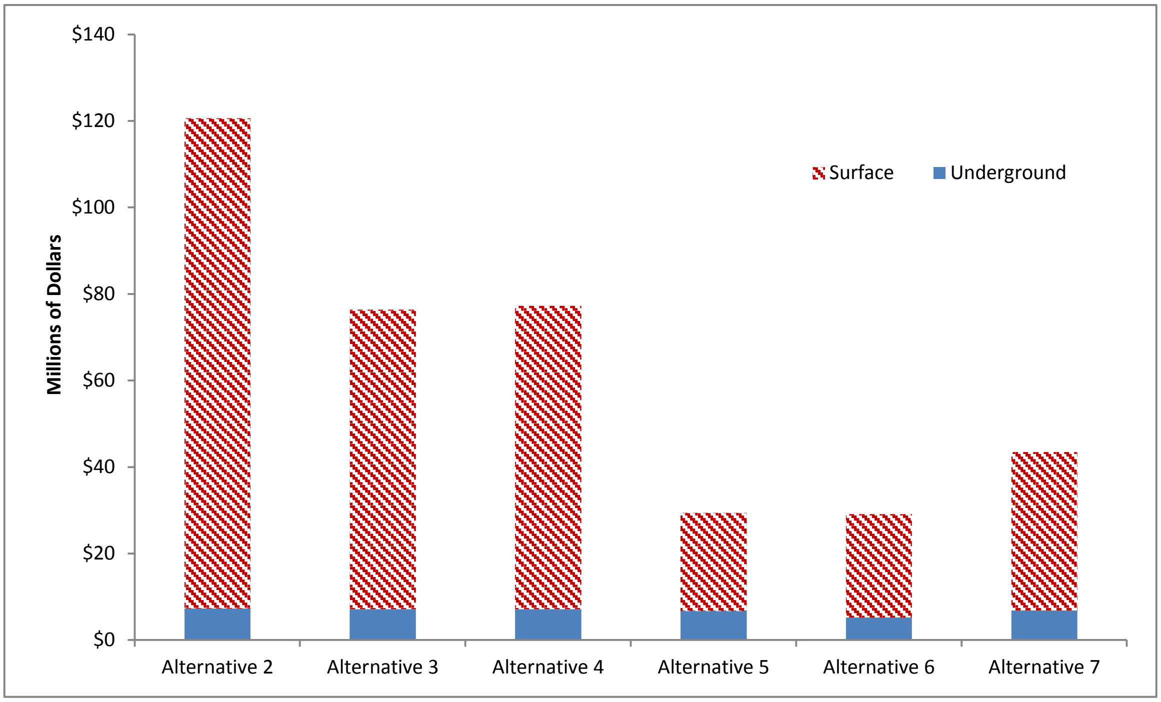
This section also presents a summary of findings across all alternatives and highlights the differences in costs and benefits between them. For the reasons explained in section 8.8, Alternative 9 is assumed to be the same as the baseline and thus is not presented in the summary tables. Increased costs and benefits related to Action Alternatives 2-7 are provided below. The sections that follow provide more detailed findings as they relate to each alternative.

EXHIBIT 8-1. COMPLIANCE COSTS, ANNUALIZED, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

COAL REGION	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachia	$71,000,000	$39,300,000	$37,700,000	$29,400,000	$12,300,000	$35,600,000
Colorado Plateau	$3,990,000	$3,700,000	$4,440,000	$0	$552,000	$2,400,000
Gulf Coast	$9,020,000	$8,510,000	$ 9,050,000	$0	$853,000	$1,490,000
Illinois Basin	$27,300,000	$16,700,000	$17,100,000	$0	$14,000,000	$2,530,000
Northern Rocky Mountains	$7,980,000	$7,450,000	$8,190,000	$0	$852,000	$1,290,000
Northwest	$153,000	$126,000	$132,000	$0	$43,700	$13,600
Western Interior	$1,100,000	$664,000	$670,000	$0	$554,000	$101,000
U.S. TOTAL	**$121,000,000**	**$76,400,000**	**$77,300,000**	**$29,400,000**	**$29,100,000**	**$43,500,000**

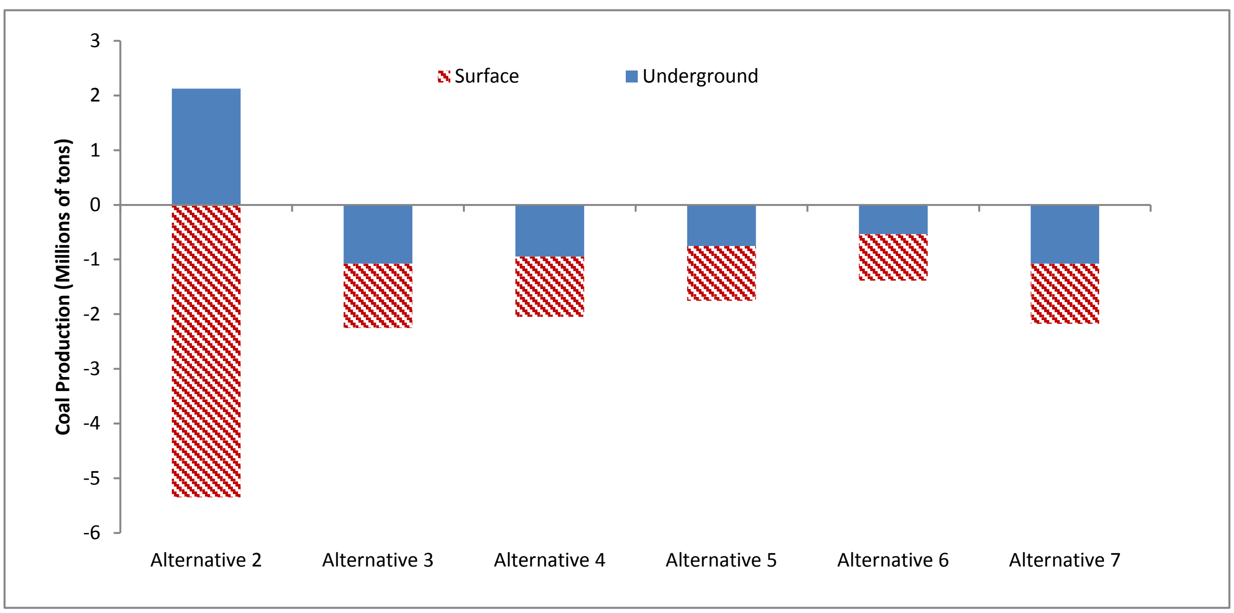
Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-2. COMPLIANCE COSTS, ANNUALIZED, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)



Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-3. AVERAGE ANNUAL CHANGE IN COAL PRODUCTION, 2020-2040



Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-4. INCREASED OPERATIONAL COMPLIANCE COSTS PER TON BY MODEL MINE

REGION	MODEL MINE	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachian Basin	CAPP – Surface Area	$1.76	$0.32	$0.41	$0.32	$0.18	$0.42
	CAPP – Surface Contour	$2.14	$1.11	$0.78	$0.55	$0.19	$0.79
	NAPP – Surface Contour	$0.63	$0.58	$0.88	$0.58	$0.05	$0.93
	CAPP – UG R&P	$0.02	$0.02	$0.02	$0.02	$0.00	$0.02
	NAPP – UG LW	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01
Colorado Plateau	Surface – Area	$0.17	$0.16	$0.20	$0.00	$0.02	$0.18
	Underground - Longwall	$0.01	$0.01	$0.01	$0.00	$0.00	$0.01
Gulf Coast	Surface – Area	$0.22	$0.21	$0.22	$0.00	$0.02	$0.18
Illinois Basin	Surface – Area	$1.18	$0.70	$0.72	$0.00	$0.60	$1.09
	Underground – Room and Pillar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Underground - Longwall	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Northern Rockies	Surface – Area	$0.02	$0.02	$0.02	$0.00	$0.00	$0.02
Northwest	Surface – Area	$0.09	$0.08	$0.08	$0.00	$0.02	$0.08
Western Interior	Surface – Area	$1.18	$0.70	$0.71	$0.00	$0.60	$1.09
	Underground – Room and Pillar	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.							

EXHIBIT 8-5. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS ALTERNATIVES 2-7, SEVEN PERCENT DISCOUNT RATE, 2020-2040 (MILLIONS, 2014 DOLLARS)[1]

YEAR	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
2020	$90.0	$45.4	$53.4	$2.7	($0.1)	$12.5
2021	$87.2	$50.9	$49.8	$9.5	$0.4	$12.3
2022	$75.6	$34.7	$41.3	($5.7)	($0.4)	$10.8
2023	$67.8	$40.2	$36.6	($0.1)	$0.5	$11.2
2024	$78.2	$42.3	$44.4	$12.0	$10.7	$21.0
2025	$71.3	$37.2	$41.5	$6.9	$4.8	$14.4
2026	$63.7	$36.1	$32.1	$8.6	$6.0	$15.2
2027	$59.4	$32.1	$33.7	$5.8	$3.3	$11.9
2028	$55.3	$30.9	$30.7	$5.5	$5.4	$13.5
2029	$54.7	$35.9	$30.9	$8.9	$8.8	$16.4
2030	$50.2	$28.3	$29.4	$7.5	$6.7	$13.8
2031	$45.5	$28.6	$27.0	$7.0	$7.7	$14.4
2032	$44.5	$28.9	$27.1	$9.4	$8.3	$14.6
2033	$38.0	$23.8	$25.0	$7.5	$6.6	$12.6
2034	$35.3	$22.1	$22.9	$8.0	$5.4	$11.0
2035	$33.4	$21.2	$21.5	$7.6	$6.6	$11.7
2036	$30.8	$19.5	$20.2	$6.6	$5.7	$10.4
2037	$29.0	$18.7	$18.8	$6.8	$5.6	$10.0
2038	$27.9	$18.1	$18.6	$6.9	$6.6	$10.5
2039	$25.2	$16.4	$16.7	$5.9	$5.7	$9.1
2040	$22.4	$14.6	$15.0	$5.4	$5.0	$8.1
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$100.2**	**$57.8**	**$58.7**	**$12.2**	**$10.1**	**$24.5**

[1] See Chapter 5 for a detailed description of these costs.

Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-6A. SUMMARY OF ANNUAL PRODUCTION-RELATED REGIONAL ECONOMIC IMPACTS OF THE RULE ALTERNATIVES, 2020-2040: EMPLOYMENT EFFECTS (FTE)

COAL REGION	METRIC	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachian Basin	Average over 21 years:[2]	(520)	(310)	(250)	(220)	(120)	(270)
	Range in any year:[3]	(890) - (130)	(540) - (76)	(450) - (62)	(470) - (41)	(230) - (13)	(510) - (62)
Colorado Plateau	Average over 21 years:	0	0	0	0	0	0
	Range in any year:	0 - 0	(1) - 0	0 - 1	0 - 1	(1) - 0	0 - 1
Gulf Coast	Average over 21 years:	1	(1)	(1)	0	1	0
	Range in any year:	0 - 3	(4) - 0	(6) - 0	(1) - 2	0 - 4	(1) - 1
Illinois Basin	Average over 21 years:	(48)	(31)	(33)	(16)	(28)	(45)
	Range in any year:	(140) - (1)	(100) - (2)	(110) - (1)	(60) - (1)	(130) - 1	(170) - (2)
Northern Rocky Mountains and Great Plains	Average over 21 years:	(21)	(22)	(22)	(22)	(21)	(22)
	Range in any year:	(61) - 0	(66) - 0	(51) - (1)	(70) - 0	(60) - 0	(54) - 0
Northwest	Average over 21 years:	0	0	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Western Interior	Average over 21 years:	0	0	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
U.S. TOTAL	**Average over 21 years:**	**(590)**	**(360)**	**(310)**	**(260)**	**(160)**	**(330)**
	Range in any year:	**(1,100) - (130)**	**(660) - (78)**	**(580) - (62)**	**(530) - (48)**	**(340) - (14)**	**(680) - (65)**

[1] Production-related employment effects are reported as an average and a range of expected annual effects. Employment effects from production are calculated using employment per ton of coal produced. The range of employment effects represent the minimum and maximum effect in any year in the study period when impacts on surface mining as well as underground mining employment are combined.

[2] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment.

[3] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.

EXHIBIT 8-6B. SUMMARY OF ANNUAL COMPLIANCE-RELATED REGIONAL ECONOMIC IMPACTS OF THE RULE ALTERNATIVES, 2020-2040: EMPLOYMENT EFFECTS (FTE)

COAL REGION	METRIC	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachian Basin	Average over 21 years:[2]	340	190	180	140	59	170
	Range in any year:[3]	280 - 370	160 - 200	150 - 190	120 - 150	49 - 63	140 - 180
Colorado Plateau	Average over 21 years:	20	19	23	0	3	12
	Range in any year:	17 - 22	16 - 20	19 - 24	0 - 0	2 - 3	10 - 13
Gulf Coast	Average over 21 years:	44	42	45	0	4	7
	Range in any year:	44 - 45	42 - 42	44 - 45	0 - 0	4 - 4	7 - 7
Illinois Basin	Average over 21 years:	130	79	81	0	66	12
	Range in any year:	100 - 150	62 - 91	63 - 94	0 - 0	52 - 76	9 - 14
Northern Rocky Mountains and Great Plains	Average over 21 years:	35	33	36	0	4	6
	Range in any year:	31 - 37	29 - 35	32 - 38	0 - 0	3 - 4	5 - 6
Northwest	Average over 21 years:	1	1	1	0	0	0
	Range in any year:	1 - 1	1 - 1	1 - 1	0 - 0	0 - 0	0 - 0
Western Interior	Average over 21 years:	5	3	3	0	3	0
	Range in any year:	5 - 5	3 - 3	3 - 3	0 - 0	3 - 3	0 - 1
U.S. TOTAL	**Average over 21 years:**	**580**	**370**	**370**	**140**	**140**	**210**
	Range in any year:	**470 - 630**	**310 - 390**	**310 - 390**	**120 - 150**	**110 - 150**	**180 - 220**

[1] Compliance-related employment effects are reported as an average and a range of expected annual effects. Employment effects from compliance are calculated using expected changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance The range of employment effects represent the minimum and maximum effect in any year in the study period.

[2] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment.

[3] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.

EXHIBIT 8-6C. SUMMARY OF ANNUAL REGIONAL ECONOMIC IMPACTS OF THE THE RULE ALTERNATIVES, SEVEN PERCENT DISCOUNT RATE, 2020-2040: ANNUALIZED SEVERANCE TAXES

COAL REGION	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachian Basin[1]	($4,320,000)	($2,500,000)	($2,040,000)	($1,790,000)	($1,010,000)	($2,190,000)
Colorado Plateau	$108	($574)	$745	$453	$168	$1,130
Gulf Coast	$66	($76)	($161)	$31	$90	$10
Illinois Basin[1]	($785,000)	($411,000)	($349,000)	($259,000)	($205,000)	($402,000)
Northern Rocky Mountains and Great Plains	($444,000)	($464,000)	($441,000)	($455,000)	(435,000)	(448,000)
Northwest	$0	$0	$0	$0	$0	$0
Western Interior	$0	$0	$0	$0	$0	$0
U.S. TOTAL	**($5,550,000)**	**($3,370,000)**	**($2,830,000)**	**($2,510,000)**	**($1,640,000)**	**($3,040,000)**

[1] Production in Kentucky is evenly divided between the Appalachian Basin and Illinois Basin regions.

Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-7. SUMMARY OF TOTAL ENVIRONMENTAL AND HUMAN HEALTH IMPACTS: 2020-2040

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7	EFFECT ON ECOSYSTEM SERVICES
Water Quality	Fewer stream miles adversely impacted, improved water quality (e.g., pH, selenium, TDS) within watershed. Potential for adverse and beneficial impacts to groundwater quality and quantity (contamination and well loss)	Stream restoration, landforming, fill design changes, and reforestation requirements; indirect effects of changes in mining activity	8 stream miles not filled; 57 stream miles restored; 26 downstream preserved stream miles; 267 downstream improved stream miles per year	0 stream miles not filled; 29 stream miles restored; 1 downstream preserved stream mile; 291 downstream improved stream miles per year	4 stream miles not filled; 29 stream miles restored; 1 downstream preserved stream mile; 291 downstream improved stream miles per year	4 stream miles not filled; 1 stream mile restored; 1 downstream preserved stream mile; 174 downstream improved stream miles per year	4 stream miles not filled; 30 stream miles restored; 1 downstream preserved stream mile; 292 downstream improved stream miles per year	4 stream miles not filled; 14 stream miles restored; 1 downstream preserved stream mile; 178 downstream improved stream miles per year	Increased water quality enhances ecosystem, recreational, and some consumptive use services
Biological Resources	Reduced impacts to aquatic communities, habitat enhancements for threatened and endangered species	Stream restoration, landforming, reforestation and species protection requirements	Water quality benefits stated above; 2,343 acres of forest improved; 311 acres of forest preserved per year	Water quality benefits stated above; 2,836 acres of forest improved; 31 acres of forest preserved per year	Water quality benefits stated above; 2,808 acres of forest improved; 25 acres of forest preserved per year	Water quality benefits stated above; 1,346 acres of forest improved; 21 acres of forest preserved per year	Water quality benefits stated above; 0 acres of forest improved; 11 acres of forest preserved per year	Water quality benefits stated above; 1,764 acres of forest improved; 26 acres of forest preserved per year	Increased quality or quantity of habitat enhances recreational opportunities and aesthetic conditions
Visual Resources	Improved aesthetics	AOC requirements, landforming and reforestation requirements	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Biological resource benefits as stated above	Improved aesthetics may improve property values and the quality of recreational opportunities

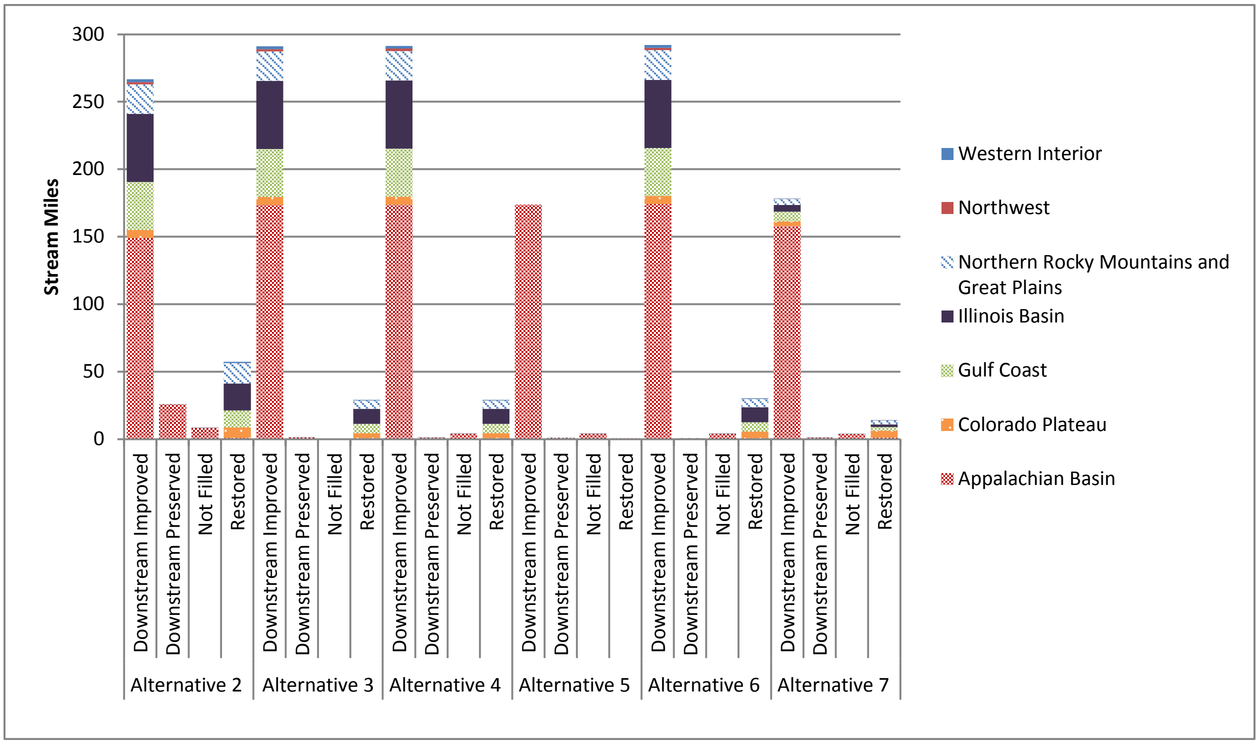
CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7	EFFECT ON ECOSYSTEM SERVICES
Air Quality	Additional carbon storage, changes in emissions (e.g., NO_X, SO_2, PM, CH_4) from mining activity	Reforestation requirements, fill design changes, indirect effects of changes in mining activity[1]	Increased reforestation (see Biological resources above) and associated increased carbon storage; increased air pollutant emissions due to increased underground mining activity (e.g., methane emissions increase by approximately 363 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 400 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 353 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 283 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 204 MMcf per year)	Increased reforestation (see Biological resources above) and associated increased carbon storage; reduced air pollutant emissions due to decreased mining activity (e.g., methane emissions decrease by approximately 396 MMcf per year)	Increased carbon storage and reductions in emissions reduce human health risks and climate change-related risks
Public Health	Reduced exposure to contaminants in drinking water	Stream restoration, landforming, and reforestation requirements	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Water quality resource benefits as stated above	Reduced probability of adverse health effects due to contaminated water, or incurring costs to mitigate those effects

CATEGORY	IMPACT	RULE ELEMENT GENERATING IMPACT	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7	EFFECT ON ECOSYSTEM SERVICES
Recreation	Potential for increased recreational opportunities, improved aesthetics	Elements directly affecting water quality and biological resources (e.g., stream restoration) as well as AOC requirements and post-mining land use	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Water quality and biological resource benefits as stated above	Increased quality or quantity of recreational fishing, hunting, wildlife viewing, or hiking opportunities
Other	Reduced risk and severity of adverse impacts, including long-term pollution discharges during and after mining	Baseline data collection, monitoring, material damage definition, corrective action thresholds	Water, biological, and air quality resource benefits as stated above	Water, biological, and air quality resource benefits as stated above	Water, biological, and air quality resource benefits as stated above	Water, biological, and air quality resource benefits as stated above	Water, biological, and air quality resource benefits as stated above	Water, biological, and air quality resource benefits as stated above	Reduced risk of long-term water quality contamination and potential reduced risk of climate change-related damages

Notes:
As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

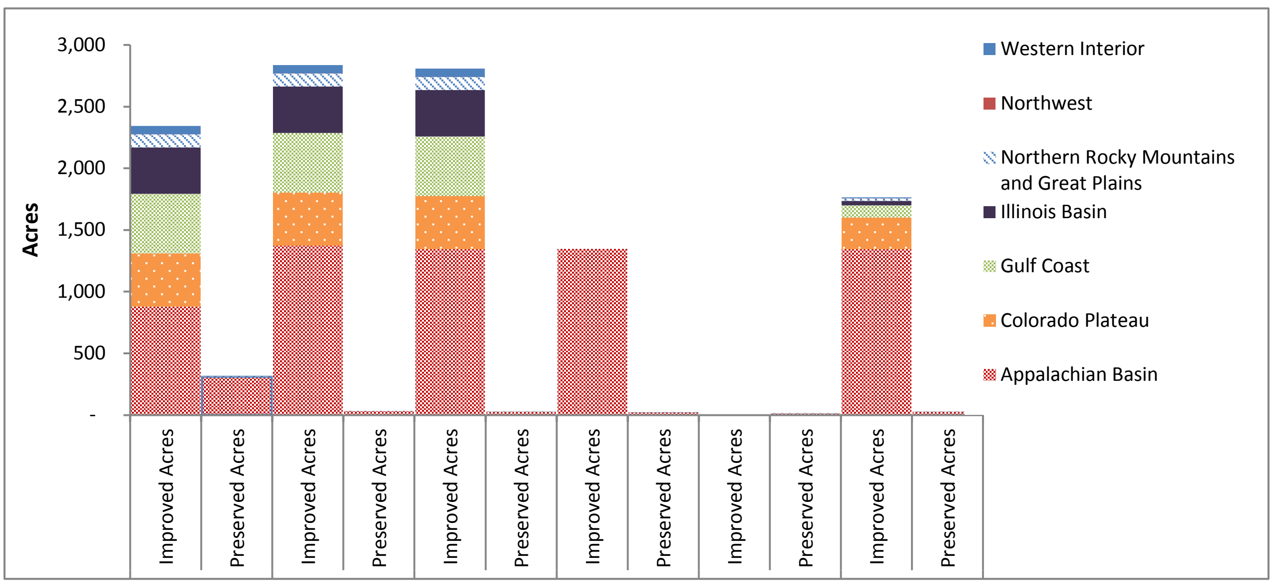
[1] The potential for the Alternatives to reduce air pollutant emissions is due to the aggregate effect of the rule elements on the overall level of coal mining activity. The relative effect of the Alternatives on coal production is therefore an indicator of the potential relative effect on emissions. The relative effects of the Alternatives on coal production are presented in Exhibit ES-11.

EXHIBIT 8-7A. STREAM AND WATER QUALITY IMPACTS - AVERAGE ANNUAL STREAM MILES, 2020-2040



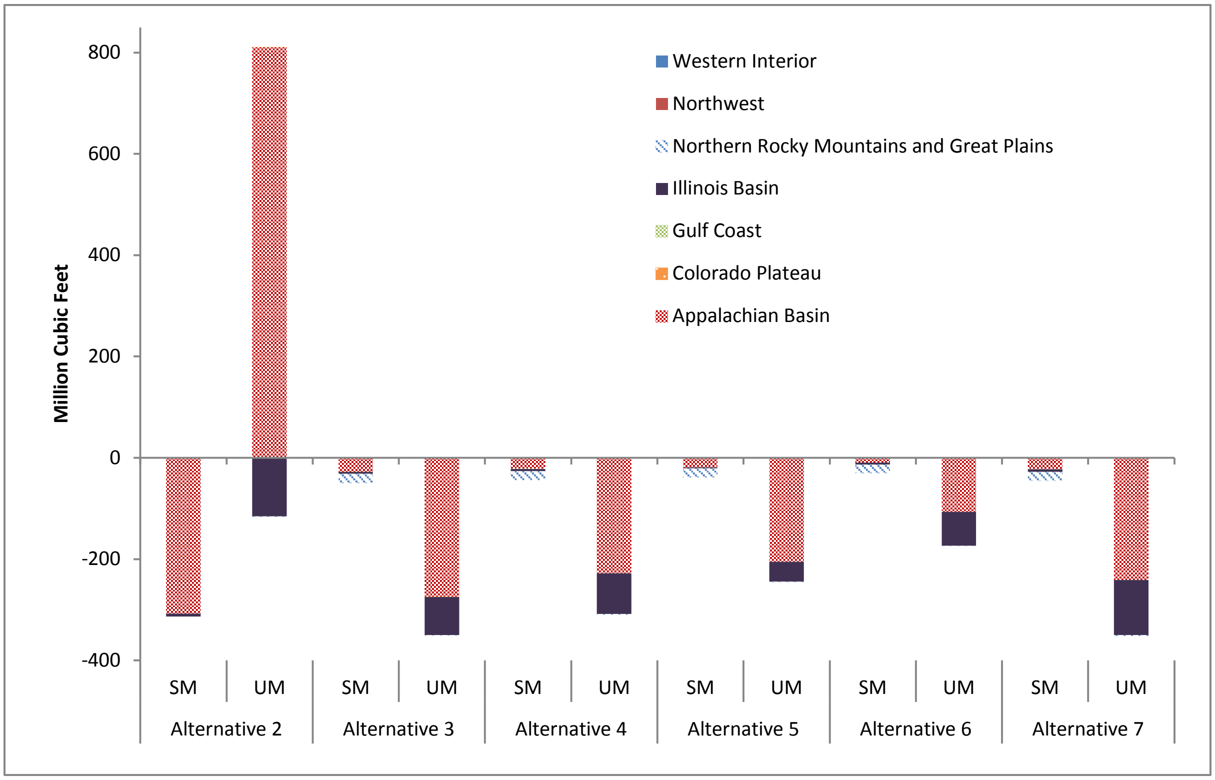
Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-7B. FOREST AREA IMPACTS - AVERAGE ANNUAL ACRES, 2020-2040



Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

EXHIBIT 8-7C. AVERAGE ANNUAL CHANGES IN METHANE EMISSIONS, 2020-2040 (MMCF)



Note: As most current mining practices are consistent with the SBZ, Alternative 9 is anticipated to have negligible impacts and thus is not included in the exhibit.

8.2 ALTERNATIVE 2

Alternative 2 would prohibit all mining activities in or within 100 feet of perennial streams. It would allow "mining through" intermittent streams only if the applicant can demonstrate that the hydrologic form and ecological function of intermittent streams can and would be restored. It would prohibit the placement of excess spoil in both perennial and intermittent streams. It would place no new restrictions on activities in ephemeral streams. It would allow no exceptions from the requirement to restore mined lands to their approximate original contour, and it would require an amendment to SMCRA.

This Alternative would define the term "material damage to the hydrologic balance outside the permit area" as "any quantifiable adverse impact from surface or underground mining operations that would preclude any designated use of the affected stream segment under the Clean Water Act". This Alternative would require that the permit include corrective action thresholds. The following sections detail the potential effects of the Proposed Rule under this Alternative.

COMPLIANCE COSTS

Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculated the total compliance cost effects for Alternative 2. These results, annualized, are provided in Exhibit 8-8.

EXHIBIT 8-8. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 2, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE	TOTAL
Appalachia	Surface	$61,700,000	$2,550,000	$2,590	$64,300,000
	UG	$1,720,000	$5,040,000	$7,250	$6,760,000
Colorado Plateau	Surface	$3,660,000	$130,000	$1,340	$3,790,000
	UG	$120,000	$80,400	$985	$201,000
Gulf Coast	Surface	$8,680,000	$339,000	$2,600	$9,020,000
Illinois Basin	Surface	$26,400,000	$644,000	$1,500	$27,000,000
	UG	$0	$261,000	$4,940	$266,000
Northern Rocky Mountains and Great Plains	Surface	$7,750,000	$204,000	$24,200	$7,980,000
Northwest	Surface	$134,000	$18,900	$98	$153,000
Western Interior	Surface	$1,070,000	$26,100	$61	$1,090,000
	UG	$0	$526	$5	$530
Annualized U.S. Compliance Cost Impacts	Surface	$109,000,000	$3,910,000	$32,400	$113,000,000
	UG	$1,840,000	$5,380,000	$13,200	$7,230,000
	TOTAL	**$111,000,000**	**$9,290,000**	**$45,600**	**$121,000,000**
Note: Totals may not sum due to rounding.					

MARKET WELFARE EFFECTS

Changes in Coal Production

Exhibits 8-9 and 8-10 show the projected change in coal production from 2020 through 2040 under Alternative 2. Under this Alternative, increased costs result in a shift of some surface coal production to underground production starting in 2025. As shown in Exhibit 8-9, surface mines account for the vast majority of the decline in production under this alternative. The net reduction in the volume of coal produced is forecast to lessen over the time period for the analysis, consistent with the declining demand for U.S. coal from retiring coal-fired power plants. In aggregate, however, the reduction in coal production under Alternative 2 is nearly double those in the Proposed Rule. Exhibit 8-10 shows that more than half this reduction is in the Appalachian Basin. Exhibit 8-11 displays the additional operational costs per ton for each model mine under Alternative 2. In general, the expected change in operational costs per ton are higher for surface mines than they are for underground mines, and the Appalachian Basin is expected to experience the largest change.

EXHIBIT 8-9. ANNUAL CHANGES IN COAL PRODUCTION UNDER ALTERNATIVE 2

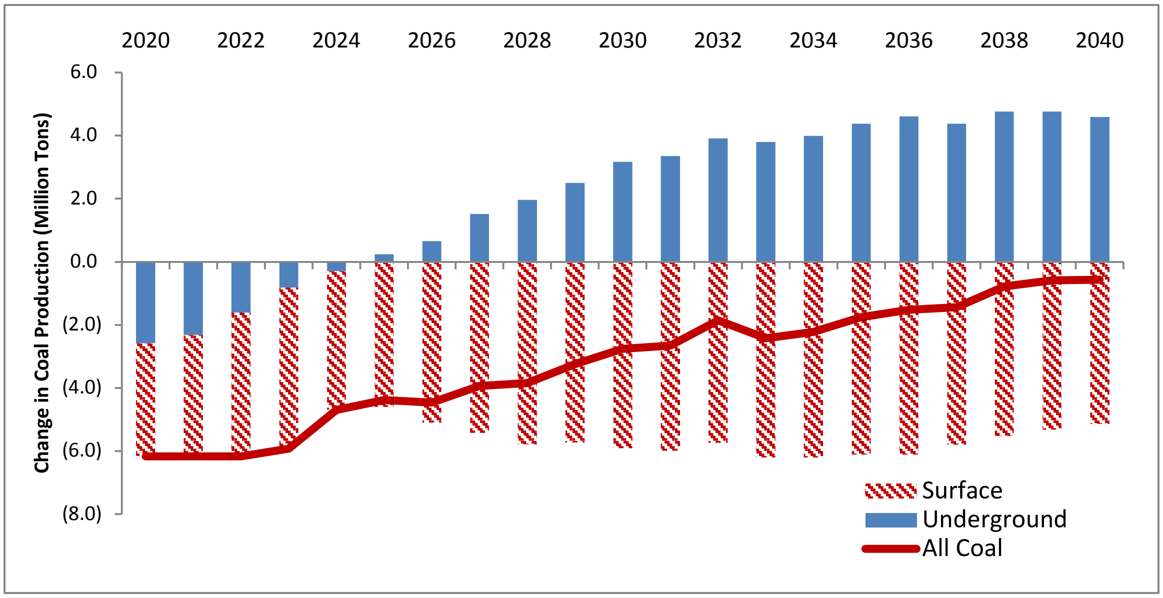
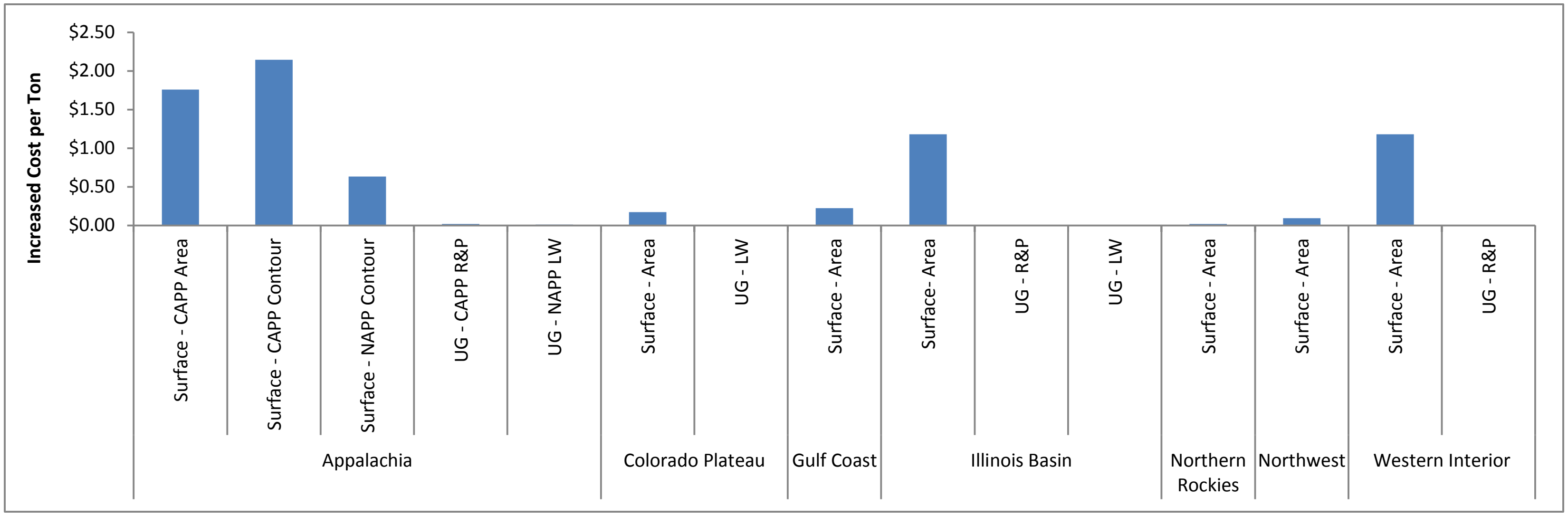


EXHIBIT 8-10. AVERAGE ANNUAL COAL PRODUCTION, 2020-2040

COAL REGION	BASELINE (MILLION TONS)	ALTERNATIVE 2 (MILLION TONS)	CHANGE (MILLION TONS)
Appalachian Basin	236	234	(2.1)
Colorado Plateau	56	56	0
Gulf Coast	54	54	0
Illinois Basin	171	170	(0.4)
North Rocky Mountains/Great Plains	533	532	(0.7)
Northwest	2	2	0
Western Interior	1	1	0
TOTAL	**1,053**	**1,050**	**(3.2)**

EXHIBIT 8-11. INCREASED OPERATIONAL COST PER TON BY MODEL MINE, ALTERNATIVE 2



Coal Price Impacts

Related to changes in regional coal production, compliance costs, and coal market behavior, Exhibit 8-12 presents the estimated changes in coal prices under Alternative 2 for selected coal regions. The price projections presented in the exhibit suggest that regional coal prices will increase by 0.2 to 4.7 percent under Alternative 2. The increases are most significant in Central Appalachia.

EXHIBIT 8-12. COAL PRICE IMPACTS OF ALTERNATIVE 2 ($/TON)

REGION	2015 BASELINE	2015 ALT. 2	2020 BASELINE	2020 ALT. 2	2030 BASELINE	2030 ALT. 2	2040 BASELINE	2040 ALT. 2
NAPP	56.04	56.04	58.26	58.42	63.03	63.19	69.98	70.14
CAPP	64.00	64.00	67.34	70.52	70.43	73.60	74.27	77.44
ILLB	42.48	42.48	44.75	45.15	46.15	46.57	47.72	48.13
PRB	14.19	14.19	16.02	16.06	17.33	17.38	19.57	19.62
RCK	36.24	36.24	38.50	38.61	38.95	39.05	39.60	39.70

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin
PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.

Market Welfare Effects

Exhibit 8-13 presents the estimated change in market welfare, by year and in aggregate, for Alternative 2 over the 2020-2040 period. Similar to the Proposed Rule, market welfare losses for Alternative 2 largely reflect regulatory compliance costs and a transportation cost savings. This decrease in transportation costs suggests that under Alternative 2, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers.

EXHIBIT 8-13. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS OF ALTERNATIVE 2, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$90.0	$0.04	$90.0
2021	$87.1	$0.04	$87.2
2022	$75.5	$0.04	$75.6
2023	$67.7	$0.04	$67.8
2024	$78.1	$0.03	$78.2
2025	$71.2	$0.03	$71.3
2026	$63.7	$0.03	$63.7
2027	$59.3	$0.03	$59.4
2028	$55.3	$0.03	$55.3
2029	$54.7	$0.02	$54.7
2030	$50.2	$0.02	$50.2
2031	$45.4	$0.02	$45.5
2032	$44.5	$0.02	$44.5
2033	$38.0	$0.02	$38.0
2034	$35.3	$0.02	$35.3
2035	$33.4	$0.01	$33.4
2036	$30.8	$0.01	$30.8
2037	$29.0	$0.01	$29.0
2038	$27.9	$0.01	$27.9
2039	$25.2	$0.01	$25.2
2040	$22.4	$0.01	$22.4
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$100.1**	**$0.05**	**$100.2**

DISTRIBUTIONAL EFFECTS

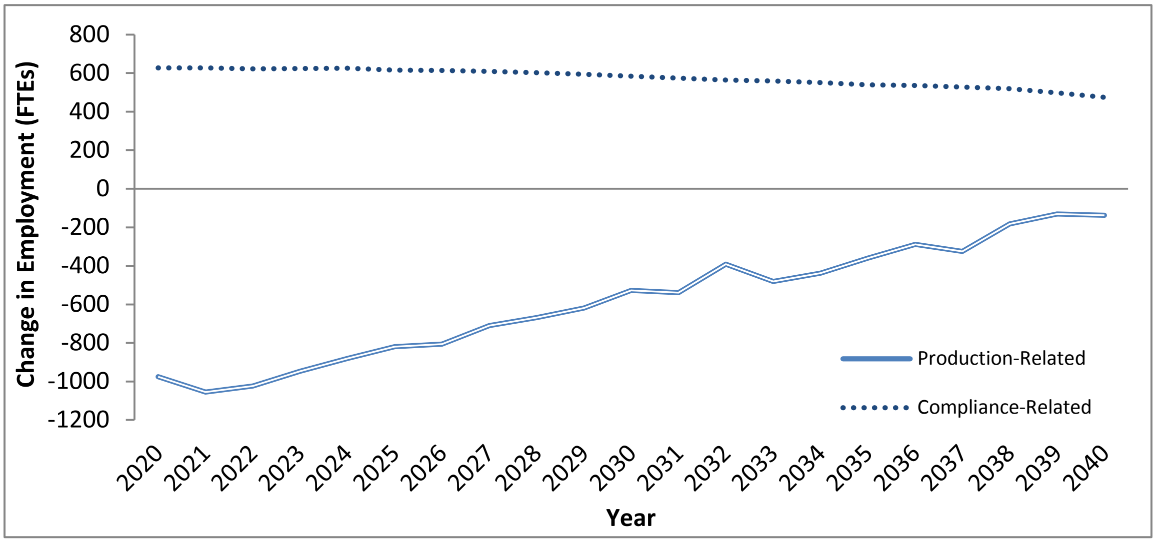
We estimate the changes in employment that are expected under Alternative 2, relative to the baseline. As shown in Exhibit 8-14A, production-related annual impacts to employment are expected to range from a reduction in demand for 1,100 FTEs to a reduction of 130 across all regions, with an average reduction in annual demand of 590 FTEs. Across all regions compliance-related employment effects are expected to range from an increase of 470 to 630 FTEs with an average annual increase of 580. Exhibit 8-14B shows the production-related and compliance-related effects as a line graph from 2020 to 2040.

EXHIBIT 8-14A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 2, 2020-2040, EMPLOYMENT DEMAND: (FTE)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(1,100)	610	(520)	340
	Range in any year:[2]	(1,400) - (400)	(390) – 1,200	(890) - (130)	280 – 370
Colorado Plateau	Average over 21 years:	0	0	0	20
	Range in any year:	0 - 0	0 - 0	0 - 0	17 - 22
Gulf Coast	Average over 21 years:	1	0	1	44
	Range in any year:	0 - 3	0 - 0	0 - 3	44 - 45
Illinois Basin	Average over 21 years:	(9)	(39)	(48)	130
	Range in any year:	(29) - 0	(110) - (1)	(140) - (1)	100 - 150
Northern Rocky Mountains and Great Plains	Average over 21 years:	(21)	0	(21)	35
	Range in any year:	(61) - 0	0 - 0	(61) - 0	31 - 37
Northwest	Average over 21 years:	0	0	0	1
	Range in any year:	0 – 0	0 - 0	0 - 0	1 - 1
Western Interior	Average over 21 years:	0	0	0	5
	Range in any year:	0 – 0	0 - 0	0 - 0	5 - 5
U.S. TOTAL	**Average over 21 years:**	**(1,200)**	**570**	**(590)**	**580**
	Range in any year:	**(1,500) - (480)**	**(500) - 1,200**	**(1,100) - (130)**	**470 - 630**

[1] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020-2040).
[2] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.
[3] "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
[5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 8-14B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 2 COMPATRED TO BASELINE, FTES, 2020 TO 2040



Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of Alternative 2. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is not produced because of changes associated with Alternative 2. This volume also becomes smaller over time given that the industry is getting smaller over time. "Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of Alternative 2 follow the pattern of overall forecast coal production. As shown, both the compliance-related and the production-related impacts of the Alternative are reduced over time. However, the slopes of these curves are not the same.

ENVIRONMENT AND HUMAN HEALTH

Exhibit 8-7 summarizes the categories of benefits and costs that are expected to result from Alternative 2 over the time frame of the analysis. Note that the categories are not mutually exclusive but rather complementary in several respects. For example, improved water quality will benefit biological resources, recreation, and may benefit human health. Exhibits 8-15A through C present the quantified impacts of Alternative 2, stream impacts, forest acre impacts, and air quality impacts.

EXHIBIT 8-15A. QUANTIFIED IMPACTS UNDER ALTERNATIVE 2 BY REGION: STREAM IMPACTS, AVERAGE ANNUAL STREAM MILES

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	149	26	8	1
Colorado Plateau	6	0	0	8
Gulf Coast	36	0	0	12
Illinois Basin	51	0	0	20
Northern Rocky Mountains and Great Plains	22	0	0	15
Northwest	2	0	0	0
Western Interior	2	0	0	1
Total	**267**	**26**	**8**	**57**

EXHIBIT 8-15B. QUANTIFIED IMPACTS UNDER ALTERNATIVE 2 BY REGION: FOREST AREA IMPACTS, AVERAGE ANNUAL FOREST ACRES

COAL REGION	IMPROVED ACRES	PRESERVED ACRES
Appalachian Basin	878	310
Colorado Plateau	431	0
Gulf Coast	483	0
Illinois Basin	377	1
Northern Rocky Mountains and Great Plains	105	0
Northwest	1	0
Western Interior	67	0
Total	**2,342**	**311**

EXHIBIT 8-15C. QUANTIFIED IMPACTS UNDER ALTERNATIVE 2 BY REGION: AVERAGE ANNUAL CHANGES IN METHANDE EMISSIONS (MMCF)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	(308)	811	503
Colorado Plateau	0	0	0
Gulf Coast	0	0	0
Illinois Basin	(6)	(116)	(122)
Northern Rocky Mountains and Great Plains	(17)	(1)	(18)
Northwest	0	0	0
Western Interior	0	0	0
Total	**(330)**	**694**	**363**
Note: Totals may not sum due to rounding. Negative numbers indicate a decrease of emissions and positive numbers indicate an increase of emissions.			

8.3 ALTERNATIVE 3

Alternative 3 would allow mining in or through intermittent and perennial streams, but only if the hydrologic form and ecological function of those streams can be restored. No restriction would be placed on mining in or through ephemeral streams. This Alternative would prohibit the placement of excess spoil or coal mine waste in perennial streams, but not in ephemeral or intermittent streams.

Exceptions to approximate original contour restoration requirements would be allowed only if they do not result in damage to natural watercourses on or off the permit area. This Alternative would define the term "material damage to the hydrologic balance outside the permit area" as any quantifiable adverse impact from surface or underground mining operations that would preclude any designated use of the affected stream segment under the Clean Water Act; the permit must include corrective action thresholds.

The following sections detail the potential effects of the Proposed Rule under this Alternative.

COMPLIANCE COSTS

Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculated the total compliance cost effects for Alternative 3. These results, annualized, are provided in Exhibit 8-16.

EXHIBIT 8-16. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 3, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE	TOTAL
Appalachia	Surface	$29,900,000	$2,720,000	$2,770	$32,600,000
	UG	$1,670,000	$4,970,000	$7,150	$6,640,000
Colorado Plateau	Surface	$3,360,000	$130,000	$1,340	$3,490,000
	UG	$120,000	$80,400	$985	$201,000
Gulf Coast	Surface	$8,160,000	$339,000	$2,600	$8,510,000
Illinois Basin	Surface	$15,800,000	$664,000	$1,500	$16,400,000
	UG	$0	$261,000	$5,000	$266,000
Northern Rocky Mountains and Great Plains	Surface	$7,230,000	$204,000	$24,200	$7,450,000
Northwest	Surface	$107,000	$18,900	$98	$126,000
Western Interior	Surface	$637,000	$26,100	$61	$663,000
	UG	$0	$526	$5	$530
Annualized U.S. Compliance Cost Impacts	Surface	$65,200,000	$4,090,000	$32,600	$69,300,000
	UG	$1,790,000	$5,310,000	$13,100	$7,110,000
	TOTAL	**$66,900,000**	**$9,400,000**	**$45,600**	**$76,400,000**
Note: Totals may not sum due to rounding.					

MARKET WELFARE EFFECTS

Changes in Coal Production

Exhibits 8-17 and 8-18 show the projected change in coal production from 2020 through 2040 under Alternative 3. Under this Alternative, reductions in coal production occur for both surface and underground mining. As shown in Exhibit 8-17, surface mines account for the majority of the decline in production under this alternative. The net reduction in the volume of coal produced is forecast to lessen over the time period for the analysis, consistent with the declining demand for U.S. coal from retiring coal-fired power plants. In aggregate, however, the reduction in coal production under Alternative 3 is slightly more than those in the Proposed Rule. Exhibit 8-18 shows that more than half this reduction is in the Appalachian Basin. Exhibit 8-19 displays the additional operational costs per ton for each model mine under Alternative 3. In general, the expected change in operational costs per ton are higher for surface mines than they are for underground mines, and the Appalachian Basin is expected to experience the largest change.

EXHIBIT 8-17. ANNUAL CHANGES IN COAL PRODUCTION UNDER ALTERNATIVE 3

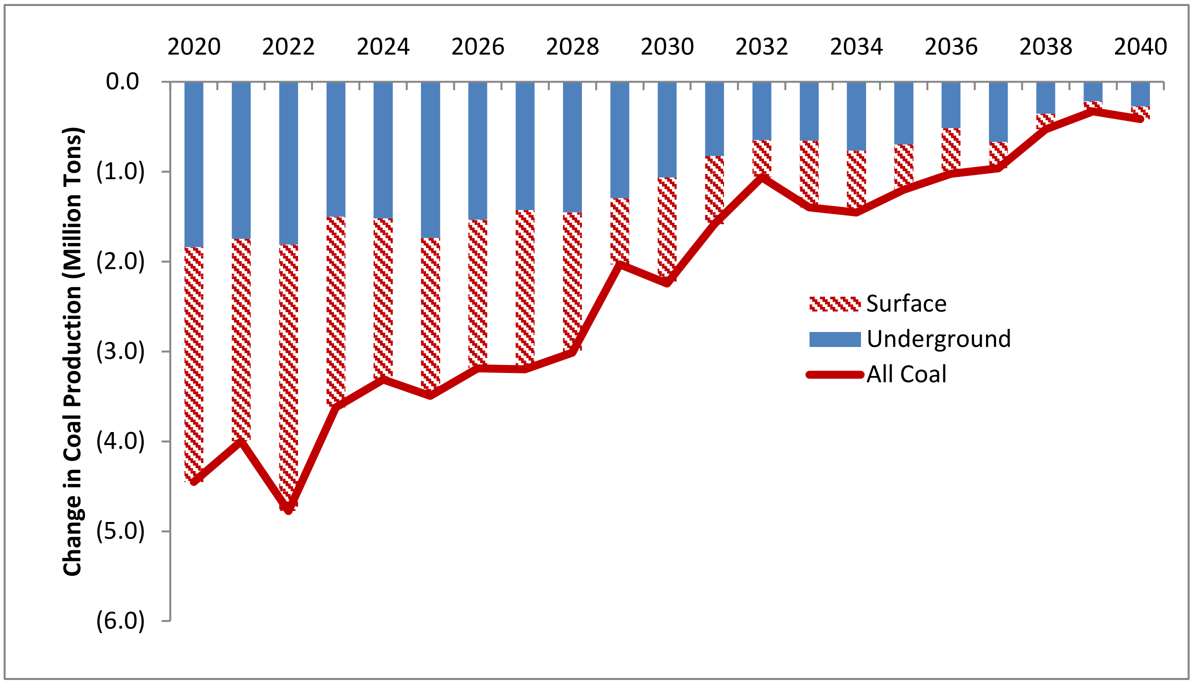
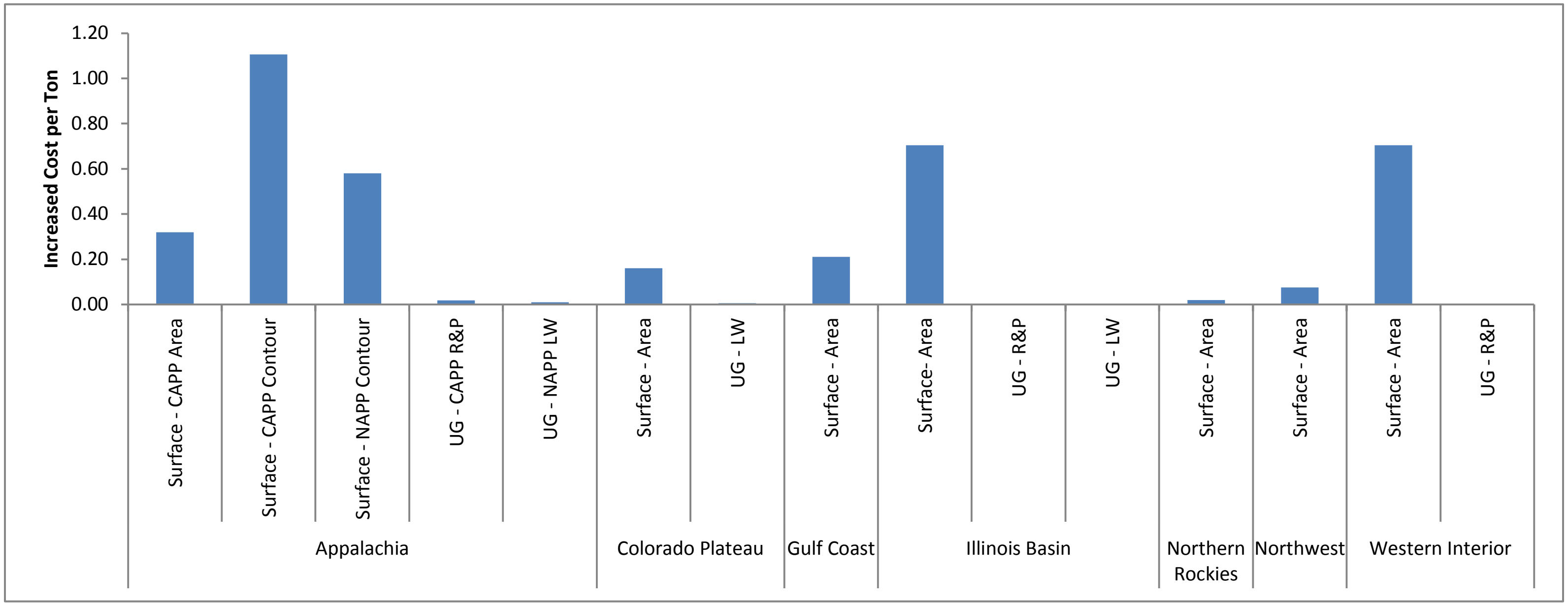


EXHIBIT 8-18. AVERAGE ANNUAL COAL PRODUCTION, 2020-2040

COAL REGION	BASELINE (MILLION TONS)	ALTERNATIVE 3 (MILLION TONS)	CHANGE (MILLION TONS)
Appalachian Basin	236	235	(1.3)
Colorado Plateau	56	56	0
Gulf Coast	54	54	0
Illinois Basin	171	170	(0.3)
North Rocky Mountains/Great Plains	533	532	(0.7)
Northwest	2	2	0
Western Interior	1	1	0
TOTAL	**1,053**	**1,051**	**(2.3)**

EXHIBIT 8-19. INCREASED COST PER TON BY MODEL MINE, ALTERNATIVE 3



Coal Price Impacts

Related to changes in regional coal production, compliance costs, and coal market behavior, Exhibit 8-20 presents the estimated changes in coal prices under Alternative 3 for selected coal regions. The price projections presented in the exhibit suggest that regional coal prices will increase by 0.2 to 2.5 percent under Alternative 3. The increases are most significant in Central Appalachia.

EXHIBIT 8-20. COAL PRICE IMPACTS OF ALTERNATIVE 3 ($/TON)

REGION	2015 BASELINE	2015 ALT. 3	2020 BASELINE	2020 ALT. 3	2030 BASELINE	2030 ALT. 3	2040 BASELINE	2040 ALT. 3
NAPP	56.04	56.04	58.26	58.41	63.03	63.18	69.98	70.12
CAPP	64.00	64.00	67.34	69.02	70.43	72.11	74.27	75.94
ILLB	42.48	42.48	44.75	45.00	46.15	46.41	47.72	47.97
PRB	14.19	14.19	16.02	16.06	17.33	17.37	19.57	19.62
RCK	36.24	36.24	38.50	38.60	38.95	39.05	39.60	39.70

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin
PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.

Market Welfare Effects

Exhibit 8-21 presents the estimated change in market welfare, by year and in aggregate, for Alternative 3 over the 2020-2040 period. Similar to the Proposed Rule, market welfare losses for Alternative 3 largely reflect regulatory compliance costs and a transportation cost savings. This decrease in transportation costs suggests that under Alternative 3, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers.

EXHIBIT 8-21. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS OF ALTERNATIVE 3, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$45.4	$0.01	$45.4
2021	$50.9	$0.01	$50.9
2022	$34.7	$0.01	$34.7
2023	$40.2	$0.01	$40.2
2024	$42.3	$0.01	$42.3
2025	$37.1	$0.01	$37.2
2026	$36.1	$0.01	$36.1
2027	$32.1	$0.01	$32.1
2028	$30.9	$0.01	$30.9
2029	$35.9	$0.01	$35.9
2030	$28.3	$0.01	$28.3
2031	$28.6	$0.01	$28.6
2032	$28.9	$0.01	$28.9
2033	$23.8	$0.01	$23.8
2034	$22.1	$0.00	$22.1
2035	$21.2	$0.00	$21.2
2036	$19.5	$0.00	$19.5
2037	$18.7	$0.00	$18.7
2038	$18.1	$0.00	$18.1
2039	$16.4	$0.00	$16.4
2040	$14.6	$0.00	$14.6
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$57.7**	**$0.01**	**$57.8**

DISTRIBUTIONAL EFFECTS

We estimate the changes in employment that are expected under Alternative 3, relative to the baseline. As shown in Exhibit 8-22A, production-related annual impacts to employment are expected to range from a reduction in demand for 660 FTEs to a reduction of 78 across all regions, with an average decrease in annual demand of 360 FTEs. Across all regions compliance-related employment effects are expected to range from an increase of 310 to 390 FTEs with an average annual increase of 370. Exhibit 8-22B shows the production-related and compliance-related effects as a line graph from 2020 to 2040.

EXHIBIT 8-22A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT ALTERNATIVE 3, 2020-2040, EMPLOYMENT DEMAND: (FTE)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE-RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(100)	(210)	(310)	190
	Range in any year:[2]	(190) - (28)	(360) - (48)	(540) - (76)	160 - 200
Colorado Plateau	Average over 21 years:	0	0	0	19
	Range in any year:	0 - 0	(1) - 0	(1) - 0	16 - 20
Gulf Coast	Average over 21 years:	(1)	0	(1)	42
	Range in any year:	(4) - 0	0 - 0	(4) - 0	42 - 42
Illinois Basin	Average over 21 years:	(6)	(25)	(31)	79
	Range in any year:	(22) - 0	(81) - (2)	(100) - (2)	62 - 91
Northern Rocky Mountains and Great Plains	Average over 21 years:	(22)	0	(22)	33
	Range in any year:	(66) - 0	0 – 0	(66) - 0	29 - 35
Northwest	Average over 21 years:	0	0	0	1
	Range in any year:	0 - 0	0 – 0	0 - 0	1 - 1
Western Interior	Average over 21 years:	0	0	0	3
	Range in any year:	0 - 0	0 - 0	0 - 0	3 - 3
U.S. TOTAL	**Average over 21 years:**	**(130)**	**(230)**	**(360)**	**370**
	Range in any year:	**(260) - (28)**	**(400) - (50)**	**(660) - (78)**	**310 - 390**

[1] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020-2040).

[2] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.

[3] "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.

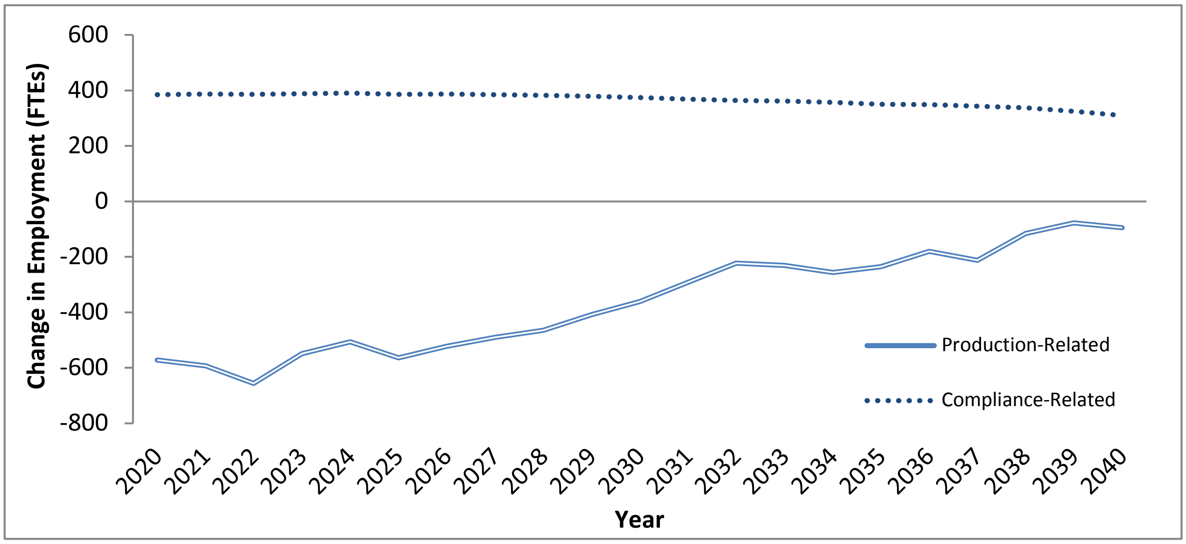
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.

[5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.

[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.

[7] "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 8-22B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 3 COMPARED TO BASELINE, FTES, 2020 TO 2040



Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of Alternative 3. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is not produced because of changes associated with Alternative 3. This volume also becomes smaller over time given that the industry is getting smaller over time. "Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of Alternative 3 follow the pattern of overall forecast coal production. As shown, both the compliance-related and the production-related impacts of the Alternative are reduced over time. However, the slopes of these curves are not the same.

ENVIRONMENT AND HUMAN HEALTH

Exhibit 8-7 summarizes the categories of benefits and costs that are expected to result from Alternative 3 over the time frame of the analysis. Note that the categories are not mutually exclusive but rather complementary in several respects. For example, improved water quality will benefit biological resources, recreation and potentially human health. Exhibits 8-23A through C present the quantified impacts of Alternative 3, stream impacts, forest acre impacts, and air quality impacts.

EXHIBIT 8-23A. QUANTIFIED IMPACTS UNDER ALTERNATIVE 3 BY REGION: STREAM IMPACTS, AVERAGE ANNUAL STREAM MILES

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	173	1	0	1
Colorado Plateau	6	0	0	4
Gulf Coast	36	0	0	7
Illinois Basin	51	0	0	11
Northern Rocky Mountains and Great Plains	22	0	0	6
Northwest	2	0	0	0
Western Interior	2	0	0	0
Total	**292**	**1**	**0**	**29**

EXHIBIT 8-23B. QUANTIFIED IMPACTS UNDER ALTERNATIVE 3 BY REGION: FOREST AREA IMPACTS, AVERAGE ANNUAL FOREST ACRES

COAL REGION	IMPROVED ACRES	PRESERVED ACRES
Appalachian Basin	1,372	30
Colorado Plateau	431	0
Gulf Coast	483	0
Illinois Basin	377	1
Northern Rocky Mountains and Great Plains	105	0
Northwest	1	0
Western Interior	67	0
Total	**2,836**	**31**

EXHIBIT 8-23C. QUANTIFIED IMPACTS UNDER ALTERNATIVE 3 BY REGION: AVERAGE ANNUAL CHANGES IN MEHTANE EMISSIONS (MMCF)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	(28)	(274)	(302)
Colorado Plateau	0	(1)	(1)
Gulf Coast	0	0	0
Illinois Basin	(4)	(75)	(79)
Northern Rocky Mountains and Great Plains	(18)	0	(18)
Northwest	0	0	0
Western Interior	0	0	0
Total	**(50)**	**(350)**	**(400)**
Note: Totals may not sum due to rounding. Negative numbers indicate a decrease of emissions and positive numbers indicate an increase of emissions.			

8.4 ALTERNATIVE 4

Alternative 4 would allow mining in or through intermittent and perennial streams, but only if the hydrologic form and ecological function of those streams can be restored. No restriction would be placed on mining in or through ephemeral streams. This Alternative would prohibit placement of excess spoil or coal mine waste in intermittent or perennial streams unless long-term adverse impacts are offset through fish and wildlife enhancement. No restriction would be placed on placement of excess spoil or coal waste in ephemeral streams.

Exceptions to approximate original contour restoration requirements would be allowed only if they do not result in damage to natural watercourses on or off the permit area. This alternative would define the term "material damage to the hydrologic balance outside the permit area" as any quantifiable adverse impact from surface or underground mining operations that would preclude any designated use of the affected stream segment.

The following sections detail the potential effects of the Proposed Rule under this Alternative.

COMPLIANCE COSTS

Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculated the total compliance cost effects for Alternative 4. These results, annualized, are provided in Exhibit 8-24.

EXHIBIT 8-24. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE4, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE	TOTAL
Appalachia	Surface	$28,300,000	$2,730,000	$2,780	$31,000,000
	UG	$1,670,000	$4,970,000	$7,160	$6,650,000
Colorado Plateau	Surface	$4,110,000	$130,000	$1,340	$4,240,000
	UG	$120,000	$80,400	$985	$201,000
Gulf Coast	Surface	$8,710,000	$339,000	$2,600	$9,050,00
Illinois Basin	Surface	$16,200,000	$644,000	$1,500	$16,800,000
	UG	$0	$261,000	$4,950	$266,000
Northern Rocky Mountains and Great Plains	Surface	$7,960,000	$204,000	$24,200	$8,190,000
Northwest	Surface	$113,000	$18,900	$98	$132,000
Western Interior	Surface	$643,000	$26,100	$61	$669,000
	UG	$0	$526	$5	$530
Annualized U.S. Compliance Cost Impacts	Surface	$66,000,000	$4,090,000	$32,600	$70,100,000
	UG	$1,790,000	$5,320,000	$13,100	$7,110,000
	TOTAL	**$67,800,000**	**$9,410,000**	**$45,700**	**$77,300,000**
Note: Totals may not sum due to rounding.					

MARKET WELFARE EFFECTS

Changes in Coal Production

Exhibits 8-25 and 8-26 show the projected change in coal production from 2020 through 2040 under Alternative 4. Under this Alternative, reductions in coal production occur for both surface and underground mining. As shown in Exhibit 8-25, surface mines account for the majority of the decline in production under this alternative. The net reduction in the volume of coal produced is forecast to lessen over the time period for the analysis, consistent with the declining demand for U.S. coal from retiring coal-fired power plants. In aggregate, however, the reduction in coal production under Alternative 4 is slightly more than those in the Proposed Rule. Exhibit 8-26 shows that approximately half this reduction is in the Appalachian Basin. Exhibit 8-27 displays the additional operational costs per ton for each model mine under Alternative 4. In general, the expected change in operational costs per ton are higher for surface mines than they are for underground mines, and the Appalachian Basin is expected to experience the largest change.

EXHIBIT 8-25. ANNUAL CHANGES IN COAL PRODUCTION UNDER ALTERNATIVE 4

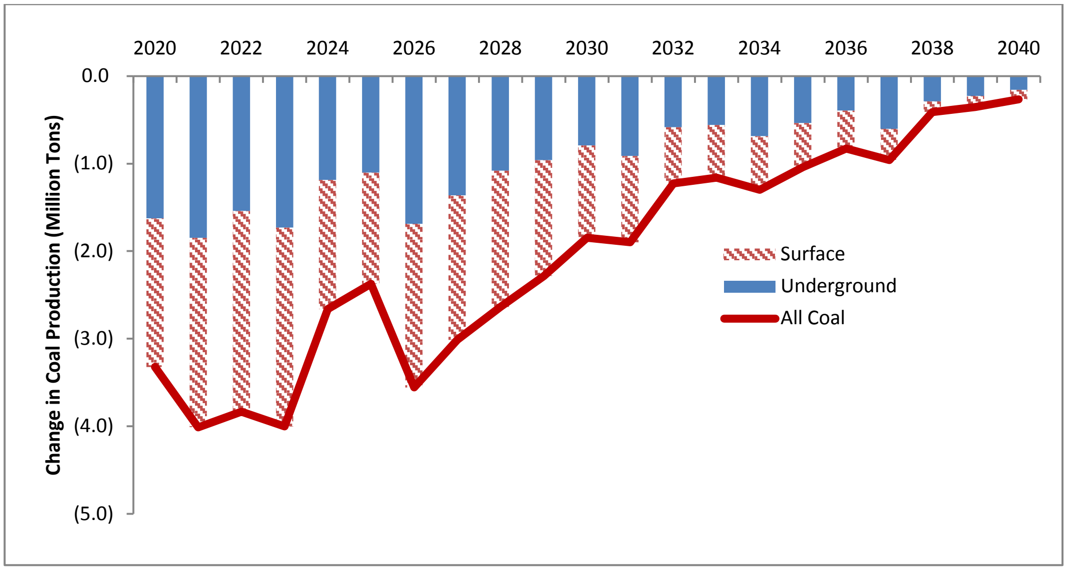
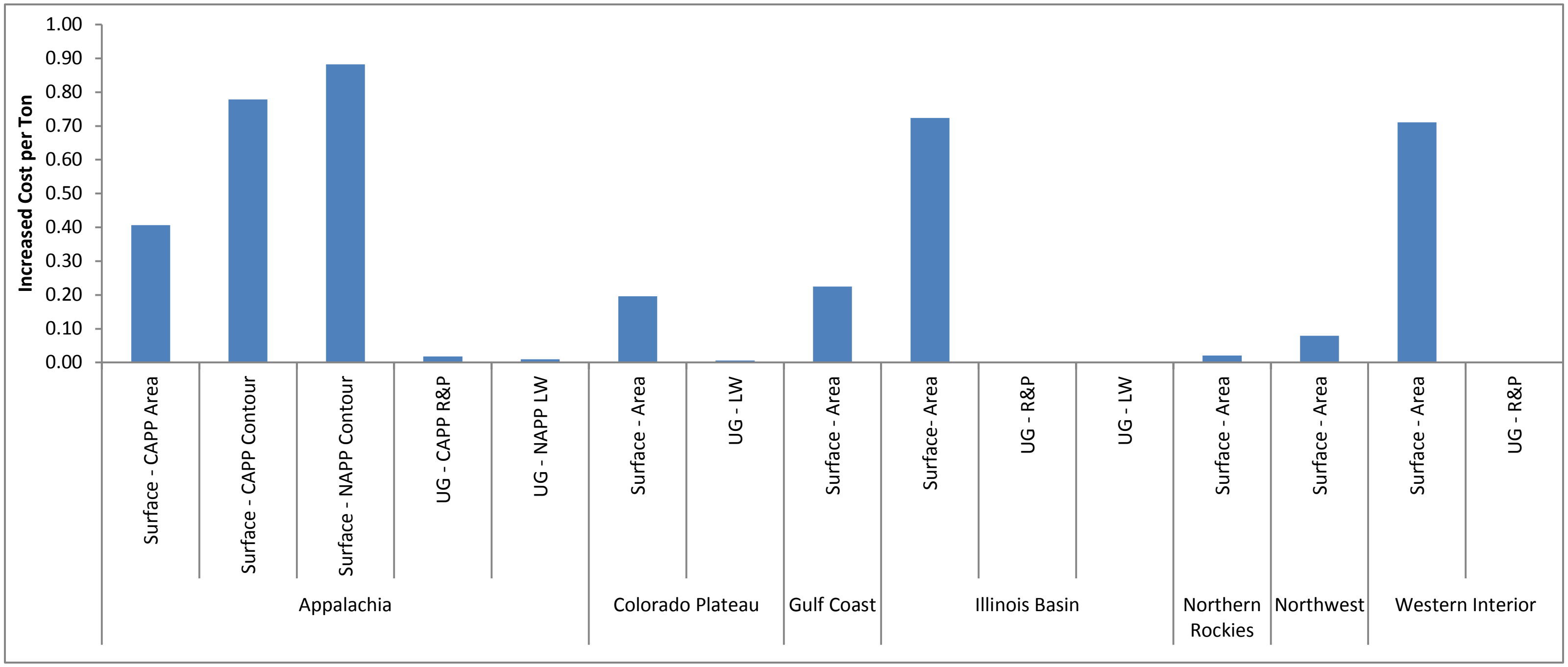


EXHIBIT 8-26. AVERAGE ANNUAL COAL PRODUCTION, 2020-2040

COAL REGION	BASELINE (MILLION TONS)	ALTERNATIVE 4 (MILLION TONS)	CHANGE (MILLION TONS)
Appalachian Basin	236	235	(1.0)
Colorado Plateau	56	56	0
Gulf Coast	54	54	0
Illinois Basin	171	170	(0.3)
North Rocky Mountains/Great Plains	533	532	(0.7)
Northwest	2	2	0
Western Interior	1	1	0
TOTAL	**1,053**	**1,051**	**(2.1)**

EXHIBIT 8-27. INCREASED COST PER TON BY MODEL MINE, ALTERNATIVE 4



Coal Price Impacts

Related to changes in regional coal production, compliance costs, and coal market behavior, Exhibit 8-28 presents the estimated changes in coal prices under Alternative 4 for selected coal regions. The price projections presented in the exhibit suggest that regional coal prices will increase by 0.2 to 1.8 percent under Alternative 4. The increases are most significant in Central Appalachia.

EXHIBIT 8-28. COAL PRICE IMPACTS OF ALTERNATIVE 4 ($/TON)

REGION	2015 BASELINE	2015 ALT. 4	2020 BASELINE	2020 ALT. 4	2030 BASELINE	2030 ALT. 4	2040 BASELINE	2040 ALT. 4
NAPP	56.04	56.04	58.26	58.46	63.03	63.23	69.98	70.18
CAPP	64.00	64.00	67.34	68.55	70.43	71.63	74.27	75.47
ILLB	42.48	42.48	44.75	45.00	46.15	46.42	47.72	47.98
PRB	14.19	14.19	16.02	16.07	17.33	17.38	19.57	19.62
RCK	36.24	36.24	38.50	38.62	38.95	39.07	39.60	39.72

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin

PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.

Market Welfare Effects

Exhibit 8-29 presents the estimated change in market welfare, by year and in aggregate, for Alternative 4 over the 2020-2040 period. Similar to the Proposed Rule, market welfare losses for Alternative 4 largely reflect regulatory compliance costs and a transportation cost savings. This decrease in transportation costs suggests that under Alternative 4, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers.

EXHIBIT 8-29. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS OF ALTERNATIVE 4, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$53.4	$0.01	$53.4
2021	$49.8	$0.01	$49.8
2022	$41.3	$0.01	$41.3
2023	$36.6	$0.01	$36.6
2024	$44.4	$0.01	$44.4
2025	$41.5	$0.01	$41.5
2026	$32.1	$0.01	$32.1
2027	$33.7	$0.01	$33.7
2028	$30.7	$0.01	$30.7
2029	$30.9	$0.01	$30.9
2030	$29.4	$0.01	$29.4
2031	$27.0	$0.01	$27.0
2032	$27.1	$0.01	$27.1
2033	$25.0	$0.01	$25.0
2034	$22.9	$0.00	$22.9
2035	$21.5	$0.00	$21.5
2036	$20.1	$0.00	$20.2
2037	$18.8	$0.00	$18.8
2038	$18.6	$0.00	$18.6
2039	$16.7	$0.00	$16.7
2040	$15.0	$0.00	$15.0
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$58.7**	**$0.01**	**$58.7**

DISTRIBUTIONAL EFFECTS

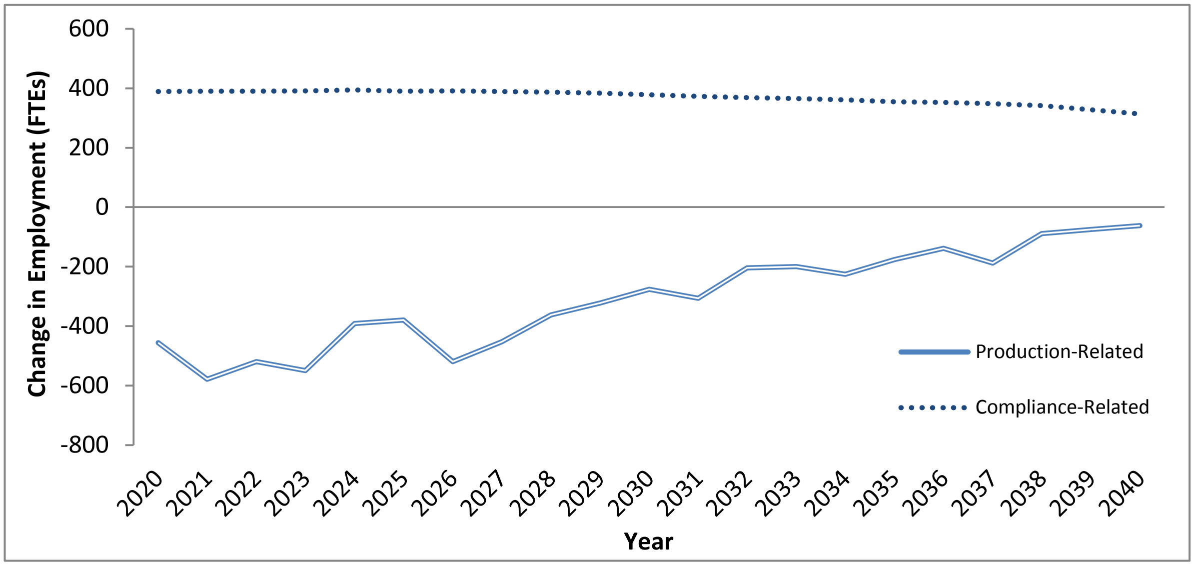
We estimate the changes in employment that are expected under Alternative 4, relative to the baseline. As shown in Exhibit 8-30A, production-related annual impacts to employment are expected to range from a reduction in demand for 580 FTEs to a reduction of 62 across all regions, with an average decrease in annual demand of 310 FTEs. Across all regions, compliance-related employment effects are expected to range from an increase of 310 FTEs to 390, with an average increase of 370. Exhibit 8-30B shows the production-related and compliance-related effects as a line graph from 2020 to 2040.

EXHIBIT 8-30A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 4, 2020-2040, EMPLOYMENT DEMAND: (FTE)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(80)	(170)	(250)	180
	Range in any year:[2]	(140) - (23)	(310) – (38)	(450) - (62)	150 - 190
Colorado Plateau	Average over 21 years:	0	0	0	23
	Range in any year:	0 - 0	0 - 1	0 - 1	19 - 24
Gulf Coast	Average over 21 years:	(1)	0	(1)	45
	Range in any year:	(6) - 0	0 - 0	(6) - 0	44 - 45
Illinois Basin	Average over 21 years:	(6)	(27)	(33)	81
	Range in any year:	(22) - 0	(84) - 0	(110) - (1)	63 - 94
Northern Rocky Mountains and Great Plains	Average over 21 years:	(22)	0	(22)	36
	Range in any year:	(51) – 0	0 – 0	(51) – (1)	32 - 38
Northwest	Average over 21 years:	0	0	0	1
	Range in any year:	0 - 0	0 - 0	0 - 0	1 - 1
Western Interior	Average over 21 years:	0	0	0	3
	Range in any year:	0 - 0	0 - 0	0 - 0	3 - 3
U.S. TOTAL	**Average over 21 years:**	**(110)**	**(200)**	**(310)**	**370**
	Range in any year:	**(210) - (24)**	**(370) - (39)**	**(580) - (62)**	**310 - 390**

[1] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020-2040).
[2] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.
[3] "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
[5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 8-30B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 4 COMPARED TO BASELINE, FTES, 2020 TO 2040



Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of Alternative 4. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is not produced because of changes associated with Alternative 4. This volume also becomes smaller over time given that the industry is getting smaller over time. "Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of Alternative 4 follow the pattern of overall forecast coal production. As shown, both the compliance-related and the production-related impacts of the Alternative are reduced over time. However, the slopes of these curves are not the same.

ENVIRONMENT AND HUMAN HEALTH

Exhibit 8-7 summarizes the categories of benefits and costs that are expected to result from Alternative 4 over the time frame of the analysis. Note that the categories are not mutually exclusive but rather complementary in several respects. For example, improved water quality will benefit biological resources, recreation and potentially human health. Exhibits 8-31A through C present the quantified impacts of Alternative 4, stream impacts, forest acre impacts, and air quality impacts.

EXHIBIT 8-31A. QUANTIFIED IMPACTS UNDER ALTERNATIVE 4 BY REGION: STREAM IMPACTS, AVERAGE ANNUAL STREAM MILES

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	174	1	4	1
Colorado Plateau	6	0	0	4
Gulf Coast	36	0	0	7
Illinois Basin	51	0	0	11
Northern Rocky Mountains and Great Plains	22	0	0	6
Northwest	2	0	0	0
Western Interior	2	0	0	0
Total	**293**	**1**	**4**	**29**

EXHIBIT 8-31B. QUANTIFIED IMPACTS UNDER ALTERNATIVE 4 BY REGION: FOREST AREA IMPACTS, AVERAGE ANNUAL FOREST ACRES

COAL REGION	IMPROVED ACRES	PRESERVED ACRES
Appalachian Basin	1,344	24
Colorado Plateau	431	0
Gulf Coast	483	0
Illinois Basin	377	1
Northern Rocky Mountains and Great Plains	105	0
Northwest	1	0
Western Interior	67	0
Total	**2,808**	**25**

EXHIBIT 8-31C. QUANTIFIED IMPACTS UNDER ALTERNATIVE 4 BY REGION: AVERAGE ANNUAL CHANGES IN MEHTANE EMISSIONS (MMCF)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	(22)	(228)	(250)
Colorado Plateau	0	1	1
Gulf Coast*	(1)	0	(1)
Illinois Basin	(4)	(80)	(84)
Northern Rocky Mountains and Great Plains	(18)	(1)	(19)
Northwest*	0	0	0
Western Interior	0	0	0
Total	**(44)**	**(309)**	**(353)**
Note: Totals may not sum due to rounding. Negative numbers indicate a decrease of emissions and positive numbers indicate an increase of emissions.			

8.5 ALTERNATIVE 5

Alternative 5 would apply only to those mining operations that would produce excess spoil and propose to dispose of that spoil outside of the mine pit, or that would propose to place coal mine waste in intermittent or perennial streams. If one or the other of these circumstances apply then under Alternative 5 the applicant could mine in or through intermittent and perennial streams, but only if the hydrologic form and ecological function of those streams can be restored.

If neither of these circumstances apply, the mining operation would be conducted under the existing rules of the Baseline, including those involving mining in or through streams.

In either instance, no restriction would be placed on mining in or through ephemeral streams. No restriction would be placed on placement of excess spoil or coal waste in ephemeral streams.

In either instance, this alternative would not include a definition of material damage to the hydrologic balance or require corrective action thresholds. The following sections detail the potential effects of the Proposed Rule under this Alternative.

COMPLIANCE COSTS

Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculated the total compliance cost effects for Alternative 5. These results, annualized, are provided in Exhibit 8-32.

EXHIBIT 8-32. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 5, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE	TOTAL
Appalachia	Surface	$20,000,000	$2,730,000	$2,780	$22,800,000
	UG	$1,670,000	$4,970,000	$7,160	$6,650,000
Colorado Plateau	Surface	$0	$0	$0	$0
	UG	$0	$0	$0	$0
Gulf Coast	Surface	$0	$0	$0	$0
Illinois Basin	Surface	$0	$0	$0	$0
	UG	$0	$0	$0	$0
Northern Rocky Mountains and Great Plains	Surface	$0	$0	$0	$0
Northwest	Surface	$0	$0	$0	$0
Western Interior	Surface	$0	$0	$0	$0
	UG	$0	$0	$0	$0
Annualized U.S. Compliance Cost Impacts	Surface	$20,000,000	$2,730,000	$2,780	$22,800,000
	UG	$1,670,000	$4,970,000	$7,160	$6,650,000
	TOTAL	**$21,700,000**	**$7,710,000**	**$9,930**	**$29,400,000**
Note: Totals may not sum due to rounding.					

MARKET WELFARE EFFECTS

Changes in Coal Production

Exhibits 8-33 and 8-34 show the projected change in coal production from 2020 through 2040 under Alternative 5. Under this Alternative, reductions in coal production occur for both surface and underground mining. As shown in Exhibit 8-33, surface mines account for the majority of the decline in production under this alternative. The net reduction in the volume of coal produced is forecast to lessen over the time period for the analysis, consistent with the declining demand for U.S. coal from retiring coal-fired power plants. In aggregate, however, the reduction in coal production under Alternative 5 is approximately the same as those in the Proposed Rule. Exhibit 8-34 shows that approximately half this reduction is in the Appalachian Basin. Exhibit 8-35 displays the additional operational costs per ton for each model mine under Alternative 5. The expected changes in operational costs per ton are higher for surface mines than they are for underground mines, and the Appalachian Basin is the only region expected to experience a change in these costs under this Alternative.

EXHIBIT 8-33. ANNUAL CHANGES IN COAL PRODUCTION UNDER ALTERNATIVE 5

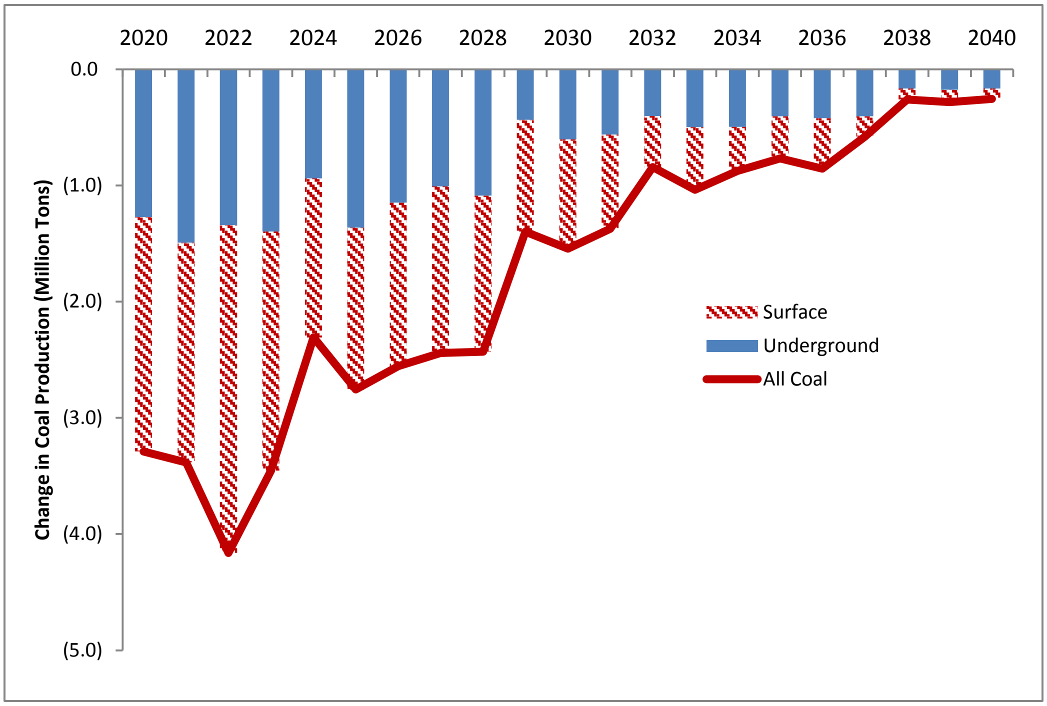
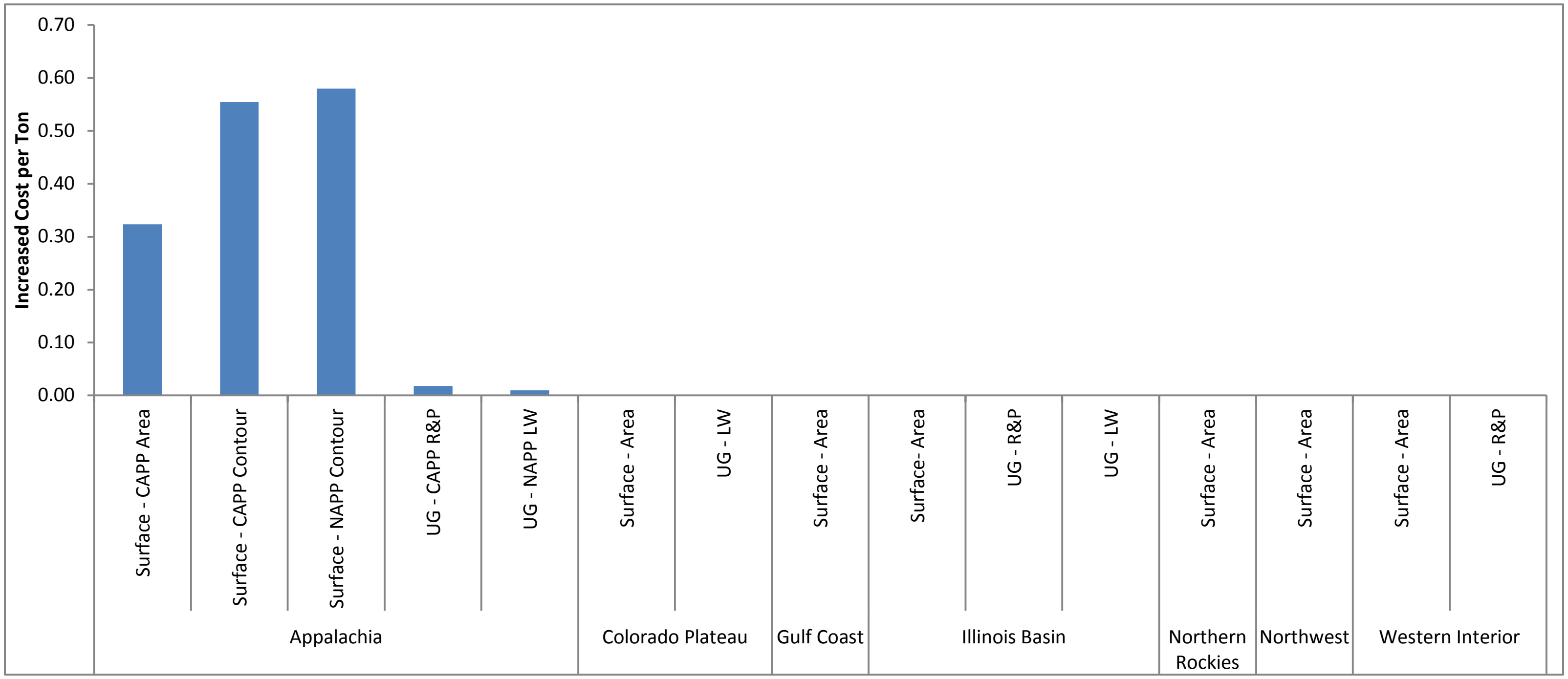


EXHIBIT 8-34. ANNUAL COAL PRODUCTION, 2020-2040

COAL REGION	BASELINE (MILLION TONS)	ALTERNATIVE 5 (MILLION TONS)	CHANGE (MILLION TONS)
Appalachian Basin	236	235	(0.9)
Colorado Plateau	56	56	0
Gulf Coast	54	54	0
Illinois Basin	171	171	(0.2)
North Rocky Mountains/Great Plains	533	532	(0.7)
Northwest	2	2	0
Western Interior	1	1	0
TOTAL	**1,053**	**1,051**	**(1.8)**

EXHIBIT 8-35. INCREASED COST PER TON BY MODEL MINE, ALTERNATIVE 5



Coal Price Impacts

Related to changes in regional coal production, compliance costs, and coal market behavior, Exhibit 8-36 presents the estimated changes in coal prices under Alternative 5 for selected coal regions. The price projections presented in the exhibit suggest that regional coal prices will increase by -0.1 to 1.3 percent under Alternative 5. The increases are largest in Central Appalachia.

EXHIBIT 8-36. COAL PRICE IMPACTS OF ALTERNATIVE 5 ($/TON)

REGION	2015 BASELINE	2015 ALT. 5	2020 BASELINE	2020 ALT. 5	2030 BASELINE	2030 ALT. 5	2040 BASELINE	2040 ALT. 5
NAPP	56.04	56.04	58.26	58.41	63.03	63.18	69.98	70.12
CAPP	64.00	64.00	67.34	68.22	70.43	71.31	74.27	75.14
ILLB	42.48	42.48	44.75	44.75	46.15	46.15	47.72	47.72
PRB	14.19	14.19	16.02	16.00	17.33	17.32	19.57	19.56
RCK	36.24	36.24	38.50	38.50	38.95	38.95	39.60	39.60

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin
PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.

Market Welfare Effects

Exhibit 8-37 presents the estimated change in market welfare, by year and in aggregate, for Alternative 5 over the 2020-2040 period. Similar to the Proposed Rule, market welfare losses for Alternative 5 largely reflect regulatory compliance costs and a transportation cost savings. This decrease in transportation costs suggests that under Alternative 5, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers.

EXHIBIT 8-37. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS OF ALTERNATIVE 5, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$2.7	$0.01	$2.7
2021	$9.5	$0.01	$9.5
2022	($5.7)	$0.01	($5.7)
2023	($0.1)	$0.01	($0.1)
2024	$12.0	$0.01	$12.0
2025	$6.9	$0.00	$6.9
2026	$8.6	$0.00	$8.6
2027	$5.8	$0.00	$5.8
2028	$5.5	$0.00	$5.5
2029	$8.9	$0.00	$8.9
2030	$7.5	$0.00	$7.5
2031	$7.0	$0.00	$7.0
2032	$9.4	$0.00	$9.4
2033	$7.5	$0.00	$7.5
2034	$8.0	$0.00	$8.0
2035	$7.6	$0.00	$7.6
2036	$6.6	$0.00	$6.6
2037	$6.8	$0.00	$6.8
2038	$6.9	$0.00	$6.9
2039	$5.9	$0.00	$5.9
2040	$5.4	$0.00	$5.4
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$12.2**	**$0.01**	**$12.2**

DISTRIBUTIONAL EFFECTS

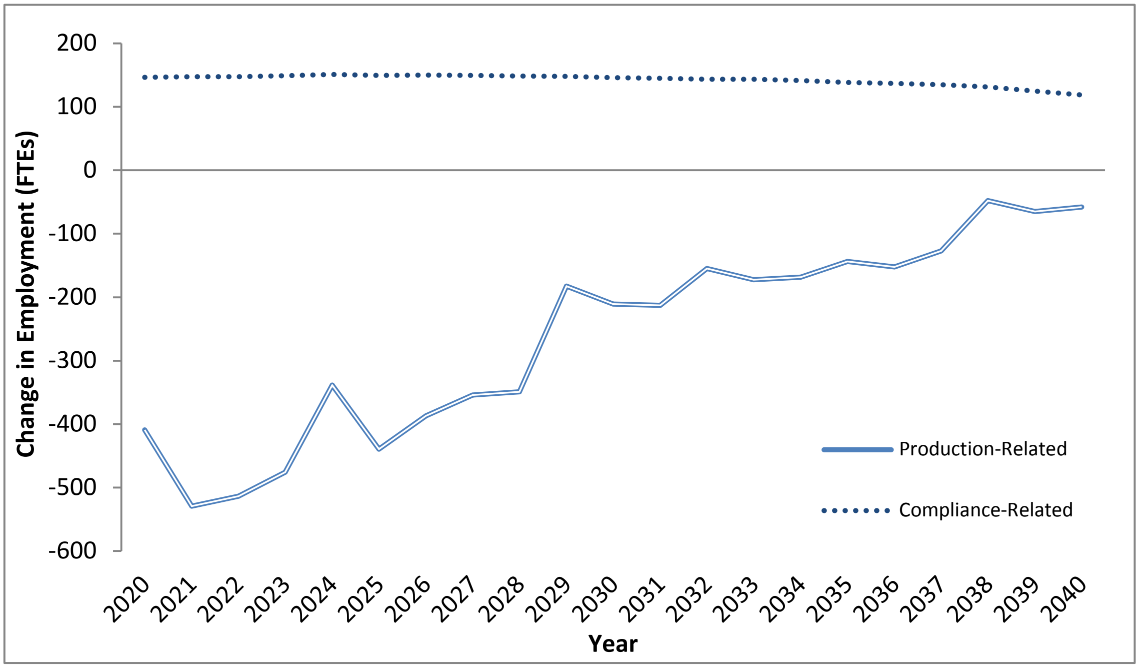
We estimate the changes in employment that are expected under Alternative 5, relative to the baseline. As shown in Exhibit 8-38A, production-related annual impacts to employment are expected to range from a reduction in demand for 530 FTEs to a reduction of 48 across all regions, with an average reduction in annual demand of 260 FTEs. Across all regions compliance-related employment effects are expected to range from an increase of 120 to 150 FTEs with an average annual increase of 140. Exhibit 8-38B shows the production-related and compliance-related effects as a line graph from 2020 to 2040.

EXHIBIT 8-38A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 5, 2020-2040, EMPLOYMENT DEMAND: (FTE)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(69)	(160)	(220)	140
	Range in any year:[2]	(140) - (11)	(330) – (29)	(470) - (41)	120 - 150
Colorado Plateau	Average over 21 years:	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 1	0 - 0
Gulf Coast	Average over 21 years:	0	0	0	0
	Range in any year:	(1) – 2	0 - 0	(1) - 2	0 - 0
Illinois Basin	Average over 21 years:	(3)	(13)	(16)	0
	Range in any year:	(13) - 0	(48) - (1)	(60) - (1)	0 - 0
Northern Rocky Mountains and Great Plains	Average over 21 years:	(22)	0	(22)	0
	Range in any year:	(70) – 0	0 – 0	(70) – 0	0 - 0
Northwest	Average over 21 years:	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0
Western Interior	Average over 21 years:	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0
U.S. TOTAL	**Average over 21 years:**	**(93)**	**(170)**	**(260)**	**140**
	Range in any year:	**(210) - (14)**	**(350) - (34)**	**(530) - (48)**	**120 - 150**

[1] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020-2040).
[2] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.
[3] "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
[5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 8-38B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 5 COMPARED TO BASELINE, FTES, 2020 TO 2040



Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of Alternative 5. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is not produced because of changes associated with Alternative 5. This volume also becomes smaller over time given that the industry is getting smaller over time. "Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of Alternative 5 follow the pattern of overall forecast coal production. As shown, both the compliance-related and the production-related impacts of the Alternative are reduced over time. However, the slopes of these curves are not the same.

ENVIRONMENT AND HUMAN HEALTH

Exhibit 8-7 summarizes the categories of benefits and costs that are expected to result from Alternative 5 over the time frame of the analysis. Note that the categories are not mutually exclusive but rather complementary in several respects. For example, improved water quality will benefit biological resources, recreation and potentially human health. Exhibits 8-39A through C present the quantified impacts of Alternative 5, stream impacts, forest acre impacts, and air quality impacts.

EXHIBIT 8-39A. QUANTIFIED IMPACTS UNDER ALTERNATIVE 5 BY REGION: STREAM IMPACTS, AVERAGE ANNUAL STREAM MILES

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	174	1	4	1
Colorado Plateau	0	0	0	0
Gulf Coast	0	0	0	0
Illinois Basin	0	0	0	0
Northern Rocky Mountains and Great Plains	0	0	0	0
Northwest	0	0	0	0
Western Interior	0	0	0	0
Total	**174**	**1**	**4**	**1**

EXHIBIT 8-39B. QUANTIFIED IMPACTS UNDER ALTERNATIVE 5 BY REGION: FOREST AREA IMPACTS, AVERAGE ANNUAL FOREST ACRES

COAL REGION	IMPROVED ACRES	PRESERVED ACRES
Appalachian Basin	1,346	20
Colorado Plateau	0	0
Gulf Coast	0	0
Illinois Basin	0	1
Northern Rocky Mountains and Great Plains	0	0
Northwest	0	0
Western Interior	0	0
Total	**1,346**	**21**

EXHIBIT 8-39C. QUANTIFIED IMPACTS UNDER ALTERNATIVE 5 BY REGION: AVERAGE ANNUAL CHANGES IN MEHTANE EMISSIONS (MMCF)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	(19)	(205)	(244)
Colorado Plateau	0	0	1
Gulf Coast	0	0	0
Illinois Basin	(2)	(39)	(41)
Northern Rocky Mountains and Great Plains	(18)	(1)	(19)
Northwest*	0	0	0
Western Interior	0	0	0
Total	**(38)**	**(245)**	**(283)**

Note: Totals may not sum due to rounding. Negative numbers indicate a decrease of emissions and positive numbers indicate an increase of emissions.

8.6 ALTERNATIVE 6

Alternative 6 would apply only to surface disturbances in or within 100 feet of a perennial or intermittent stream. This alternative would prohibit mining activities in or within 100 feet of intermittent or perennial streams unless the applicant demonstrates to the satisfaction of the regulatory authority that:

(1) The ecological function of the stream would be protected or restored;

(2) Placement of excess spoil or coal mine waste in or near the stream would not result in the creation of toxic mine drainage;

(3) Long-term adverse impacts (including impacts within the footprint of any fill) to the environmental resources of the stream would be offset in the same or adjacent watershed through fish and wildlife enhancement commensurate with the adverse impacts; and

(4) Other proposed mining activities within the stream buffer, but not within the stream itself would not adversely affect the water quantity and quality or other environmental resources of the stream. When disturbances within 100 feet of a perennial or intermittent stream did occur, this alternative would require establishment of an appropriately-vegetated 100-foot riparian corridor along the entire reach of all streams (including ephemeral streams) within the permit area after mining is completed.

All mining operations outside 100 feet of a perennial or intermittent stream would proceed under the existing requirements of the Baseline.

The following sections detail the potential effects of the Proposed Rule under this Alternative.

COMPLIANCE COSTS

Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculated the total compliance cost effects for Alternative 6. These results, annualized, are provided in Exhibit 8-40.

EXHIBIT 8-40. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 6, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE	TOTAL
Appalachia	Surface	$6,090,000	$1,280,000	$2,790	$7,370,000
	UG	$0	$4,890,000	$7,170	$4,890,000
Colorado Plateau	Surface	$433,000	$42,000	$1,340	$476,000
	UG	$0	$74,800	$985	$75,800
Gulf Coast	Surface	$737,000	$113,000	$2,600	$853,000
Illinois Basin	Surface	$13,500,000	$216,000	$1,500	$13,700,000
	UG	$0	$249,000	$5,000	$254,000
Northern Rocky Mountains and Great Plains	Surface	$762,000	$66,000	$24,200	$852,000
Northwest	Surface	$32,000	$11,300	$98	$43,700
Western Interior	Surface	$544,000	$8,720	$61	$553,000
	UG	$0	$495	$5	$500
Annualized U.S. Compliance Cost Impacts	Surface	$22,100,000	$1,740,00	$32,600	$23,800,000
	UG	$0	$5,210,000	$13,400	$5,220,000
	TOTAL	**$22,100,000**	**$6,950,000**	**$45,700**	**$29,070,000**
Note: Totals may not sum due to rounding.					

MARKET WELFARE EFFECTS

Changes in Coal Production

Exhibits 8-41 and 8-42 show the projected change in coal production from 2020 through 2040 under Alternative 6. Under this Alternative, reductions in coal production occur for both surface and underground mining. As shown in Exhibit 8-41, surface mines account for the majority of the decline in production under this Alternative. The net reduction in the volume of coal produced is forecast to lessen over the time period for the analysis, consistent with the declining demand for U.S. coal from retiring coal-fired power plants. In aggregate, however, the reduction in coal production under Alternative 6 is less than those in the Proposed Rule. Exhibit 8-42 shows that more than half this reduction is in the Northern Rocky Mountains and Great Plains Region. Exhibit 8-43 displays the additional operational costs per ton for each model mine under Alternative 6. In general, the expected change in operational costs per ton are higher for surface mines than they are for underground mines, and the Illinois Basin and Western Interior are expected to experience the largest changes.

EXHIBIT 8-41. ANNUAL CHANGES IN COAL PRODUCTION UNDER ALTERNATIVE 6

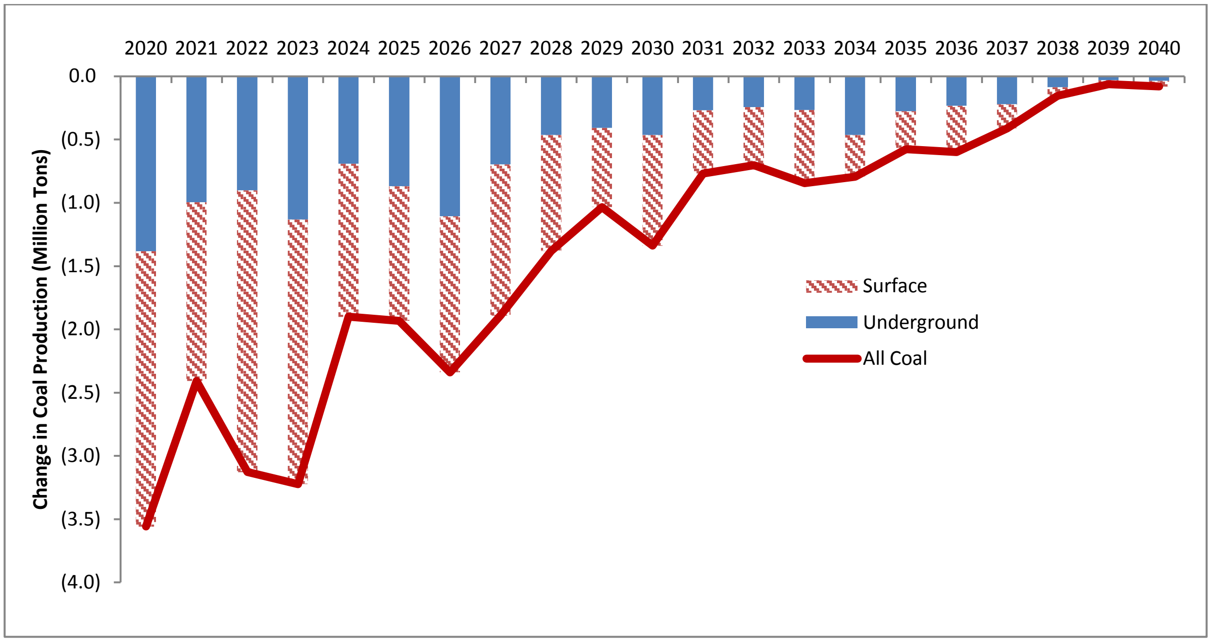
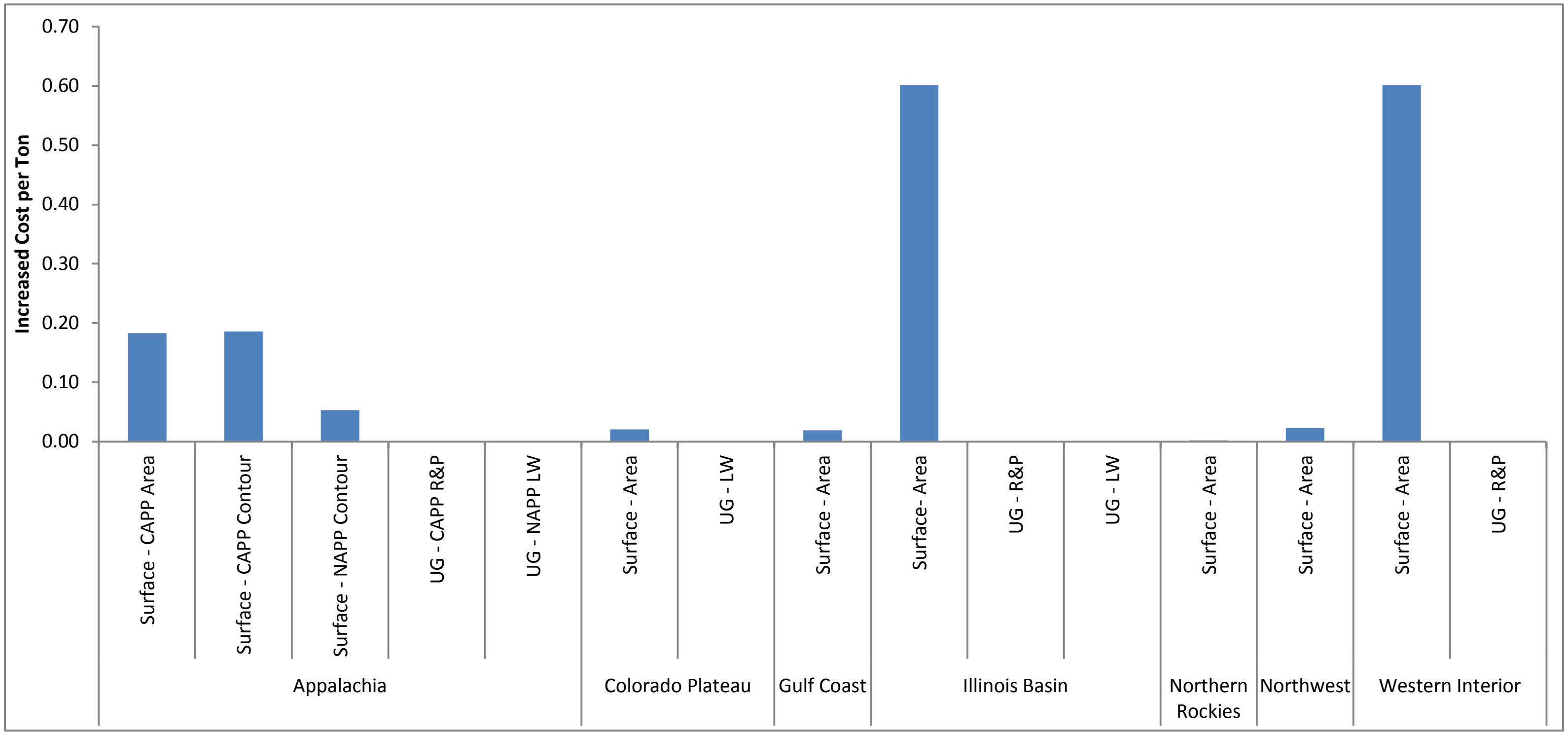


EXHIBIT 8-42. ANNUAL COAL PRODUCTION, 2020-2040

COAL REGION	BASELINE (MILLION TONS)	ALTERNATIVE 6 (MILLION TONS)	CHANGE (MILLION TONS)
Appalachian Basin	236	235	(0.5)
Colorado Plateau	56	56	0
Gulf Coast	54	54	0
Illinois Basin	171	170	(0.3)
North Rocky Mountains/ Great Plains	533	532	(0.7)
Northwest	2	2	0
Western Interior	1	1	0
TOTAL	**1,053**	**1,052**	**(1.4)**

EXHIBIT 8-43. INCREASED COST PER TON BY MODEL MINE, ALTERNATIVE 6



Coal Price Impacts

Related to changes in regional coal production, compliance costs, and coal market behavior, Exhibit 8-44 presents the estimated changes in coal prices under Alternative 6 for selected coal regions. The price projections presented in the exhibit suggest that regional coal prices will increase by -0.1 to 0.5 percent under Alternative 6. The increases are most significant in Central Appalachia.

EXHIBIT 8-44. COAL PRICE IMPACTS OF ALTERNATIVE 6 ($/TON)

REGION	2015 BASELINE	2015 ALT. 6	2020 BASELINE	2020 ALT. 6	2030 BASELINE	2030 ALT. 6	2040 BASELINE	2040 ALT. 6
NAPP	56.04	56.04	58.26	58.28	63.03	63.05	69.98	70.00
CAPP	64.00	64.00	67.34	67.66	70.43	70.74	74.27	74.58
ILLB	42.48	42.48	44.75	44.96	46.15	46.37	47.72	47.94
PRB	14.19	14.19	16.02	16.01	17.33	17.32	19.57	19.56
RCK	36.24	36.24	38.50	38.52	38.95	38.97	39.60	39.62

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin
PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.

Market Welfare Effects

Exhibit 8-45 presents the estimated change in market welfare, by year and in aggregate, for Alternative 6 over the 2020-2040 period. Similar to the Proposed Rule, market welfare losses for Alternative 6 largely reflect regulatory compliance costs and a transportation cost savings. This decrease in transportation costs suggests that under Alternative 6, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers.

EXHIBIT 8-45. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS OF ALTERNATIVE 6, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	($0.1)	$0.01	($0.1)
2021	$0.4	$0.01	$0.4
2022	($0.4)	$0.01	($0.4)
2023	$0.5	$0.01	$0.5
2024	$10.7	$0.01	$10.7
2025	$4.8	$0.01	$4.8
2026	$6.0	$0.01	$6.0
2027	$3.2	$0.01	$3.3
2028	$5.4	$0.01	$5.4
2029	$8.8	$0.01	$8.8
2030	$6.7	$0.01	$6.7
2031	$7.7	$0.01	$7.7
2032	$8.3	$0.01	$8.3
2033	$6.6	$0.01	$6.6
2034	$5.4	$0.00	$5.4
2035	$6.6	$0.00	$6.6
2036	$5.7	$0.00	$5.7
2037	$5.6	$0.00	$5.6
2038	$6.6	$0.00	$6.6
2039	$5.7	$0.00	$5.7
2040	$5.0	$0.00	$5.0
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$10.1**	**$0.01**	**$10.1**

DISTRIBUTIONAL EFFECTS

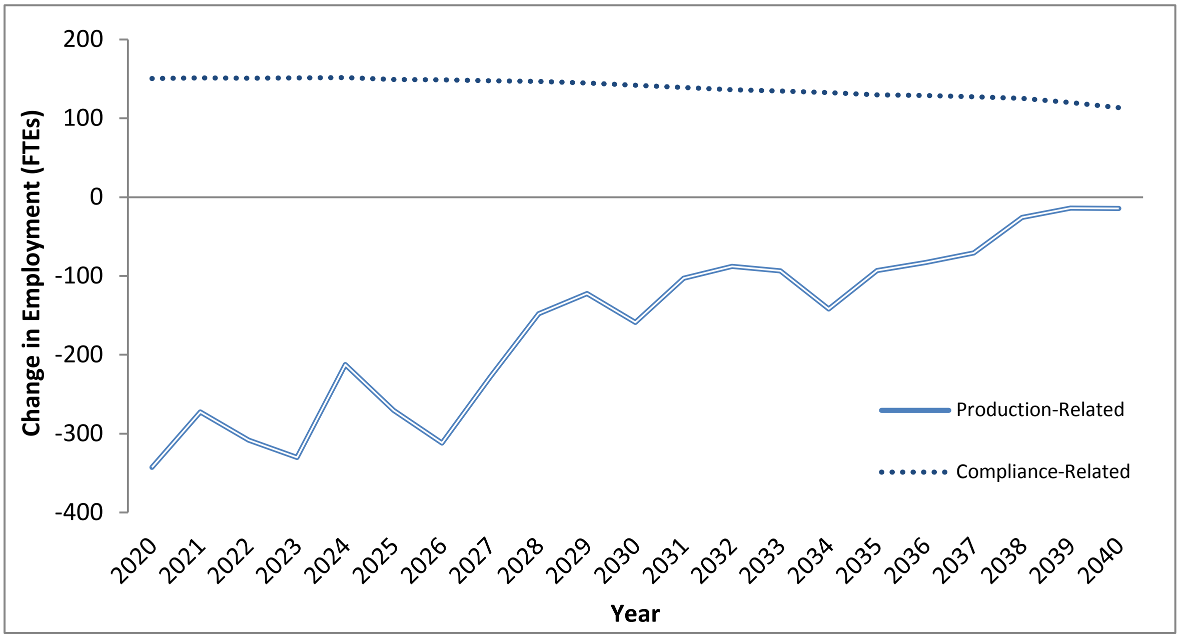
We estimate the changes in employment that are expected under Alternative 6, relative to the baseline. As shown in Exhibit 8-46A, production-related annual impacts to employment are expected to range from a reduction in demand for 340 FTEs to a reduction of 14 across all regions, with an average reduction in annual demand of 160 FTEs. Across all regions, compliance-related employment effects are expected to range from an increase of 110 to 150 FTEs, with an average annual increase of 140. Exhibit 8-46B shows the production-related and compliance-related effects as a line graph from 2020 to 2040.

EXHIBIT 8-46A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 6, 2020-2040, EMPLOYMENT DEMAND: (FTE)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE- RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(35)	(80)	(120)	59
	Range in any year:[2]	(67) – (6)	(160) - (6)	(230) - (13)	49 - 63
Colorado Plateau	Average over 21 years:	0	0	0	3
	Range in any year:	0 - 0	0 - 0	(1) - 0	2 - 3
Gulf Coast	Average over 21 years:	1	0	1	4
	Range in any year:	0 - 4	0 - 0	0 - 4	4 - 4
Illinois Basin	Average over 21 years:	(5)	(22)	(28)	66
	Range in any year:	(27) - 0	(100) - 1	(130) - 1	52 - 76
Northern Rocky Mountains and Great Plains	Average over 21 years:	(21)	0	(21)	4
	Range in any year:	(60) – 0	0 – 0	(60) – 0	3 - 4
Northwest	Average over 21 years:	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0
Western Interior	Average over 21 years:	0	0	0	3
	Range in any year:	0 - 0	0 - 0	0 - 0	3 – 3
U.S. TOTAL	**Average over 21 years:**	**(61)**	**(100)**	**(160)**	**140**
	Range in any year:	**(130) - (6)**	**(210) - (7)**	**(340) - (14)**	**110 - 150**

[1] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020-2040).
[2] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.
[3] "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period. [5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.
[8] The range of "Total Effects on Employment" represents the minimum and maximum effect in any year in the study period when impacts on production as well as compliance-related employment are combined. Because the minimum and maximum effects of the Alternative on production and compliance-related employment do not always occur in the same year, the total impact is not always equal to the sum of the production and compliance related ranges.

EXHIBIT 8-46B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 6 COMPARED TO BASELINE, FTES, 2020 TO 2040



Notes: "Production-related" are effects on employment associated with changes to coal production that are expected as a result of Alternative 6. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is not produced because of changes associated with Alternative 6. This volume also becomes smaller over time given that the industry is getting smaller over time. "Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of Alternative 6 follow the pattern of overall forecast coal production. As shown, both the compliance-related and the production-related impacts of the Alternative are reduced over time. However, the slopes of these curves are not the same.

ENVIRONMENT AND HUMAN HEALTH

Exhibit 8-7 summarizes the categories of benefits and costs that are expected to result from Alternative 6 over the time frame of the analysis. Note that the categories are not mutually exclusive but rather complementary in several respects. For example, improved water quality will benefit biological resources, recreation and potentially human health. Exhibits 8-47A through C present the quantified impacts of Alternative 6, stream impacts, forest acre impacts, and air quality impacts.

EXHIBIT 8-47A. QUANTIFIED IMPACTS UNDER ALTERNATIVE 6 BY REGION: STREAM IMPACTS, AVERAGE ANNUAL STREAM MILES

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	174	0	0	1
Colorado Plateau	6	0	0	5
Gulf Coast*	36	0	0	7
Illinois Basin	51	0	0	11
Northern Rocky Mountains and Great Plains	22	0	0	6
Northwest*	2	0	0	0
Western Interior	2	0	0	0
Total	**293**	**0**	**0**	**30**

EXHIBIT 8-47B. QUANTIFIED IMPACTS UNDER ALTERNATIVE 6 BY REGION: FOREST AREA IMPACTS, AVERAGE ANNUAL FOREST ACRES

COAL REGION	IMPROVED ACRES	PRESERVED ACRES
Appalachian Basin	0	10
Colorado Plateau	0	0
Gulf Coast*	0	0
Illinois Basin	0	1
Northern Rocky Mountains and Great Plains	0	0
Northwest*	0	0
Western Interior	0	0
Total	**0**	**11**

EXHIBIT 8-47C. QUANTIFIED IMPACTS UNDER ALTERNATIVE 6 BY REGION: AVERAGE ANNUAL CHANGES IN MEHTANE EMISSIONS (MMCF)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	(10)	(106)	(116)
Colorado Plateau	0	0	0
Gulf Coast	0	0	0
Illinois Basin	(3)	(67)	(71)
Northern Rocky Mountains and Great Plains	(17)	(1)	(18)
Northwest	0	0	0
Western Interior	0	0	0
Total	**(30)**	**(174)**	**(204)**
Note: Totals may not sum due to rounding. Negative numbers indicate a decrease of emissions and positive numbers indicate an increase of emissions.			

8.7 ALTERNATIVE 7

Alternative 7 would apply when certain conditions exist within the proposed permit area that warrant enhanced permitting requirements. Those conditions would include—

- The presence of areas with pristine or unique hydrologic environments.
- The presence of geologic strata known to produce acid or toxic mine drainage.
- Watersheds with waters listed as impaired under section 303(d) of the Clean Water Act, if the parameter causing the impairment could be exacerbated by mining activities.
- The presence of steep slope areas.
- Proposals to place excess spoil or coal mine waste in perennial or intermittent streams or their buffer zones.

When these circumstances apply, this alternative would prohibit all mining activities in or within 100 feet of perennial streams. It would allow mining through intermittent streams if the applicant can demonstrate that the hydrologic form and ecological function of intermittent streams can and would be restored. It would prohibit the placement of excess spoil in intermittent streams. It would not include a definition of material damage to the hydrologic balance, but would require corrective action thresholds. It would place no new restrictions on activities in ephemeral streams.

For operations where enhanced permitting conditions were not warranted the requirements would remain the same as they do under the Baseline.

The following sections detail the potential effects of the Proposed Rule under this Alternative.

COMPLIANCE COSTS

Summing forecast operational costs expected to be borne by industry, industry administrative costs, and governmental administrative costs, we calculated the total compliance cost effects for Alternative 7. These results, annualized, are provided in Exhibit 8-48.

EXHIBIT 8-48. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 7, 7 PERCENT REAL DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL	INDUSTRY ADMINISTRATIVE	GOVERNMENT ADMINISTRATIVE	TOTAL
Appalachia	Surface	$26,500,000	$2,440,000	$2,770	$29,000,000
	UG	$1,670,000	$4,970,000	$7,150	$6,640,000
Colorado Plateau	Surface	$2,210,000	$77,700	$0	$2,290,000
	UG	$72,000	$48,300	$0	$120,000
Gulf Coast	Surface	$1,420,000	$67,800	$0	$1,490,000
Illinois Basin	Surface	$2,440,000	$64,400	$0	$2,510,000
	UG	$0	$26,100	$0	$26,100
Northern Rocky Mountains and Great Plains	Surface	$1,250,000	$40,700	$0	$1,290,000
Northwest	Surface	$11,700	$1,870	$0	$13,600
Western Interior	Surface	$98,800	$2,600	$0	$101,000
	UG	$0	$53	$0	$53
Annualized U.S. Compliance Cost Impacts	Surface	$34,000,000	$2,690,000	$2,770	$36,700,000
	UG	$1,740,000	$5,050,000	$7,150	$6,790,000
	TOTAL	**$35,700,000**	**$7,740,000**	**$9,930**	**$43,500,000**
Note: Totals may not sum due to rounding.					

MARKET WELFARE EFFECTS

Changes in Coal Production

Exhibits 8-49 and 8-50 show the projected change in coal production from 2020 through 2040 under Alternative 7. Under this Alternative, reductions in coal production occur for both surface and underground mining. As shown in Exhibit 8-49, surface mines account for half of the decline in production under this alternative. The net reduction in the volume of coal produced is forecast to lessen over the time period for the analysis, consistent with the declining demand for U.S. coal from retiring coal-fired power plants. In aggregate, however, the reduction in coal production under Alternative 7 is slightly more than those in the Proposed Rule. Exhibit 8-50 shows that approximately half this reduction is in the Appalachian Basin. Exhibit 8-51 displays the additional operational costs per ton for each model mine under Alternative 7. In general, the expected change in operational costs per ton are higher for surface mines than they are for underground mines, and the Illinois Basin and Western Interior are expected to experience the largest changes.

EXHIBIT 8-49. ANNUAL CHANGES IN COAL PRODUCTION UNDER ALTERNATIVE 7

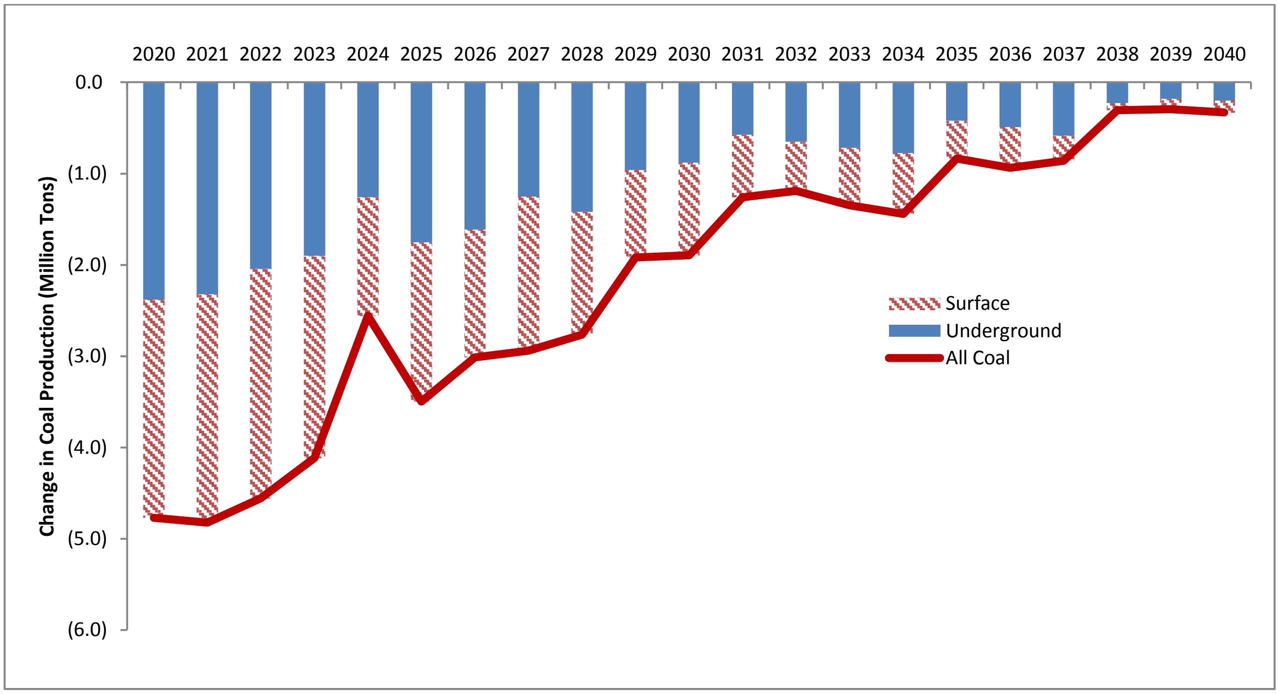
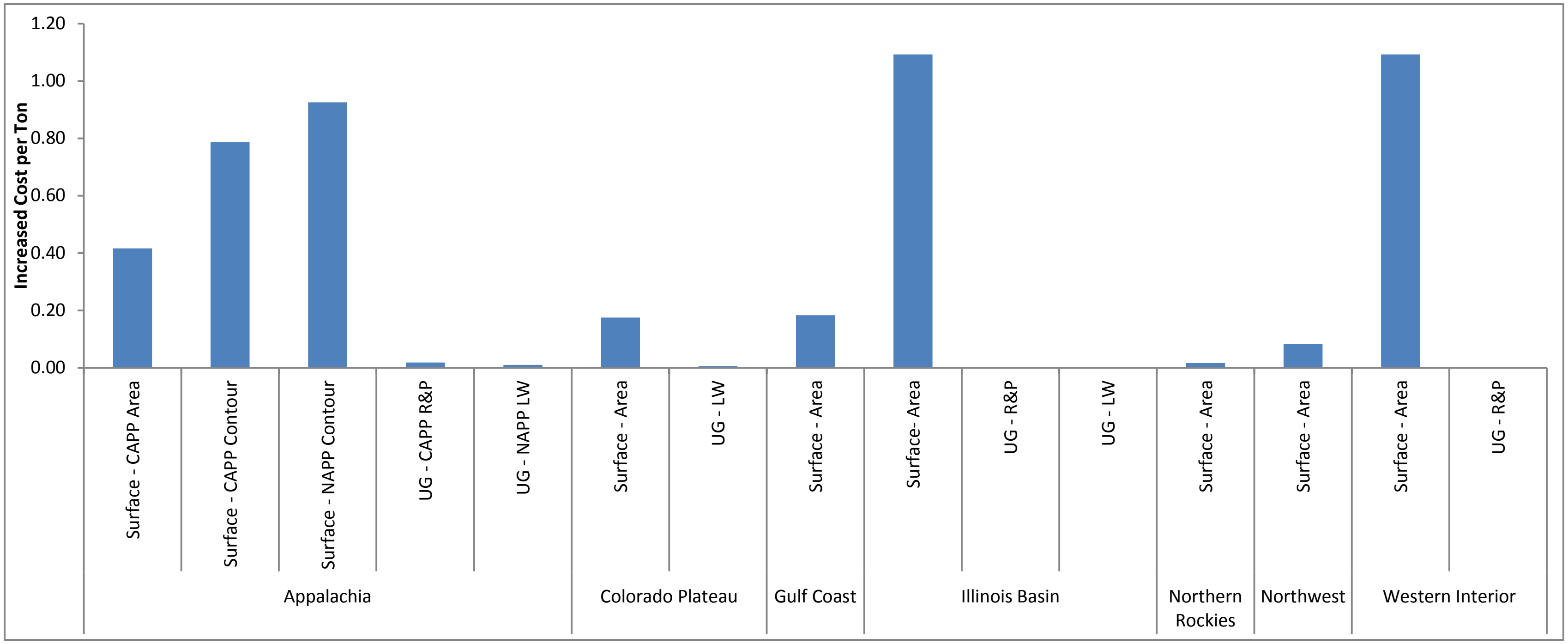


EXHIBIT 8-50. ANNUAL COAL PRODUCTION, 2020-2040

COAL REGION	BASELINE (MILLION TONS)	ALTERNATIVE 7 (MILLION TONS)	CHANGE (MILLION TONS)
Appalachian Basin	236	235	(1.1)
Colorado Plateau	56	56	0
Gulf Coast	54	54	0
Illinois Basin	171	170	(0.4)
North Rocky Mountains/ Great Plains	533	532	(0.7)
Northwest	2	2	0
Western Interior	1	1	0
TOTAL	**1,053**	**1,051**	**(2.2)**

EXHIBIT 8-51. INCREASED COST PER TON BY MODEL MINE, ALTERNATIVE 7



Coal Price Impacts

Related to changes in regional coal production, compliance costs, and coal market behavior, Exhibit 8-52 presents the estimated changes in coal prices under Alternative 7 for selected coal regions. The price projections presented in the exhibit suggest that regional coal prices will increase by 0.2 to 1.8 percent under Alternative 7. The increases are most significant in Central Appalachia.

EXHIBIT 8-52. COAL PRICE IMPACTS OF ALTERNATIVE 7 ($/TON)

REGION	2015 BASELINE	2015 ALT. 7	2020 BASELINE	2020 ALT. 7	2030 BASELINE	2030 ALT. 7	2040 BASELINE	2040 ALT. 7
NAPP	56.04	56.04	58.26	58.47	63.03	63.24	69.98	70.19
CAPP	64.00	64.00	67.34	68.56	70.43	71.65	74.27	75.48
ILLB	42.48	42.48	44.75	45.12	46.15	46.54	47.72	48.11
PRB	14.19	14.19	16.02	16.05	17.33	17.36	19.57	19.61
RCK	36.24	36.24	38.50	38.61	38.95	39.05	39.60	39.70

Notes:

CAPP = Central Appalachia
NAPP = Northern Appalachia
ILLB = Illinois Basin
PRB = Powder River Basin; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.
RCK = Rockies; represents a sub-region within the Northern Rocky Mountains/Great Plains OSMRE region.

Market Welfare Effects

Exhibit 8-53 presents the estimated change in market welfare, by year and in aggregate, for Alternative 7 over the 2020-2040 period. Similar to the Proposed Rule, market welfare losses for Alternative 7 largely reflect regulatory compliance costs and a transportation cost savings. This decrease in transportation costs suggests that under Alternative 7, on average, coal located relatively close to coal consumers becomes more cost competitive relative to coal located further away from consumers.

EXHIBIT 8-53. PRESENT VALUE AND ANNUALIZED WELFARE EFFECTS OF ALTERNATIVE 7, SEVEN PERCENT DISCOUNT RATE (MILLIONS, 2014 DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$12.5	$0.01	$12.5
2021	$12.3	$0.01	$12.3
2022	$10.8	$0.01	$10.8
2023	$11.2	$0.01	$11.2
2024	$21.0	$0.01	$21.0
2025	$14.4	$0.00	$14.4
2026	$15.2	$0.00	$15.2
2027	$11.9	$0.00	$11.9
2028	$13.5	$0.00	$13.5
2029	$16.4	$0.00	$16.4
2030	$13.8	$0.00	$13.8
2031	$14.4	$0.00	$14.4
2032	$14.6	$0.00	$14.6
2033	$12.6	$0.00	$12.6
2034	$11.0	$0.00	$11.0
2035	$11.7	$0.00	$11.7
2036	$10.4	$0.00	$10.4
2037	$10.0	$0.00	$10.0
2038	$10.5	$0.00	$10.5
2039	$9.1	$0.00	$9.1
2040	$8.1	$0.00	$8.1
Annualized Value Over the 2020-2040 Period-Discounted at 7%	**$24.5**	**$0.01**	**$24.5**

DISTRIBUTIONAL EFFECTS

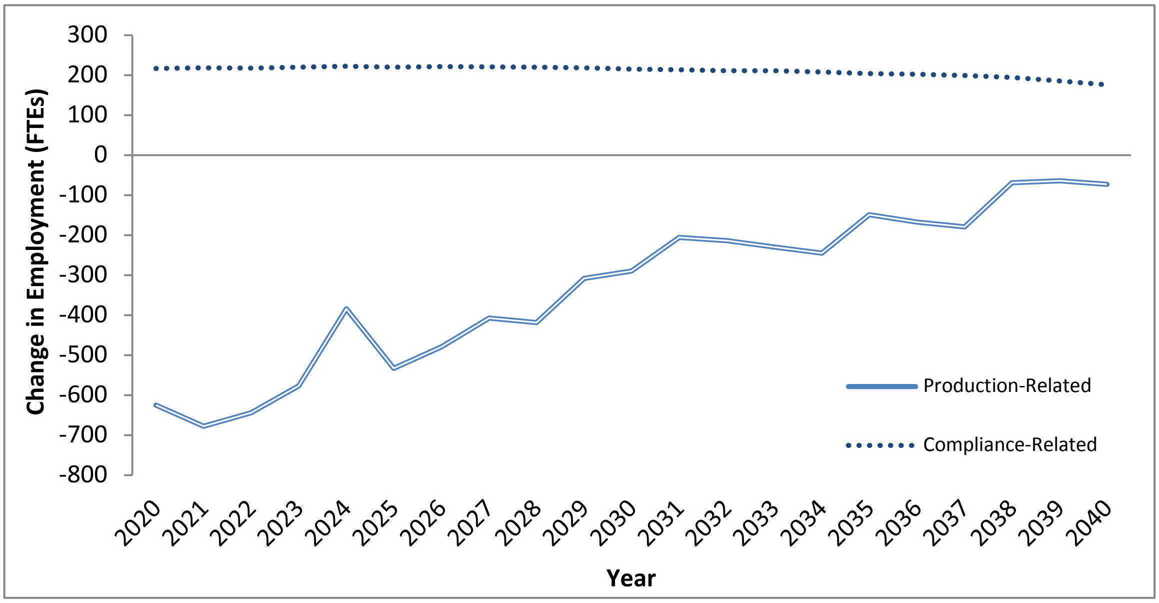
We estimate the changes in employment that are expected under Alternative 7, relative to the baseline. As shown in Exhibit 8-54A, production-related annual impacts to employment are expected to range from a reduction in demand for 680 FTEs to a reduction of 65 across all regions, with an average reduction in annual demand of 330 FTEs. Across all regions compliance-related employment effects are expected to range from an increase of 180 to 220 FTEs with an average annual increase of 210. Exhibit 8-54B shows the production-related and compliance-related effects as a line graph from 2020 to 2040.

EXHIBIT 8-54A. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 7, 2020-2040, EMPLOYMENT DEMAND: (FTE)

COAL REGION	METRIC	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE[4]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] UNDERGROUND[5]	PRODUCTION-RELATED EMPLOYMENT EFFECTS[3] SURFACE AND UNDERGROUND COMBINED[6]	COMPLIANCE-RELATED EMPLOYMENT EFFECTS[7]
Appalachian Basin	Average over 21 years:[1]	(82)	(180)	(270)	170
	Range in any year:[2]	(160) – (20)	(360) - (40)	(510) - (62)	140 - 180
Colorado Plateau	Average over 21 years:	0	0	0	12
	Range in any year:	0 - 0	0 - 1	0 - 1	10 - 13
Gulf Coast	Average over 21 years:	0	0	0	7
	Range in any year:	(1) - 1	0 - 0	(1) - 1	7 - 7
Illinois Basin	Average over 21 years:	(9)	(36)	(45)	12
	Range in any year:	(36) - 0	(140) - (1)	(170) - (2)	9 - 14
Northern Rocky Mountains and Great Plains	Average over 21 years:	(21)	0	(22)	6
	Range in any year:	(54) - 0	0 – 0	(54) - 0	5 - 6
Northwest	Average over 21 years:	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 0
Western Interior	Average over 21 years:	0	0	0	0
	Range in any year:	0 - 0	0 - 0	0 - 0	0 - 1
U.S. TOTAL	**Average over 21 years:**	**(110)**	**(220)**	**(330)**	**210**
	Range in any year:	**(230) - (20)**	**(450) - (42)**	**(680) - (65)**	**180 - 220**

[1] "Average over 21 years" is the average annual effect of the Alternative over the study period for the analysis on employment (2020-2040).
[2] "Range in any year" is the minimum and maximum effect on employment in any year in the study period.
[3] "Production-related employment effects" are calculated as effects associated with changes to coal production that are expected as a result of the Alternative. These are calculated using assumptions related to employment per ton of coal produced.
[4] The range of effects to Surface Employment represents the minimum and maximum effect in any year in the study period.
[5] The range of effects to Underground Employment represents the minimum and maximum effect in any year in the study period.
[6] The range of effects to Surface and Underground Combined employment represents the minimum and maximum impact in any year in the study period when the surface and underground mining effects are considered together. Because the minimum and maximum effects of the Alternative on surface and underground mining do not always occur in the same year, the Combined impact is not always equal to the sum of the Surface and Underground ranges.
[7] "Compliance-related employment effects" are calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance.

EXHIBIT 8-54B. ESTIMATED CHANGES IN ANNUAL EMPLOYMENT UNDER ALTERNATIVE 7 COMPARED TO BASELINE, FTES, 2020 TO 2040



Notes: **"**Production-related" are effects on employment associated with changes to coal production that are expected as a result of Alternative 7. These are calculated using assumptions related to employment per ton of coal produced. The production-related job losses are associated only with the coal that is not produced because of changes associated with Alternative 7. This volume also becomes smaller over time given that the industry is getting smaller over time. "Compliance-related" are effects on employment calculated as effects associated with changes to expenditures on compliance-related activities and are calculated using assumptions related to employment demand per dollar spent on compliance. The compliance-related job effects are a function of all coal that is produced in any year in each region. Thus, the level of compliance-related job effects of Alternative 7 follow the pattern of overall forecast coal production. As shown, both the compliance-related and the production-related impacts of the Alternative are reduced over time. However, the slopes of these curves are not the same.

ENVIRONMENT AND HUMAN HEALTH

Exhibit 8-7 summarizes the categories of benefits and costs that are expected to result from Alternative 7 over the time frame of the analysis. Note that the categories are not mutually exclusive but rather complementary in several respects. For example, improved water quality will benefit biological resources, recreation, and potentially human health. Exhibits 8-55A through C present the quantified impacts of Alternative 7, stream impacts, forest acre impacts, and air quality impacts.

EXHIBIT 8-55A. QUANTIFIED IMPACTS UNDER ALTERNATIVE 7 BY REGION: STREAM IMPACTS, AVERAGE ANNUAL STREAM MILES

COAL REGION	DOWNSTREAM IMPROVED	DOWNSTREAM PRESERVED	NOT FILLED	RESTORED
Appalachian Basin	158	1	4	1
Colorado Plateau	4	0	0	5
Gulf Coast	7	0	0	2
Illinois Basin	5	0	0	2
Northern Rocky Mountains and Great Plains	4	0	0	3
Northwest	0	0	0	0
Western Interior	0	0	0	0
Total	**178**	**1**	**4**	**14**

EXHIBIT 8-55B. QUANTIFIED IMPACTS UNDER ALTERNATIVE 7 BY REGION: FOREST AREA IMPACTS, AVERAGE ANNUAL FOREST ACRES

COAL REGION	IMPROVED ACRES	PRESERVED ACRES
Appalachian Basin	1,343	24
Colorado Plateau	259	0
Gulf Coast	97	0
Illinois Basin	38	1
Northern Rocky Mountains and Great Plains	21	0
Northwest	0	0
Western Interior	7	0
Total	**1,765**	**25**

EXHIBIT 8-55C. QUANTIFIED IMPACTS UNDER ALTERNATIVE 7 BY REGION: AVERAGE ANNUAL CHANGES IN MEHTANE EMISSIONS (MMCF)

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	(22)	(242)	(264)
Colorado Plateau	0	1	1
Gulf Coast	0	0	0
Illinois Basin	(5)	(108)	(114)
Northern Rocky Mountains and Great Plains	(18)	(2)	(19)
Northwest	0	0	0
Western Interior	0	0	0
Total	**(45)**	**(351)**	**(396)**
Note: Totals may not sum due to rounding. Negative numbers indicate a decrease of emissions and positive numbers indicate an increase of emissions.			

8.8 ALTERNATIVE 9

Alternative 9 analyzes the effects that would result from a reinstatement of the 2008 SBZ rule. Specifically, under Alternative 9, mining activities that would occur on the surface of land within 100 feet of perennial and intermittent streams, but not require diversion of the stream itself, would be allowed if the regulatory authority finds that avoidance is not reasonably possible and that the prohibition of these activities is not needed to meet fish and wildlife and hydrologic balance protection requirements. Where these activities would require diversion of the stream the regulatory authority can approve the impact only if these avoidance and protection requirements are met and only after applying additional requirements related to restoration of the stream hydrologic function. Restoration of stream ecological functions would not be required. The requirements of this alternative would not apply to placement of coal preparation plants located outside the permit area of a mine. This alternative would also require minimization of excess spoil and prohibits construction of fills with a larger capacity than needed. However, this alternative does not include many of the elements of the other alternatives.

Costs for Alternative 9 were found to be equal to baseline costs (refer to Appendix B for additional details). The engineering analysis determined that the costs for natural stream restoration were comparable to the estimated baseline costs for stream restoration. Because most current mining practices are consistent with the now-vacated 2008 SBZ Rule, Alternative 9 is anticipated to results negligible additional changes to ongoing and future mining operations and thus is not included in summary exhibits.

CHAPTER 9 | OTHER EQUITY CONSIDERATIONS AND REGULATORY IMPACTS

As required by applicable statutes and executive orders, this section summarizes analyses of equity considerations and other regulatory concerns associated with the Proposed Rule. This section assesses potential impacts, with respect to the following issues:

- **Unfunded mandates:** examines the implications of the Proposed Rule with respect to unfunded mandates as required by the UMRA;
- **Energy Impacts:** examines the impacts of the Proposed Rule on energy use, supply, and distribution as mandated under Executive Order 13211 (66 FR 28355, May 22, 2001);
- **Environmental justice:** considers potential issues for minority and low-income populations as required under E.O. 12898;
- **Children's health protection:** examines the potential impact of the Proposed Rule on the health of children in order to comply with E.O. 13045;
- **Tribal governments:** extends the discussion of federal unfunded mandates to include impacts on Native American tribal governments and their communities as mandated under E.O. 13175, “Consultation and Coordination With Indian Tribal Governments” (May 14, 1998);
- **Federalism:** considers potential issues related to state sovereignty as required under E.O. 13132;

9.1 UNFUNDED MANDATES ANALYSIS

Signed into law on March 22, 1995, UMRA places certain requirements on federal agencies that issue significant regulations that generate unfunded mandates. These include the preparation of a statement supporting the need to issue the regulation, and a description of prior consultation with representatives of affected state, local, and tribal governments. Requirements in the UMRA apply only to those federal regulations containing a “significant unfunded mandate.” The UMRA defines a significant unfunded mandate as a federal rule that either:

1. Results in estimated costs to state, local, and tribal governments, in aggregate, of $100 million or more in any one year; or
2. Results in estimated annual costs to the private sector of $100 million or more in any one year.

Federal rules are exempt from the UMRA requirements if:

1. The rule implements requirements specifically set forth in law; or
2. Compliance with the rule is voluntary for state and local governmental entities.

Based on these criteria set forth by the UMRA, we do not expect the Proposed Rule to generate a significant unfunded mandate. As reported earlier in this RIA, the total annualized compliance costs for this rule are on the order of $52 million (when calculated at a seven percent real rate of discount), which includes the costs that government agencies are expected to bear, on the order of $46,000 annualized.

9.2 ENERGY IMPACTS

Under E.O. 13211 (66 FR 28355, May 22, 2001), agencies are required to prepare and submit to OMB a Statement of Energy Effects for significant energy actions. This should include a detailed statement of any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) expected to result from the action and a discussion of reasonable alternatives and their effects.

The Office of Management and Budget provides guidance for implementing this Executive Order, outlining nine outcomes that may constitute "a significant adverse effect" when compared with the regulatory action under consideration:

- Reductions in crude oil supply in excess of 10,000 barrels per day (bbls);
- Reductions in fuel production in excess of 4,000 barrels per day;
- Reductions in coal production in excess of five million tons per year;
- Reductions in natural gas production in excess of 25 million Mcf per year;
- Reductions in electricity production in excess of one billion kilowatts-hours per year or in excess of 500 megawatts of installed capacity;
- Increases in energy use required by the regulatory action that exceed the thresholds above;
- Increases in the cost of energy production in excess of one percent;
- Increases in the cost of energy distribution in excess of one percent; or
- Other similarly adverse outcomes.[181]

Three of these criteria are potentially relevant to this analysis: (1) reduction in coal production in excess of five million tons per year, (2) reduction in electricity production in excess of one billion kilowatt-hours per year or in excess of 500 megawatts (MWs) of

[181] OMB. 2001. Memorandum For Heads of Executive Department Agencies, and Independent Regulatory Agencies, Guidance For Implementing E.O. 13211, M-01-27. http://www.whitehouse.gov/omb/memoranda/m01-27.html

installed capacity,[182] and (3) increases in the cost of energy production in excess of one percent. Below we assess whether this rule imposes a "significant adverse effect" on the energy industry, through a reduction in coal production, a reduction in electricity production, or an increase in the cost of energy production.

EVALUATION OF WHETHER THE PROPOSED RULE WILL RESULT IN A REDUCTION IN COAL PRODUCTION IN EXCESS OF FIVE MILLION TONS PER YEAR

The Proposed Rule may affect the regional distribution of domestic coal production, and the total quantity of coal produced. This analysis uses a "model mines" analysis to anticipate changes in industry practice that may result from the Proposed Rule. Coal market effects of the Proposed Rule are then forecast using the coal market model developed by EVA. See Chapter 3 for a detailed description of the analytic methodology used to estimate coal market impacts. Forecast changes in coal production expected to result from the Proposed Rule are reported in Chapter 4.

The Proposed Rule is not expected to result in a reduction in national coal production in excess of five million tons per year. The greatest single-year reduction in domestic coal production forecast under the Proposed Rule is expected to occur in year 2022, reaching 4.6 million tons. Note that the change in production from baseline conditions over the time period of this analysis is on average 1.9 million tons, significantly smaller than 4.6 million tons.

EVALUATION OF WHETHER THE PROPOSED RULE WILL RESULT IN A REDUCTION IN ELECTRICITY PRODUCTION IN EXCESS OF ONE BILLION KILOWATT-HOURS PER YEAR OR IN EXCESS OF 500 MEGAWATTS OF INSTALLED CAPACITY

The Proposed Rule may affect levels of domestic electricity production by influencing the costs of production. By increasing the costs of coal production, the Proposed Rule may lead to subsequent increases in the price of coal paid by power plants. Because coal makes up a significant part of the domestic energy mix, a change in the price of coal is expected to be reflected in domestic electricity prices, reducing market demand for electricity.

This analysis uses the EVA coal market model to predict the changes in electricity demand resulting from the Proposed Rule. On average over the time period for the analysis, electricity production is expected to decrease by 0.2 billion kilowatt-hours each year. Therefore, the proposed rule is not expected to exceed one billion kilowatt-hours per year. Some variability occurs throughout the time period for analysis.

[182] Installed capacity is the "total manufacturer-rated capacity for equipment such as turbines, generators, condensers, transformers, and other system components" and represents the maximum flow of energy from the plant or the maximum output of the plant.

EVALUATION OF WHETHER THE PROPOSED RULE WILL RESULT IN AN INCREASE IN THE COST OF ENERGY PRODUCTION IN EXCESS OF ONE PERCENT.

The Proposed Rule may affect both the cost of coal production and the cost of electricity production. To determine the effects of the Proposed Rule on the national cost of energy production, this analysis examines effects on coal production costs and electricity production costs separately.

Coal Production Costs

The Proposed Rule will introduce a number of new requirements to mine operators that may increase the overall costs of coal production. See Chapter 4 for a discussion of compliance costs related to the Proposed Rule. To compare compliance costs with the cost of coal production overall, this analysis examines regional production cost values for 2011-2013, as provided by EVA.[183] Average cash costs of publicly-traded coal companies are reported in Exhibit 9-1. Across the examined regions, the cost of coal production on a per-ton basis is lowest in the Powder River Basin region and highest in the Central Appalachia, which includes metallurgical coal. Publicly traded companies represent the majority of coal producers.

EXHIBIT 9-1. AVERAGE CASH COSTS OF PUBLICLY-TRADED COAL COMPANIES BY SUPPLY REGION, 2011-2013 (2014 DOLLARS PER TON)

REGION	2011 ($/TON)	2012 ($/TON)	2013 ($/TON)
Northern Appalachia	$39.37	$38.80	$38.74
Central Appalachia	$73.20	$79.12	$73.29
Illinois Basin	$32.41	$32.82	$31.50
Powder River Basin	$9.90	$10.38	$10.36
Source: EVA, 2014.			

A range of cost-per-ton estimates were applied to coal production projections under the Proposed Rule to obtain cost estimates of total domestic coal production. These estimates were then compared on an annual basis to total estimated compliance costs nationwide under the Proposed Rule. Compliance costs are estimated to make up less than one percent of total coal production costs, nationally, in every year within the study period. On average, compliance costs are expected to account for 0.1 percent of total coal production costs, nationally.

[183] EVA. 2014. U.S. Coal Quarterly Financial Report.

Electricity Production Costs

As coal is a costly input in the production of electricity, an increase in the cost of coal to electricity producers may increase the production costs of electricity nationally. To examine the expected effect of the Proposed Rule on the costs of electricity production, this analysis uses projections of electricity production costs generated by the EVA coal market model. Over the 21-year study period, the Proposed Rule is not expected to result in an increase in electricity production costs exceeding one percent. On average, the Proposed Rule is expected to increase electricity costs by 0.1 percent nationally.

9.3 ENVIRONMENTAL JUSTICE ANALYSIS

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" (February 11, 1994), requires federal agencies to identify disproportionately large and adverse human health or environmental effects of their programs, policies, and activities on minority and low-income populations.[184,185] Among other actions, agencies are directed to improve research and data collection regarding health and environmental effects in minority and low-income communities. OSMRE provides this analysis in the EIS of the Proposed Rule.

9.4 CHILDREN'S HEALTH PROTECTION

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (April 21, 1997), directs federal agencies and departments to evaluate the health effects of health-related or risk-related regulations on children.[186] For economically significant rules concerning an environmental health or safety risk that may disproportionately affect children, Executive Order 13045 also requires an explanation as to why the planned regulation is preferable to other potentially effective and feasible alternatives.[187] While the environmental protection provisions of the Proposed Rule may improve health conditions for children, the Proposed Rule is not subject to E.O. 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children.

[184] As stated in Executive Order 12898, a minority is an individual who is a member of one of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic.

[185] As stated in Executive Order 12898, low-income populations are identified using the annual statistical poverty thresholds from the Census Bureau's Current Population Reports on Income and Poverty.

[186] In addition, two separate directives issued by EPA, "Policy on Evaluating Health Risks to Children" (October 1995) and "National Agenda to Protect Children's Health from Environmental Threats" (October 1996), call for consideration of children's health within risk assessments and other components of regulatory analyses.

[187] As defined in Executive Order 13045, an economically significant rule is any rulemaking that has an annual effect on the economy of $100 million or more, or would adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local or tribal governments or communities.

9.5 TRIBAL GOVERNMENT ANALYSIS

Executive Order 13175: Consultation and Coordination with Indian Tribal Governments (65 FR 67249, November 9, 2000), requires OSMRE to develop an accountable process to ensure “meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.” OSMRE provides this analysis in Chapter 5 of the EIS of the Proposed Rule.

9.6 FEDERALISM ANALYSIS

Executive Order 13132, entitled “Federalism” (64 FR 43255, August 10, 1999), requires OSMRE to develop a process to ensure “meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.” Policies that have federalism implications are defined in the Executive Order to include regulations that have “substantial direct effects on the States [in terms of compliance costs], on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." In addition, policies have federalism implications if they preempt State law. In terms of compliance costs, the Federal government must provide the necessary funds to pay the direct costs incurred by State and local governments in complying with the regulation if the rule:

1. Results in direct expenditures to state and local governments in aggregate of $25 million in any one year; or
2. Results in expenditures greater to state and local governments greater than one percent of their annual revenues in any one year

We do not anticipate that this rule will result in significantly greater compliance costs for the States above thresholds listed above. As noted above, government agencies are expected to bear annualized costs on the order of $46,000. We also do not expect this rule to impact the relationship between the Federal government and the States or on the distribution of power and responsibilities among the various levels of government, as specified in the Order. Thus, Executive Order 13132 does not apply to this rule.

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APPENDIX A: INITIAL REGULATORY FLEXIBILITY ANALYSIS

INITIAL REGULATORY FLEXIBILITY ANALYSIS

This Initial Regulatory Flexibility Analysis (IRFA) considers the extent to which the economic impacts resulting from the Proposed Rule could be borne by small businesses. The analysis presented is conducted pursuant to the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996. Information for this analysis was gathered from the Small Business Administration (SBA), the Office of Surface Mining Reclamation and Enforcement (OSMRE), and the Mine Safety and Health Administration (MSHA).

INTRODUCTION

First enacted in 1980, the RFA was designed to ensure that Federal Agencies consider the potential for its regulations to unduly inhibit the ability of small entities to compete. The goals of the RFA include increasing the government's awareness of the impact of regulations on small entities and to encourage agencies to exercise flexibility to provide regulatory relief to small entities.

When a Federal agency proposes regulations, the RFA requires the agency to prepare and make available for public comment an analysis that describes the effect of the rule on small entities (i.e., small businesses, small organizations, and small government jurisdictions).[188] For this rulemaking, this analysis takes the form of an IRFA. Under 5 U.S.C., Section 603(b) of the RFA, an IRFA is required to contain:

i. A description of the reasons why action by the agency is being considered;

ii. A succinct statement of the objectives of, and legal basis for, the Proposed Rule;

iii. A description of and, where feasible, an estimate of the number of small entities to which the Proposed Rule will apply;

iv. A description of the projected reporting, recordkeeping and other compliance requirements of the Proposed Rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;

v. Identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the Proposed Rule; and,

vi. Each initial regulatory flexibility analysis shall also contain a description of any significant alternatives to the Proposed Rule that accomplish the stated objectives

[188] 5 U.S.C. § 601 et seq.

of applicable statutes and which minimize any significant economic impact of the Proposed Rule on small entities.

REASONS WHY ACTION IS BEING CONSIDERED, OBJECTIVES OF, AND LEGAL BASIS FOR THE PROPOSED RULE

It is OSMRE's opinion that this Federal action is needed to improve implementation of the Surface Mining Control and Reclamation Act (SMCRA) with regard to stream protection. OSMRE has identified three subcomponents of that need. ***Much of the text in this section is taken from OSMRE's Draft Environmental Impact Statement and can be referred to for more information.***

First, there is a need to insure that mining operations collect sufficient data to assess the likelihood of impacts during mining and post-mining periods, and to insure appropriate reclamation. Second, there is a need to develop an objective standard for "material damage to the hydrologic balance outside of the permit area." Third, there is a need to ensure that operators and regulatory authorities use advances in information, technology, science and methodologies related to stream protection. The following sections describe the overall need for improved stream protection and address each of the three sub-components in more detail.

NEED FOR THE FEDERAL ACTION

The need for this federal action is to improve implementation of SMCRA with regard to stream protection. OSMRE has identified several subcomponents of that need: First, there is a need to clearly define the point at which adverse mining impacts on groundwater and surface water (both of which provide streamflow) reach an unacceptable level; that is, the point at which they cause material damage to the hydrologic balance outside the permit area. Second, there is a need to collect adequate premining data about the site of the proposed mining operation and adjacent areas to establish a comprehensive baseline against which the impacts of mining can be compared. Third, there is a need for effective monitoring of groundwater and surface water during and after mining and reclamation activities to provide real-time information on the impacts of mining and to enable prompt detection of any adverse trends and implementation of corrective measures before it is either too late to take remedial measures or exceedingly costly to do so. Fourth, there is a need to ensure protection or restoration of perennial and intermittent streams and related resources, especially the headwaters streams that are critical to maintaining the ecological health and productivity of downstream waters. Fifth, there is a need to ensure the use of objective standards in making important regulatory and operational decisions with a potential impact on perennial and intermittent streams. Sixth, there is a need to ensure that permittees and regulatory authorities make use of advances in information, technology, science, and methodologies related to surface and groundwater hydrology, surface-runoff management, stream restoration, soils, and revegetation.

NEED FOR REGULATORY IMPROVEMENTS TO BETTER PROTECT STREAMS

SMCRA Section 201(c) requires OSMRE to "publish and promulgate such rules and regulations as may be necessary to carry out the purposes and provisions of this Act." Congress identified stream protection as a fundamental purpose of SMCRA. Among its findings in support of the legislation, Congress determined that:

> many surface coal mining operations result in disturbances of surface areas that burden and adversely affect commerce and the public welfare by … polluting the water, by destroying fish and wildlife habitats, by impairing natural beauty, … and by counteracting governmental programs and efforts to conserve soil, water, and other natural resources.

The federal action analyzed in this RIA will better prevent or remediate the adverse impacts that Congress described when it made this finding. Despite the enactment of SMCRA and the promulgation of federal regulations implementing the statute, surface coal mining operations continue to have negative effects on streams, fish, and wildlife. These conditions are documented in the literature surveys and studies discussed in Chapter 4. Further evidence is available through several decades of observing the impacts of coal mining operations. These documented and observed problems have prompted OSMRE to consider whether it should take a different approach in the regulations implementing the following SMCRA provisions related to stream protection:

- Section 510(b)(3) of SMCRA requires that each surface coal mining operation be designed to prevent material damage to the hydrologic balance outside the permit area. Current regulations intentionally do not define the extent of damage that is allowable and how much damage constitutes "material damage," an approach that was intended to afford regulatory authorities flexibility in making determinations on a case-by-case basis (48 FR 43973, September 26, 1983).
- Section 515(b)(2) of SMCRA requires that mined land be restored to a condition capable of supporting the uses that it was capable of supporting prior to mining, or higher or better uses of which there is reasonable likelihood, provided certain conditions are met. Existing rules and permitting practices have focused primarily on the land's suitability for a single approved post-mining land use. OSMRE believes it is essential to ensure that land be restored to support all uses that it was capable of supporting before mining.
- Section 515(b)(10) of SMCRA requires that operators minimize disturbances to the prevailing hydrologic balance at the mine site and to the quality of water in surface and ground water systems. As discussed in more detail in Chapter 2, in order to provide the most effective implementation of this statutory requirement, OSMRE is evaluating a number of options. OSMRE is considering how buffer zones may be most effectively used to minimize disturbances to the hydrologic balance and to water quality. OSMRE is evaluating regulatory options for avoidance of acid and toxic drainage from mine sites. OSMRE also seeks the most effective regulation of

excess spoil fill construction, because of the potential effects of such fills to effect the hydrologic balance and water quality.

- Sections 515(b)(19) and 516(b)(6) of SMCRA require the operator to establish a diverse, effective, permanent vegetative cover of the same seasonal variety native to the area on all regraded areas and other lands affected by mining. However, evidence indicates that areas which were previously forested have commonly been reclaimed and revegetated as heavily compacted grasslands with scrub trees--vegetation that is not representative of native pre-mining vegetation. OSMRE is considering Alternatives that would implement these SMCRA provisions more effectively.
- Sections 515(b)(24) and 516(b)(11) of SMCRA require, subject to certain limitations, that surface coal mining and reclamation operations minimize disturbances and adverse impacts on fish, wildlife, and related environmental values. These provisions also require operations to “achieve enhancement of such resources where practicable.” Reconstructed streams, however, often neither look nor function the way they did before mining. The regulatory emphasis has been primarily upon creating a channel sufficient to convey postmining flows, while minimizing channel erosion and sediment loading. Such limited reclamation results in streams that may no longer support the benthic and other aquatic communities that they did before mining. Additionally, efforts to enhance fish, wildlife, and related environmental values despite the mandate of both the statutes and the regulations, have not been evenly implemented as part of state reclamation programs. Examples exist of highly successful enhancement projects, while in other areas of the nation, these activities are unfortunately limited.
- OSMRE’s current rules at 30 CFR § 816.73 allow excess spoil fills to be constructed by end-dumping. With end-dumping, operators push or dump rock overburden over the side of the mountain to cascade into the valley below, with the larger rocks rolling to the bottom of the valley to form the underdrain. Based on several decades’ experience implementing the rules, OSMRE is reexamining whether this technique violates a number of SMCRA requirements. For instance, some end-dumping may not comply with Section 515(b)(22)(A) of SMCRA which provides that all excess spoil material resulting from surface coal mining operations must be “transported and placed in a controlled manner in position for concurrent compaction and in such a way to assure mass stability and to prevent mass movement.” End-dumping, moreover, can result in elevated dissolved ion concentrations in water leaving the site, and significant increases in concentrations of total dissolved solids (TDS) in receiving streams, both of which may adversely affect fish and wildlife in contravention of section 515(b)(24) of SMCRA. Further, construction of end-dumped rock fills can result in inconsistent development of the underdrains required under section 515(b)(2) of SMCRA, leading to structural instability of the fill.

NEED FOR ADEQUATE DATA

To effectively evaluate the impacts of a mining operation, and to ensure implementation of SMCRA's requirements, the regulatory authority must have both sufficient baseline data and sufficient data about ongoing changes to stream-related resources and biota. Adequate data about the conditions before the mining activity is critical to ascertaining the extent and cause of any changes that do occur after mining is underway; this information in turn is critical to correcting problems if and when they occur. To ensure that the necessary corrections can be made to prevent and mitigate damage, the regulations must specify the types of information that need to be collected, and the locations, timing, and frequency of information collection. As discussed above, section 510(b)(3) of SMCRA requires that each surface coal mining operation be designed to prevent material damage to the hydrologic balance outside the permit area. Section 515(b)(10) of SMCRA requires, in essence, that surface coal mining and reclamation operations "minimize the disturbances to the prevailing hydrologic balance at the mine-site and in associated offsite areas and to the quality and quantity of water in surface and ground water systems both during and after surface coal mining operations and during reclamation." For underground mining, section 516(b)(9) of SMCRA requires operations to minimize disturbances to the prevailing hydrologic balance at the mine-site and associated offsite areas, and to ensure the quantity of water. Sections 515(b)(24) and 516(b)(11) of SMCRA require, subject to certain limitations, that surface coal mining and reclamation operations minimize disturbances and adverse impacts on fish, wildlife, and related environmental values; and also require operations to "achieve enhancement of such resources where practicable."

As discussed previously, studies indicate that environmental degradation is still occurring despite the current requirements within the implementing regulations of SMCRA. OSMRE has determined that this research indicates that effective evaluation of trends and impacts on groundwater, surface water, and stream-related resources and biota, would require additional monitoring of data beyond what is currently required by existing regulations. Additional water quality parameters must be monitored both in the baseline condition and within any effluent leaving mine sites. Similarly, existing regulations do not provide for collection of baseline data sufficient to determine the biological condition of streams. Consequently characteristics of the aquatic community in the stream are not well documented in SMCRA permit files. This impedes regulators' ability to assess whether an operation is adequately minimizing adverse impacts on fish, wildlife, and related environmental values, as required by sections 515(b)(24) and 516(b)(11). More complete and accurate baseline information is needed to improve regulators' ability to determine whether mine plans are designed in accordance with the Act, and whether operations are being conducted in accordance with mining plans. For example, better baseline data would facilitate a more thorough cumulative hydrologic impact analysis (CHIA); would help set objective and measurable material damage standards; and would help identify and address hydrologic problems that may arise after permit issuance.

Additional data is also needed to provide sufficient warning when water impacts are approaching thresholds where corrective actions should be taken to prevent further damage. This change would help operators and regulators evaluate the potential for future violations, such as material damage to the hydrologic balance.

Increased frequency of inspection and improved reporting is needed to ensure effective compliance with SMCRA requirements for restoration of approximate original contours (AOC) on the site post-mining. OSMRE has identified a number of instances where the regulatory authority overlooked inadequate contour restoration until late in the process (at which point correcting the problem would be overly expensive or cause unacceptable disruption of stabilized conditions). To address such problems, OSMRE is evaluating Alternatives to ensure sufficient reporting and inspection regarding contour restoration.

NEED FOR ADEQUATE OBJECTIVE STANDARDS

In order to effectively implement SMCRA's requirements related to stream protection, regulations must allow permittees and operators, as well as regulatory authorities, to effectively evaluate compliance and limit or prevent adverse impacts, as appropriate.

The regulatory standards must provide an objective threshold with clear and predictable standards for preventing "material damage to the hydrologic balance outside the permit area," as required by section 510(b)(3) of SMCRA. That section requires that each surface coal mining operation be designed to prevent material damage to the hydrologic balance outside the permit area. However, neither OSMRE nor most states have defined this term. A clear Federal definition of "material damage", and federal minimum standards or criteria against which to measure whether material damage has occurred, is needed to provide a basis for oversight of state implementation of this statutory requirement.

As noted above, based on observed changes, OSMRE believes that existing permitting and performance standards implementing section 515(b)(10) of SMCRA may be inadequate to minimize disturbances to the prevailing hydrologic balance at the mine site and to the quality of water in surface and ground water systems. More specific, more clearly defined and objective standards would ensure implementation of this statutory requirement.

Improved implementation of section 515(b)(3) of SMCRA is also needed. This section requires, with certain exceptions, that mined land be restored to AOC. Restoration of mined land to a surface configuration that includes convex and concave terrain patterns and landforms typical of pre-mining condition could more effectively meet this requirement. The existing rules governing AOC restoration are general, subjective, and lacking in specificity. Too often, this has resulted in postmining surface configurations that are significantly flatter than the premining configuration; that lack many of the landform features found prior to mining; and that have significantly altered drainage patterns and stream characteristics and functions.

NEED TO APPLY CURRENT INFORMATION, TECHNOLOGY, AND METHODOLOGIES

This Federal action is also designed to incorporate significant advances in scientific knowledge that has occurred since OSMRE's permanent program regulations were adopted in 1979, and then substantially amended, starting in 1983.

First, new information exists on the adverse impacts that coal mining can cause to water resources and stream biota. As discussed in more detail in Chapter 4, there are many recent publications of studies and literature surveys that evaluate the impacts of surface coal mining and reclamation operations on water quantity and quality, as well as related biological resources.

Second, since OSMRE's earlier rulemakings, there have been many improvements in technologies and methodologies for prediction, prevention, mitigation, and reclamation of coal mining impacts on hydrology, streams, fish, wildlife, and related resources. These advances have included significant improvements in the cost-effectiveness and availability. As discussed in more detail in Chapter 4, OSMRE has identified major improvements in technology and methodology related to identifying, quantifying, mapping, and modeling mining operations and their impacts on the environment. Examples of such improvements are discussed below.

Advances in identification and prediction of impacts on stream resources. Since the 2008 SBZ rule, there have been significant improvements in analysis of the impacts of mining on stream resources. For instance, coal mining-related regulatory programs have traditionally focused on acid mine drainage and sediment loads as the sources of potential problems. As described in Chapter 4 of the SPR DEIS, however, multiple chemical constituents produced by mining cause significant increases in conductivity and total dissolved solids (TDS) in streams below many surface mines, particularly below excess spoil fills. OSMRE has learned that those changes can have significant toxic effects on streams, leading to a loss of sensitive aquatic organisms even when downstream habitats are otherwise intact. Emerging science indicates that problems can include golden algae blooms and adverse impacts to fish and wildlife from the discharge of chemical constituents not considered in past rulemaking efforts. Further, data now indicate that some pollutants, such as selenium, may bio-accumulate. Accumulation of pollutants in biological systems over time may adversely affect biota and human health. In addition new studies indicate that toxic discharges may continue for decades even after reclamation of the site has otherwise been successful according to current requirements for restoration of the land itself.

Similarly, information is now available connecting the life histories of aquatic taxa with stream flow regimes, and this information allows better characterization of streams. For example, taxa requiring a full year of aquatic larval development in highly oxygenated waters would not be expected to be found in ephemeral streams and many intermittent streams.

Landform elements such as ridges, valleys, hill slopes, and streams can now be measured quantitatively in a way not feasible until recently. Permit reviewers can now utilize computers and sophisticated software to process huge amounts of elevation data acquired from stereo satellite and airborne images, LiDAR, and radar to produce much more accurate maps and models of surface configuration than was possible a few short years ago. This information may allow state regulators to determine the total volume of earth that a mining operation has or will displace, based on the position of the coal seams and volume of overburden relative to the premining topography. These data can also be used to plan for restoration of smaller-scale features that blend into the surrounding topography within a watershed. By contrast, reclamation practices under existing regulations often rely on construction of uniformly sized and spaced structures and features.

Advances in reclamation techniques. Emerging science now provides much better information on effective reclamation practices related to stream protection. During the last decade, the scientific community has made great strides in developing geomorphic reclamation strategies that reduce erosion and improve water quality. These improvements are not reflected in current regulations. More traditional approaches to restoration of AOC have created large reclaimed acreages that resemble landscapes of agricultural fields, urban recreational parks, or construction fill sites such as large dam embankments, spillways, or waterway diversions. Modern GPS-enabled equipment can incorporate the use of geomorphic principles in reclamation design, and can provide a closer approximation of the highly dissected and randomly spaced and sized drainage patterns of an undisturbed landscape. The Los Angeles abrasion test (which focuses on rock hardness) and the sodium or magnesium sulfate soundness test (which distinguishes between rocks based on their susceptibility to weathering) can be used to assess the appropriateness of material used in fills. Hydrologic modeling programs such as the US Army Corps of Engineers Hydrologic Engineering Center, Hydrologic Modeling System (HEC-HMS) can predict with greater accuracy the flow pattern and volume of runoff that would occur under different rainfall scenarios at defined locations. Use of programs such as the by Civil Software Design, LLC Sediment, Erosion, Discharge by Computer Aided Design (SEDCAD) program can more effectively design and evaluate erosion and sediment control systems. Such improvements in reclamation may significantly improve stream restoration and long-term landscape stability.

Advances in reforestation techniques have been shown to decrease the detrimental effects of storm runoff. Science now indicates that high nutrient loads can have negative, cumulative impacts downstream, but that riparian buffer zones can reduce those nutrient loads and associated impacts. OSMRE experience over the past thirty years indicates that extensive herbaceous ground cover on reclaimed areas can inhibit the establishment and growth of trees and shrubs. The dense herbaceous ground covers often used to control erosion compete with newly planted trees and tree seedlings for soil nutrients, water, and sunlight, and provide habitat for rodents and other animals that damage tree seedlings and young trees. Use of the Federal Geographic Data Committee's U.S. National Vegetation Classification Standard, and other generally accepted standards, is needed to promote consistent identification of plant communities and development of appropriate revegetation plans to restore those communities following mining.

DESCRIPTION AND ESTIMATE OF THE NUMBER OF SMALL ENTITIES TO WHICH THE RULE APPLIES

DEFINITION OF A SMALL ENTITY

Three types of small entities are defined in the RFA:

i. **Small Business.** Section 601(3) of the RFA defines a small business as having the same meaning as small business concern under section 3 of the Small Business Act. This includes any firm that is independently owned and operated and is not dominant in its field of operation. The U.S. SBA has developed size standards to carry out the purposes of the Small Business Act, and those size standards can be found in 13 CFR § 121.201. The size standards are matched to North American Industry Classification System (NAICS) industries. The SBA definition of a small business applies to a firm's parent company and all affiliates as a single entity.

ii. **Small Governmental Jurisdiction.** Section 601(5) defines small governmental jurisdictions as governments of cities, counties, towns, townships, villages, school districts, or special districts with a population of less than 50,000. Special districts may include those servicing irrigation, ports, parks and recreation, sanitation, drainage, soil and water conservation, road assessment, etc. Most tribal governments will also meet this standard. When counties have populations greater than 50,000, those municipalities of fewer than 50,000 can be identified using population reports. Other types of small government entities are not as easily identified under this standard, as they are not typically classified by population.

iii. **Small Organization.** Section 601(4) defines a small organization as any not-for-profit enterprise that is independently owned and operated and not dominant in its field. Small organizations may include private hospitals, educational institutions, irrigation districts, public utilities, agricultural co-ops, etc. Depending upon state laws, it may be difficult to distinguish whether a small entity is a government or non-profit entity. For example, a water supply entity may be a cooperative owned by its members in one case and in another a publicly chartered small government with the assets owned publicly and officers elected at the same elections as other public officials.

DESCRIPTION OF SMALL ENTITIES TO WHICH THE RULE WILL APPLY

This IRFA focuses on identifying small businesses that will be directly affected by the Proposed Rule. In particular, we focus on identifying potential impacts to small mine operators who will bear the direct compliance burdens of the rule. Small governmental jurisdictions or small organizations as defined by the SBA are not expected to be directly regulated by this rule. See Exhibit A-1 for a description of the coal industry as defined by the NAICS system and the SBA size standards.

EXHIBIT A-1. INDUSTRY SECTORS ANTICIPATED TO BE DIRECTLY AFFECTED BY THE PROPOSED RULE

DESCRIPTION OF INCLUDED INDUSTRY SECTORS	NAICS CODE	SBA SIZE STANDARD
Bituminous Coal and Lignite Surface Mining This industry comprises establishments primarily engaged in one or more of the following: (1) surface mining of bituminous coal and lignite; (2) developing bituminous coal and lignite surface mine sites; (3) surface mining and beneficiating (e.g., cleaning, washing, screening, and sizing coal) of bituminous coal; or (4) beneficiating (e.g., cleaning, washing, screening, and sizing coal), but not mining, bituminous coal.	212111	500 employees
Bituminous Coal Underground Mining This industry comprises establishments primarily engaged in one or more of the following: (1) underground mining of bituminous coal; (2) developing bituminous coal underground mine sites; and (3) underground mining and beneficiating of bituminous coal (e.g., cleaning, washing, screening, and sizing coal).	212112	500 employees
Anthracite Mining This industry comprises establishments primarily engaged in one or more of the following: (1) mining anthracite coal; (2) developing anthracite coal mine sites; and (3) beneficiating anthracite coal (e.g., cleaning, washing, screening, and sizing coal).	212113	500 employees

ESTIMATE OF THE NUMBER OF SMALL ENTITIES TO WHICH THE RULE WILL APPLY

The goal of this analysis is to identify the number of small entities with mining permits that fall within each coal region. However, due to the complexity in corporate structures in the coal mining industry, it is difficult to calculate the exact number of small entities (defined by the RFA as having 500 employees or less) that could be affected by this rule. The coal mining industry is continually changing and it is common for large mining operators to merge with smaller operators, creating complicated business relationships between parent corporations and subsidiaries.

When determining how to estimate the number of small coal mining companies in the U.S. that could be affected by the Proposed Rule, we followed MSHA's method for calculating compliance costs to small business, as described in a recently proposed

Preliminary Regulatory Economic Analysis. [189] In that analysis, MSHA examined the impact of a Proposed Rule on a mine with 500 or fewer employees (the SBA threshold), and also gave careful consideration to "small mines" with fewer than 20 employees. MSHA's rational behind these thresholds was as follows.[190]

> MSHA has also examined the impact of the Proposed Rule on mines with fewer than 20 employees, which MSHA and the mining community have traditionally referred to as "small mines." These small mines differ from larger mines not only in the number of employees, but also in economies of scale in material produced, in the type and amount of production equipment, and in supply inventory. Therefore, their costs of complying with MSHA's rules and the impact of the Agency's rules on them would also tend to be different. This analysis complies with the requirements of the RFA for an analysis of the impact on "small entities" while continuing MSHA's traditional definition of "small mines."

To estimate the number of small entities potentially affected by this rule, we use MSHA 2013 data on mines, mine controllers, employees, and production to identify mines likely operated by small businesses. We began by assuming that each mine controller listed in MSHA's 2013 mine data represented a separate entity and eliminated data where controllers listed had greater than 500 employees. We then reviewed publically available information on listed controllers reporting over 250 employees to determine if the controlling entity had greater than 500 employees. Employers reporting over 500 employees were then excluded from the small business database.

In developing these estimates, we excluded all operating companies reporting no employees and entities reporting less than 2,000 tons annual production, as well as inactive mines. These mines are assumed not to be representative of a typical small entity in the industry.

Using these methods, we classify two types of small entities. We identify controllers with 500 or fewer employees (SBA threshold), and, as a subset, controllers having fewer than 20 employees (MSHA threshold). We present results first by the MSHA threshold, followed by the SBA threshold.

Since controllers can operate mines across regions and mining methods, we present total number of controllers by size across the industry. As shown in Exhibit A-2, 134 small entities fall under MSHA's small mine definition and 284 classify as small entities using the SBA threshold for small entities. Exhibits A-3 and A-4 present the number of *mines* operated by these small entities by regions and mine type. As shown, most of the small mining entities operate mines in Appalachia, regardless of definition. As shown, 96 percent of mines operated by small entities are in the Appalachian Basin using the MSHA

[189] MSHA. 2010. Preliminary Regulatory Economic Analysis for Lowering Miners' Exposure to Respirable Coal Mine Dust Including Continuous Personal Dust Monitors Proposed Rule. United States Department of Labor, Office of Standards, Regulations, and Variances. Washington, GPO.

[190] Ibid. Print Pg. 159.

definition of one to 19 employees; 91 percent of mines operated by small entities using the SBA definition of one to 500 employees are in the Appalachian Basin.

EXHIBIT A-2. ESTIMATED TOTAL NUMBER OF SMALL ENTITIES IN THE COAL INDUSTRY, 2013

SMALL BUSINESS SIZE	ESTIMATED NUMBER OF SMALL ENTITIES
1-19 Employees (MSHA small mine threshold)	134
1-500 Employees (SBA threshold)	284
Source: MSHA. 2013. MSHA Annual Coal Production Data 2013. Provided by OSMRE July 24, 2014. As noted, reported.	

EXHIBIT A-3. ESTIMATED NUMBER OF MINES BY REGION AND MINE TYPE OPERATED BY SMALL ENTITIES WITH BETWEEN 1 AND 19 EMPLOYEES, 2013

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	129	27	156
Colorado Plateau	0	0	0
Gulf Coast	0	0	0
Illinois Basin	3	0	3
Northern Rocky Mountains	1	0	1
Northwest	0	0	0
Western Interior	2	0	2
Total	**135**	**27**	**162**
Source: MSHA. 2013. MSHA Annual Coal Production Data 2013. Provided by OSMRE July 24, 2014. Note: Included in these estimates are all mines estimated to be operated by small entities, rather than the number of small entities. The number of affected small entities is smaller (132) than the number of mines provided here (162), as some controllers of these mines operate more than one mine.			

EXHIBIT A-4. NUMBER OF MINES BY REGION AND MINE TYPE OPERATED BY SMALL ENTITIES WITH BETWEEN 1 AND 500 EMPLOYEES, 2013

COAL REGION	SURFACE	UNDERGROUND	TOTAL
Appalachian Basin	260	89	349
Colorado Plateau	3	2	5
Gulf Coast	0	0	0
Illinois Basin	12	3	15
Northern Rocky Mountains	3	1	4
Northwest	1	0	1
Western Interior	6	2	8
Total	**285**	**97**	**382**

Source: MSHA. 2013. MSHA Annual Coal Production Data 2013. Provided by OSMRE July 24, 2014.
Note: Included in these estimates are all mines estimated to be operated by small entities, rather than the number of small entities. The number of affected small entities is slightly smaller (284) than the number of mines provided here (382), as some controllers of these mines operate more than one mine.

After consideration of all nine alternatives, OSMRE has selected Alternative 8 as the Proposed Rule. The following section presents the impacts to small entities for the Proposed Rule. For descriptions of the potential costs of the other Alternatives, please see the section titled "Description of alternatives to the Proposed Rule that would minimize significant economic impacts on small entities."

ESTIMATE OF COMPLIANCE COSTS BY REGION

Estimates of the cost to small entities from the Proposed Rule are summarized in Exhibits A-5 and A-6. Operational costs represent the increased costs of the Proposed Rule on mine operation and extraction of coal on a per ton basis. These are summarized in Exhibit A-5.

Administrative costs relate primarily to monitoring and permitting requirements of the Proposed Rule and are summarized in Exhibit A-6.[191] Both one-time and annual (recurring) administrative costs were calculated for purposes of the analysis. To be conservative, i.e., more likely to overstate than understate impacts, we include in this small entity analysis the administrative costs that will need to be paid or financed in the first year of mine operations (initial costs). Therefore, the average annual administrative costs would be expected to be lower at small mines than estimated here.

We also note that estimated administrative costs approximate the average costs per permit. However, some administrative costs, such as increased monitoring requirements, may in fact vary depending on the size of the mine. To the extent that small mines are

[191] Administrative cost estimates were developed as part of the Paperwork Reduction Analysis for this rule and are detailed in Chapter 4 of the RIA.

physically smaller, they may need to collect fewer samples than assumed in the standard mine used to estimate costs. Consequently, the per mine administrative costs values may overstate the impacts to small mines. Conversely, other administrative costs may not scale down with the size of a mine, such as paperwork requirements. These costs may therefore be larger on a per ton produced basis for small mines than for larger mines.

EXHIBIT A-5. INCREASED OPERATIONAL COMPLIANCE COSTS PER TON OF PROPOSED RULE (UNDISCOUNTED DOLLARS)

COAL REGION	SURFACE MINING	UNDERGROUND MINING
Appalachian Basin	$0.40	$0.01
Colorado Plateau	$0.12	$0.01
Gulf Coast	$0.16	Not Applicable
Illinois Basin	$0.60	$0.00
Northern Rocky Mountains	$0.01	Not Applicable
Northwest	$0.06	Not Applicable
Western Interior	$0.60	$0.00
Sources: Morgan Worldwide Analysis 2014; OSMRE PRA Analysis 2014.		

EXHIBIT A-6. REGIONAL MINE COST ASSUMPTIONS – ADMINISTRATIVE COMPLIANCE COSTS PER SMALL MINE (INITIAL YEAR COSTS)

COAL REGION	SURFACE	UNDERGROUND
Appalachian Basin	$44,239	$53,617
Colorado Plateau	$38,717	$38,624
Gulf Coast	$39,017	Not Applicable
Illinois Basin	$39,017	$38,624
Northern Rocky Mountains	$38,717	Not Applicable
Northwest	$46,095	Not Applicable
Western Interior	$39,017	$38,624
Note: Initial year administrative costs are reported because they will result in the most conservative cost analysis. These include all one-time administrative costs as well as recurring costs. Average annual costs would be expected to be lower than those reported here. Source: OSMRE PRA Analysis 2014.		

ANALYSIS OF COMPLIANCE COSTS TO SMALL MINES

Of particular interest to small businesses are compliance costs as share of revenue. The average sales prices for coal by state, or revenue per ton of coal, are reported by the U.S.

Energy Information Administration (EIA).[192] These state level revenues are presented in Exhibit A-7 below for states with small entities.[193]

EXHIBIT A-7. AVERAGE COAL MINE REVENUES PER TON, 2012

STATE	SURFACE	UNDERGROUND
Alabama	$104.51	$107.73
Alaska[1]	$14.24	Not Applicable
Arkansas[1]	Not Applicable	$59.63
Colorado[1]	$37.54	$37.54
Illinois	$45.12	$54.18
Indiana	$51.33	$52.94
Kansas[1]	$59.63	Not Applicable
Kentucky	$64.70	$62.24
Maryland[1]	$55.67	$55.67
Missouri [1]	$59.63	Not Applicable
Montana[1]	$18.11	$18.11
New Mexico[1]	$36.74	$36.74
Ohio	$44.38	$49.39
Oklahoma[1]	$59.63	$59.63
Pennsylvania	$74.04	$72.69
Tennessee[1]	$73.51	$73.51
Utah[1]	$34.92	$34.92
Virginia	$98.84	$114.91
West Virginia	$73.60	$86.02
Wyoming[1]	$14.24	$14.24

Source: Calculated using average coal price, EIA 2013 Data for 2012.
http://www.eia.gov/coal/data.cfm#prices table:
http://www.eia.gov/coal/annual/pdf/table28.pdf

[1] Some states had revenue data withheld for confidentiality. Where only total revenue data was available, we applied it to both surface and underground mines. In addition, in the Western Interior region, revenue data were withheld for Arkansas, Kansas, and Missouri. Revenue for these states is estimated as equal to Oklahoma, which borders these states and is in the Western Interior region. In the Northwest region, revenue data were withheld for Alaska. As no data were available for any states in this region, to be conservative revenue is estimated as equal to Wyoming, the lowest revenue state.

[192] U.S. EIA. 2013a. Annual Coal Report 2012. Table 28: Average Sales Price of Coal by State and Mine Type, 2012 and 2011. U.S. Department of Energy.

[193] State level data was used throughout this IRFA. Some states had revenue data withheld for confidentiality. Where only total revenue data was available, we applied it to both surface and underground mines.

The following tables present the number of small entities whose combined operational and administrative costs fall into five categories of percentages by region. We present separately by operator size and mine type. See Exhibits A-8 and A-9.

EXHIBIT A-8. ANNUAL COST OF PROPOSED RULE AS A PERCENT OF REVENUE FOR SURFACE MINES OPERATED BY SMALL ENTITIES (1-19 EMPLOYEES)[1]

COAL REGION	MINE TYPE	TOTAL NUMBER OF SMALL ENTITIES AFFECTED	NUMBER OF AFFECTED SMALL ENTITIES, BY IMPACT ON REVENUE					AVERAGE SHARE OF REVENUE AFFECTED
			0 TO 5 PERCENT REVENUE EFFECT	5 TO 10 PERCENT REVENUE EFFECT	10 TO 15 PERCENT REVENUE EFFECT	15 TO 20 PERCENT REVENUE EFFECT	OVER 20 PERCENT REVENUE EFFECT	
Appalachian Basin	Surface	129	70	31	10	9	9	7.1%
	Underground	27	19	4	3	1	0	4.3%
Colorado Plateau	Surface	0	0	0	0	0	0	0%
	Underground	0	0	0	0	0	0	0%
Gulf Coast	Surface	0	0	0	0	0	0	0%
Illinois Basin	Surface	3	2	1	0	0	0	4.0%
	Underground	0	0	0	0	0	0	0%
Northern Rocky Mountains	Surface	1	0	0	1	0	0	10.3%
Northwest	Surface	0	0	0	0	0	0	0%
Western Interior	Surface	2	1	0	0	0	1	15.3%
	Underground	0	0	0	0	0	0	0%

Sources: Data from OSMRE: MSHA, Calendar year 2013 coal production data, as provided by OSMRE on July 24, 2014; Average Coal Price per region taken from EIA 2013 Data for 2012. http://www.eia.gov/coal/data.cfm#prices table: http://www.eia.gov/coal/annual/pdf/table28.pdf.
Note: Included in these estimates are all mines estimated to be operated by small entities, rather than the number of small entities. The number of affected small entities is smaller (132) than the number of mines provided here (162), as some controllers of these mines operate more than one mine.

EXHIBIT A-9. ANNUAL COST OF PROPOSED RULE AS A PERCENT OF REVENUE FOR SURFACE MINES OPERATED BY SMALL ENTITIES (1-500 EMPLOYEES)[1]

COAL REGION	MINE TYPE	TOTAL NUMBER OF SMALL ENTITIES AFFECTED	NUMBER OF AFFECTED SMALL ENTITIES, BY IMPACT ON REVENUE					AVERAGE SHARE OF REVENUE AFFECTED
			0 TO 5 PERCENT REVENUE EFFECT	5 TO 10 PERCENT REVENUE EFFECT	10 TO 15 PERCENT REVENUE EFFECT	15 TO 20 PERCENT REVENUE EFFECT	OVER 20 PERCENT REVENUE EFFECT	
Appalachian Basin	Surface	260	190	37	12	11	10	4.7%
	Underground	89	76	5	6	2	0	2.5%
Colorado Plateau	Surface	3	3	0	0	0	0	0.5%
	Underground	2	2	0	0	0	0	0.1%
Gulf Coast	Surface	0	0	0	0	0	0	0%
Illinois Basin	Surface	12	10	2	0	0	0	2.5%
	Underground	3	3	0	0	0	0	1.3%
Northern Rocky Mountains	Surface	3	2	0	1	0	0	3.5%
Northwest	Surface	1	1	0	0	0	0	0.6%
Western Interior	Surface	6	5	0	0	0	1	6.0%
	Underground	2	2	0	0	0	0	0.7%

Sources: Data from OSMRE: MSHA, Calendar year 2013 coal production data, as provided by OSMRE on July 24, 2014; Average Coal Price per region taken from EIA 2013 Data for 2012. http://www.eia.gov/coal/data.cfm#prices table: http://www.eia.gov/coal/annual/pdf/table28.pdf.

Note: Included in these estimates are all mines estimated to be operated by small entities, rather than the number of small entities. The number of affected small entities is smaller (284) than the number of mines provided here (382), as some controllers of these mines operate more than one mine.

DESCRIPTION OF REPORTING AND RECORDKEEPING EFFORTS

In order to comply with the Paperwork Reduction Act (PRA), OSMRE estimated the aggregate additional hour burden of the collection of information for the proposed alternative. This calculation included estimated additional labor hours, wage costs, and non-wage related costs as a result of the Proposed Rule on behalf of the PRA analysis requirement for this rule. These efforts were calculated on an annual basis per permit for mine operators and State Regulating Authorities and were based on experience and collaboration with the states.

IDENTIFICATION OF RELEVANT FEDERAL RULES THAT MAY DUPLICATE, OVERLAP, OR CONFLICT WITH THE PROPOSED RULE

A number of Federal statutes, regulations and policies impact coal mining operations, including the Surface Mining Control Act (SMCRA); the Clean Water Act (CWA); and the Clean Air Act. In addition, individual state regulations, guidance, and polices may affect mining practices. These regulations, guidance, and policies make up a component of the existing baseline for coal mining practices and are discussed in Chapter 3 of the RIA.

DESCRIPTION OF ALTERNATIVES TO THE PROPOSED RULE THAT WOULD MINIMIZE SIGNIFICANT ECONOMIC IMPACTS ON SMALL ENTITIES

An IRFA should include a description of the steps the agency has taken to minimize significant economic impacts on small entities, consistent with the stated objectives of applicable statutes. This should include a statement of the factual, policy, and legal reasons for selecting the alternative adopted in the final rule, and why other alternatives to the rule considered by the agency were rejected.

In this IRFA, we describe and evaluate the Preferred Alternative to this rule. For a description of each alternative please see Chapter 1 of the RIA. To meet the requirements of this IRFA, below we present the average annual cost per company as a percent of revenue, see Exhibits A-10 and A-11 below. In Alternatives 2 through 4 and 6, the same numbers of mines are expected to be affected. Under Alternative 5, mines outside of the Appalachian Basin do not experience an increase in compliance costs, but regional changes in production could affect demand for coal from those mines. However the specifics of how these changes will be distributed across individual mines is unknown. Under Alternative 7 not all mines would be affected. Applicability factors were applied to the number of mines affected.

DESCRIPTION OF MEASURES TO MINIMIZE ECONOMIC IMPACTS ON SMALL ENTITIES

Section 507(c) of SMCRA, 30 U.S.C. § 1257(c), establishes the small operator assistance program (SOAP). To the extent that funds are appropriated for that program, this provision of SMCRA authorizes us to provide small operators with training and financial assistance in preparing certain elements of permit applications. An operator is eligible to receive training and assistance if his or her probable total annual production at all locations will not exceed 300,000 tons. Under section 507(c)(1) of SMCRA, 30 U.S.C. §1257(c)(1), and 30 CFR § 795.9, the following permit application activities are eligible for financial assistance under SOAP:

- Preparation of the determination of the probable hydrologic consequences of mining, including collection and analysis of baseline data and any engineering analyses and designs needed for the determination.
- Collection and analysis of geological data.
- Development of cross-sections, maps, and plans.
- Collection of information on archaeological and historical resources and preparation of any related plans.
- Development of preblast surveys.
- Collection of site-specific information on fish and wildlife resources and preparation of fish and wildlife protection and enhancement plans.

These activities include many of the new permit application requirements in the proposed rule; e.g., the expanded baseline data requirements concerning hydrology, geology, and the biological condition of streams and the expanded requirements for site-specific fish and wildlife protection and enhancement plans. If this proposed rule is adopted as a final rule, we intend to interpret section 507(c)(1) of SMCRA, 30 U.S.C. § 1257(c)(1), in a manner that will maximize SOAP funding eligibility for the cost of compliance with the new permit application requirements. We invite comment on whether 30 CFR § 795.9 could or should be revised to incorporate more of the new permit application requirements in this proposed rule. In addition, section 507(c)(2) of SMCRA, 30 U.S.C. § 1257(c)(2), provides that, as part of SOAP, we must provide or assume the cost of training eligible small operators concerning the preparation of permit applications and compliance with the regulatory program.

SOAP funding is subject to appropriation from the Federal expense portion of the Abandoned Mine Reclamation Fund established under section 401(a) of SMCRA, 30 U.S.C. § 1231(a). Section 401(c)(9) of SMCRA, 30 U.S.C. § 1231(c)(9), caps SOAP funding at $10 million per year. If this proposed rule is adopted, we intend to provide training to assist small operators in meeting the additional requirements of the proposed rule. In addition, if this proposed rule is adopted, we intend to request $10 million in appropriations to provide financial assistance to small operators in developing permit applications. SOAP assistance should substantially reduce compliance costs for small operators by offsetting the cost of most of the new permit application requirements. The principal compliance cost not eligible for SOAP funding would be the expense of implementing the expanded requirements for monitoring groundwater, surface water, and the biological condition of streams.

EXHIBIT A- 10. ANNUAL COMPLIANCE COST OF RULE PER MINE OPERATED BY A SMALL ENTITY, PERCENT OF ANNUAL REVENUE (1-19 EMPLOYEES)

ALTERNATIVE	MINE TYPE	NUMBER OF AFFECTED SMALL MINES	SHARE OF ANNUAL REVENUE AFFECTED (AVERAGE SMALL MINE)
Alternative 2	Surface	135	17.7%
	UG	27	4.3%
Alternative 3	Surface	135	17.0%
	UG	27	4.3%
Alternative 4	Surface	135	17.0%
	UG	27	4.3%
Alternative 5[1]	Surface	129	10.9%
	UG	27	4.3%
Alternative 6	Surface	135	7.8%
	UG	27	3.8%
Alternative 7[2]	Surface	120	16.9%
	UG	27	4.4%

Notes:
Included in these estimates are all mines estimated to be operated by small entities, rather than the number of small entities. The number of affected small entities is smaller than the numbers provided here, as some controllers of these mines operate more than one mine.

[1] Under Alternative 5, mines outside of the Appalachian Basin do not experience an increase in compliance costs, but regional changes in production could affect demand for coal from those mines. However the specifics of how these changes will be distributed across individual mines is unknown.
[2] Under Alternative 7 not all mines would be affected, applicability factors are applied to the number of mines affected.

Sources: Data from OSMRE: MSHA, Calendar year 2013 coal production data, as provided by OSMRE on July 24, 2014; Average Coal Price per region taken from EIA 2013 Data for 2012. http://www.eia.gov/coal/data.cfm#prices table: http://www.eia.gov/coal/annual/pdf/table28.pdf.

EXHIBIT A- 11. ANNUAL COMPLIANCE COST OF RULE PER MINE OPERATED BY A SMALL ENTITY, PERCENT OF ANNUAL REVENUE (1-500 EMPLOYEES)

ALTERNATIVE	MINE TYPE	NUMBER OF AFFECTED SMALL MINES	SHARE OF ANNUAL REVENUE AFFECTED (AVERAGE SMALL MINE)
Alternative 2	Surface	285	8.5%
	UG	97	2.4%
Alternative 3	Surface	285	7.3%
	UG	97	2.4%
Alternative 4	Surface	285	7.2%
	UG	97	2.3%
Alternative 5[1]	Surface	260	7.1%
	UG	27	2.5%
Alternative 6	Surface	285	3.7%
	UG	97	2.1%
Alternative 7[2]	Surface	244	7.3%
	UG	91	2.4%

Notes:
Included in these estimates are all mines estimated to be operated by small entities, rather than the number of small entities. The number of affected small entities is smaller than the numbers provided here, as some controllers of these mines operate more than one mine.

[1] Under Alternative 5, mines outside of the Appalachian Basin do not experience an increase in compliance costs, but regional changes in production could affect demand for coal from those mines. However the specifics of how these changes will be distributed across individual mines is unknown.
[2] Under Alternative 7 not all mines would be affected, applicability factors ae applied to the number of mines affected.

Sources: Data from OSMRE: MSHA, Calendar year 2013 coal production data, as provided by OSMRE on July 24, 2014; Average Coal Price per region taken from EIA 2013 Data for 2012. http://www.eia.gov/coal/data.cfm#prices table: http://www.eia.gov/coal/annual/pdf/table28.pdf.

Appendix B: Analysis of Potential Impacts to Model Mines

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In Conjunction with:

Industrial Economics

January 2015

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATED GLOSSARY

Longwall Mining *- An automated form of underground coal mining characterized by high recovery and extraction rates, feasible only in relatively flat-lying, thick, and uniform coalbeds. A high-powered cutting machine is passed across the exposed face of coal, shearing away broken coal, which is continuously hauled away by a floor-level conveyor system. Longwall mining extracts all machine-minable coal between the floor and ceiling within a contiguous block of coal, known as a panel, leaving no support pillars within the panel area.*

Mineral Removal Area – *Area underlain by the coal seam designated for mining.*

Room and Pillar Mining *- The most common method of underground mining in which the mine roof is supported mainly by coal pillars left at regular intervals. Rooms are places where the coal is mined; pillars are areas of coal left between the rooms. Room-and-pillar mining is done either by conventional or continuous mining.*

Area Mining – *Area mining is a surface mining technique that may remove all or part of the coal seams in the upper fraction of a mountain, ridge or hill.*

Contour Mining – *Partial removal of a coal seam along the outcrop. This type of mining creates a highwall in the hillside along the line of maximum overburden removal.*

Stripping Ratio *- The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) thickness of overburden to thickness of coal, (2) volume of overburden to volume coal, (3) weight of overburden to weight of coal, or (4) cubic yards of overburden to tons of coal. A stripping ratio commonly is used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.*

Coal Resource – *The amount of in-situ coal within the project boundaries. This tonnage of coal is not subject to any recovery processes.*

Coal Reserve *–The amount of recoverable coal considering losses due to mining methods and coal processing.*

Representative Mine – *An existing coal mine in the respective coal producing region that is utilized to provide topographical, geological and coal seam information for the Model mine.*

Model Mine – *The Model mine approach is a vehicle for assessing the nature and characteristics of mining in a respective coal mining region.*

Hollow (Valley) Fill - A *fill structure consisting of any material, other than coal processing waste and organic material, placed across or through the head of a valley or hollow where side slopes of the existing hollow measured at the steepest point are greater than 20 degree or the average slope of the profile of the hollow from the toe of the fill to the top of the fill is greater than 10 degrees.*

1. INTRODUCTION

The U.S. Office of Surface Mining Reclamation and Enforcement (OSMRE) is revising its regulations that implement the Surface Mining Reclamation and Control Act (SMCRA). In what is known as the Stream Protection Rule[1], OSMRE proposed revisions to current regulations in eleven separate categories and is currently preparing a Regulatory Impact Analysis (RIA) and an Environmental Impact Statement (EIS) to assess potential effects of the preferred alternative and the remaining alternatives.[2] Appendix B will provide information and analyses that can be utilized in the selection of the preferred option.

Appendix B is a support document for the analysis of each of the nine action alternatives described in the Stream Protection Rule Environmental Impact Statement. It describes the analysis used to compare the various methods of coal mining in the United States through both production and cost analysis in order to provide information for the cost/benefit modeling of all Action Alternatives. The analysis of the action alternatives in Appendix B includes the following: identification of the coal producing regions in the US, definition of typical mining practices and trends in each region, application of the trends and practices to the creation of representative model mines, and cost analysis of each action alternative's effect on the representative model mines.

The representative model mine approach was taken in order to assess the effects of the Stream Protection Rule (SPR) on the coal mining industry in the US. This approach uses the model mines of each of the coal mining regions to quantify the financial effects of the SPR. The model mine approach simplifies the analysis, while representing the majority of coal mining operations in the US. In order to quantify the financial cost of each alternative on the model mines, relevant cost categories were chosen. These cost categories included Haulage, Landforming, Stream Restoration, Stream Enhancement, Reforestation/PLMU and Enhanced Permitting.

1.1. Organization of this Report

Appendix B will be separated into five (5) sections as shown below:

Section 1 – Introduction. This section lays the framework for this study. The background, scope, study areas, and limitations are discussed and defined.

Section 2 – Coal Producing Regions. Overview of the seven coal producing regions in the US.

Section 3 – Regional Mining Trends. Analysis of Current mining methods and trends in the coal producing regions of the US.

Section 4 – Model Mines. Constructing representative model mines to approximate both the mining method and the representative annual coal production for prevalent mining methods in each region.

Section 5 – Cost Section. Individual mining cost categories for each model mine.

[1] Stream Protection Rule; Environmental Impact Statement, 75 FR 34667, 34667 (June 18, 2010) (Notice of Intent to prepare an environmental impact statement and amend 30 CFR Chapter VII).
[2] *Id.*

1.2. Review of Mining Methods

Coal is mined by surface or underground methods, which vary by region and geology. For the purposes of this document, surface coal mining is defined as mining where the soil and rock overlying the coal seam are first removed, while underground coal mining is defined as all coal extraction methods where the overlying rock is left in place and the coal is removed and transported to the surface through shafts or tunnels.

The surface mining methods discussed in this document include area mining, open pit mining, and contour mining. Area mining occurs when a mining operation removes an entire seam of coal from outcrop to outcrop. Open pit mining refers to coal mining operations where the entire coal seam lies below drainage and does not necessarily outcrop within the coal removal area. Finally, contour mining defines mining along an outcrop by following the contours of the topography. A contour mining operation removes only the coal along the outcrop, leaving the higher mining ratio coal behind. Mining ratio refers to the volume of waste rock that must be removed per unit ton of coal. For the purposes of this document, all surface mining will either be referred to as area mining (including open pit mining) or contour mining.

Underground coal mining methods include room and pillar mining (continuous) and longwall mining. Room and pillar mining is a selective mining method where pillars of coal are left to support the roof. Longwall mining is a high extraction method where panels of uniformly deposited coal are mined completely, allowing the roof to fall in behind the mine operation. Longwall mining includes the use of room and pillar methods for development work.

Additional coal mining methods exist, including remining, augering and highwall surface mining and conventional drill and blast underground mining. These methods are not covered in this document as they are not as predominant as the aforementioned methods.

1.3. Scope of Study/Limitations

The scope of this appendix is limited by the nature of the model mine approach. Each of the approximately 1200 coal mines in the United States is unique. The individual characteristics of each mine makes a comprehensive, mine by mine, analysis impracticable. Therefore, the model mine analysis provides a method of analyzing representative mining scenarios to forecast potential impacts of each alternative to cost and operational trends in the industry.

The model mine approach is used to analyze the elements under each alternative that might impact the design of different types and sizes of mining operations. The goal of the analysis was to design mines that are representative of the majority of operations located in each region. However, real individual mining operations would be different in practice based on specific factors such as topography, geology, and hydrology that cannot be model in detail with this type of general analysis. Therefore, this analysis outlines impacts that would be expected to occur under similar conditions as those encountered by real operations but does not necessarily imply that the results would be applicable to all mining operations in a certain region.

2. COAL PRODUCING REGIONS

The Draft Environmental Impact Statement divides the coal mining regions of the United States into seven regions (Figure 1):

- Appalachian Basin
  - Alabama
  - Eastern Kentucky
  - Maryland
  - Ohio
  - Pennsylvania
  - Tennessee
  - Virginia
  - West Virginia
- Illinois Basin
  - Illinois
  - Indiana
  - Western Kentucky
- Gulf Coast
  - Louisiana
  - Mississippi
  - Texas
- Western Interior
  - Arkansas
  - Kansas
  - Missouri
  - Oklahoma
- Colorado Plateau
  - Arizona
  - Colorado
  - New Mexico
  - Utah
- Northern Rocky Mountains and Great Plains
  - Montana
  - Wyoming
  - North Dakota
  - Colorado
- Northwest Region
  - Alaska

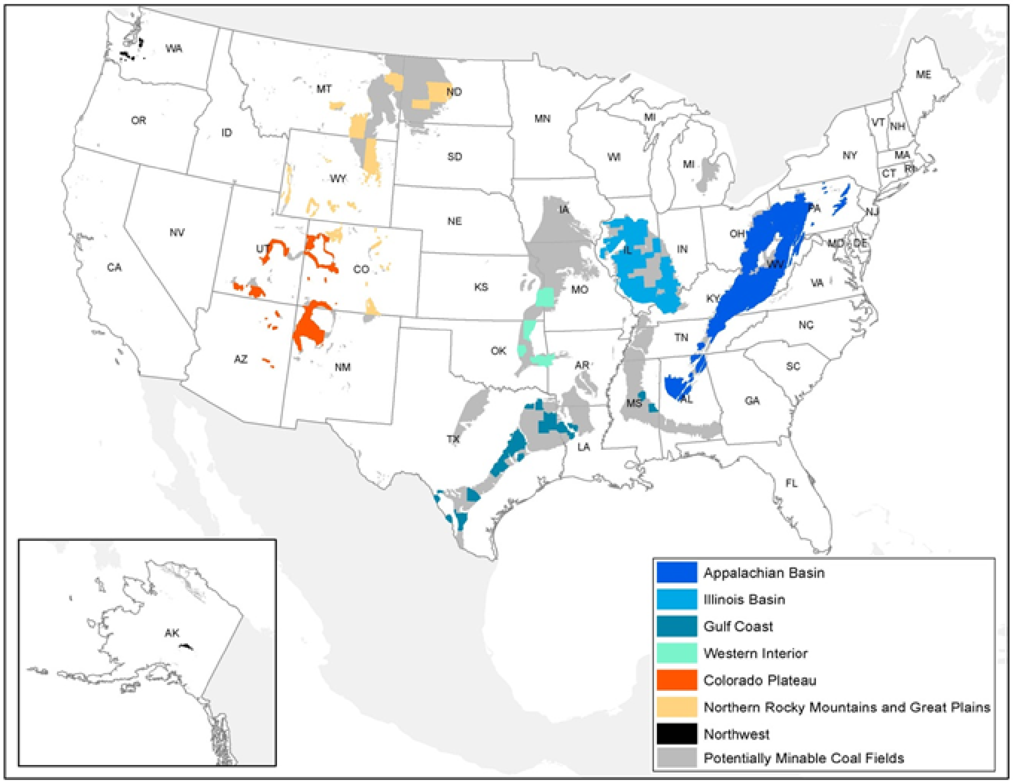

Figure 1: United States Coal Regions (Modified)

2.1. Data Review

Mining in each region was categorized based on mining method and yearly production. In order to select representative mines, the most current, available coal production data were used:

- EIA Annual Coal Report 2011[3]
- 2012 MSHA quarterly production data[4]
- 2012 SNL listing of top producing mines[5]

The use of three separate data sets was necessary. The EIA data includes information on mining method, while the MSHA and SNL data do not. The MSHA data allowed a comparison of average and median production, as well as a more thorough statistical evaluation of mine frequency and size distribution in each region. The SNL data provided a greater understanding of the size and distribution of the largest producing mines in the region. Thus, all three data sets were used to conduct a thorough analysis of coal production and distribution.

The MSHA database was the most complete, and considered the most accurate, of the three sources; therefore, it was the primary source used for assessing annual coal production and the distribution of

[3] U.S. Energy Information Administration, "Annual Coal Report 2011" November 8, 2012, available at: http://www.eia.gov/coal/annual/.

[4] MSHA 2012 Data and analysis by Energy Ventures Analysis, Inc (received August 23, 2013).

[5] SNL Energy. Various regional coal mine production tables. 12 months ended Q4'12.

surface and underground mine sizes. The EIA and SNL data subsidized the MSHA database. While multiple datasets were used, a consistent source of data was used for each type of analysis. Any variations in production numbers between data sets were insignificant.

Due to the time frame of this project, the regional analysis and model mine work was originally completed using 2010 production data. The regional analysis has since been completed a second time using 2012 production data. Both the 2010 and 2012 production data produce similar results. For this study, the 2012 production data and the 2010 production-based representative mine summaries will be shown.

2.2. Overall Coal Production Review

The first step of the regional review process was compiling an overview of coal production by region and mine type (Table 1). Based on the data compilation, it was determined if a model mine was necessary for each region based on the region's contribution to national coal production.

	Underground			Surface			Total		
	# of Mines	2012 Production (1,000 tons)	Percent of Total Production	# of Mines	2012 Production (1,000 tons)	Percent of Total Production	# of Mines	2012 Production (1,000 tons)	Percent of Total Production
Southern Appalachia	8	12,570	1.2%	38	6,984	0.7%	46	19,554	1.9%
Central Appalachia	333	77,872	7.7%	326	69,279	6.8%	659	147,152	14.5%
Northern Appalachia	85	104,329	10.3%	246	22,796	2.2%	331	127,125	12.5%
Colorado Plateau	18	44,886	4.4%	8	30,475	3.0%	26	75,361	7.4%
Gulf Coast	0	0	0.0%	18	51,110	5.0%	18	51,110	5.0%
Illinois Basin	38	92,493	9.1%	41	34,367	3.4%	79	126,860	12.5%
Northern Rocky Mtns & Grt Plns	2	10,344	1.0%	26	455,320	44.8%	28	465,664	45.8%
Northwest	0	0	0.0%	1	2,052	0.2%	1	2,052	0.2%
Western Interior	2	446	0.0%	10	1,144	0.1%	12	1,590	0.2%
TOTAL	**486**	**342,939**	**33.7%**	**714**	**673,529**	**66.3%**	**1,200**	**1,016,468**	**100%**

Table 1: Annual Coal Production by Region, 2012[6] (MSHA)

The 2012 MSHA data show that the following regions (in descending order) produce nearly 98% of the coal mined in the United States:

- Northern Rocky Mountains and Great Plains 45.8%
- Central Appalachia 14.5%
- Northern Appalachia 12.5%
- Illinois Basin 12.5%
- Colorado Plateau 7.4%
- Gulf Coast 5.0%

2.3. Mining Methods Review

The data indicates that significant differences exist between the mining operations when reviewed from the perspective of mining method versus average production per mine (Table 2).

[6] This table assumes that all counties in the state of Colorado are in the Colorado Plateau Region, although Moffat and Routt counties, are typically included in the Northern Rocky Mountains and Great Plains region.

	Underground			Surface			Total		
	# of Mines	2012 Production (1,000 tons)	Average Production (1,000 tons)	# of Mines	2012 Production (1,000 tons)	Average Production (1,000 tons)	# of Mines	2012 Production (1,000 tons)	Average Production (1,000 tons)
Southern Appalachia	8	12,570	1,571	38	6,984	184	46	19,554	425
Central Appalachia	333	77,872	234	326	69,279	213	659	147,152	223
Northern Appalachia	85	104,329	1,227	246	22,796	93	331	127,125	384
Colorado Plateau	18	44,886	2,494	8	30,475	3,809	26	75,361	2,898
Gulf Coast	0	0	0	18	51,110	2,839	18	51,110	2,839
Illinois Basin	38	92,493	2,434	41	34,367	838	79	126,860	1,606
Northern Rocky Mtns & Grt Plns	2	10,344	5,172	26	455,320	17,512	28	465,664	16,631
Northwest	0	0	0	1	2,052	2,052	1	2,052	2,052
Western Interior	2	446	223	10	1,144	114	12	1,590	132
TOTAL	**486**	**342,939**	**706**	**714**	**673,529**	**943**	**1,200**	**1,016,468**	**847**

Table 2: Tons Produced per Mine by Region (MSHA)

As shown, average production per mine varies widely, from surface mining operations in the Northern Rocky Mountains and Great Plains Region that produce 17.5 million tons per annum per mine to the surface mines in Northern Appalachia that produce 0.1 million tons per annum per mine. Underground mines range in average production from 0.2 million tons per annum in the Western Interior and Central Appalachian Regions to 5 million tons per annum in the Northern Rocky Mountains and Great Plains Region.

Underground operations are categorized into three mining types: continuous, conventional/other, and longwall. The impacts of the alternatives on underground mining could vary by mining type; therefore, the method of underground production that predominates in each region (Table 3 and Figure 2) was also taken into account in selecting the representative mines.

	2012 Underground Coal Production by Mining Method (1,000 tons)			
	Continuous	Conventional/ Other	Longwall	Total
Southern Appalachia	159	0	12,410	12,570
Central Appalachia	66,370	0	11,502	77,872
Northern Appalachia	22,528	0	81,801	104,329
Colorado Plateau	1,931	0	42,954	44,886
Gulf Coast	0	0	0	0
Illinois Basin	68,625	0	23,868	92,493
Northern Rocky Mtns & Grt Plns	0	0	10,344	10,344
Northwest	0	0	0	0
Western Interior	446	0	0	446
TOTAL	**160,060**	**0**	**182,880**	**342,939**

Table 3: 2012 Underground Coal Production by Mining Method (MSHA)

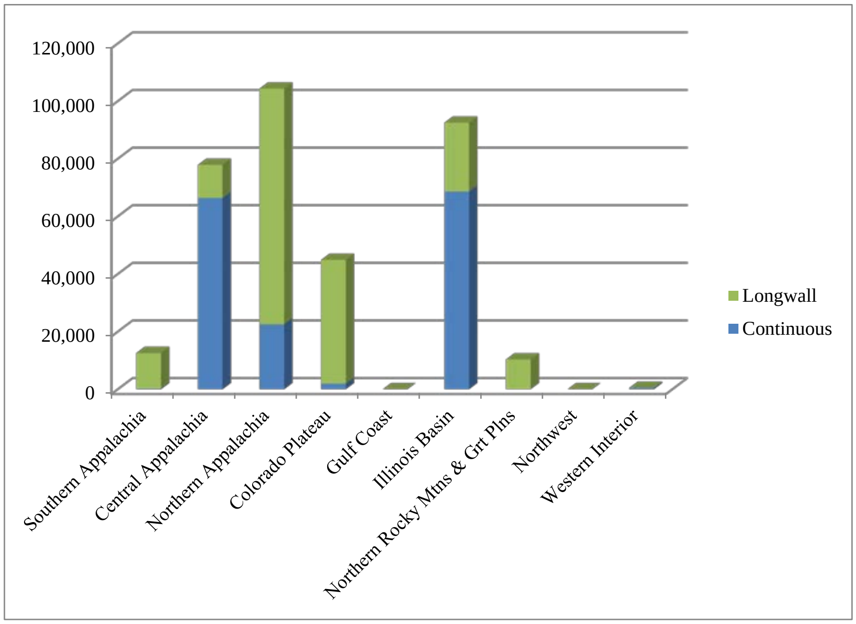

Figure 2: 2012 Underground Coal Production by Mining Type (MSHA)

3. Regional Mining Trends

After evaluating the overall distribution of coal production by region and mine type, each of the major coal producing regions were evaluated to determine the types of mining operations that are representative of that region and what size mine would best represent that mining method. The major coal producing (greater than 5% of total national production) regions include:

- Central Appalachia (14.5%)
- Northern Appalachia (12.5%)
- Colorado Plateau (7.4%)
- Illinois Basin (12.5%)
- Northern Rocky Mountains and Great Plains (45.8%)

Representative mines were also defined for supplementary regions. Supplementary regions are those regions that produce a minor volume of coal from unique mines that cannot be represented by mining operations in the major regions. These regions have unique topography, climate, and geologic conditions that cannot be extrapolated from other regions. These regions include:

- Gulf Coast (5.0%)
- Northwest (0.2%)

The Western Interior Region produced less than 0.5% of the national total, with coal production coming from only 12 mines. Therefore, a representative mine was not developed. Similarly, a representative mine was not developed for the Southern Appalachian Region, since total production in this region is 2% of national production. The effects of the alternatives of the EIS on these regions can be extrapolated from other regions with similar mining methods and characteristics.

Future production trends were taken into account in some regions, most notably in the Illinois Basin, where increases in longwall mining production are anticipated. Overall, thirteen representative mines were defined. The rationale for selecting each mine is described by region below.

3.1. Central Appalachia

Production in Central Appalachia is almost equally divided between surface and underground mining. The number of mines is also divided in a similar manner. In 2012, Central Appalachia contained 333 underground mines that produced 77.9 million tons of coal, in addition to 326 surface mines that produced 69.3 million tons of coal (Table 4). Top producing mines in the region are also equally represented by both underground (U) and surface (S) mines (Table 5).

Central Appalachia Basin Production 2012 (1,000 tons)						
States in Region	Underground		Surface		Total	
	# of Mines	Production	# of Mines	Production	# of Mines	Production
Eastern Kentucky	136	24,116	193	24,624	329	48,740
Virginia	55	12,360	42	6,691	97	19,051
Southern West Virginia	137	40,824	80	37,189	217	78,013
Tennessee	5	573	11	775	16	1,348
TOTAL	**333**	**77,872**	**326**	**69,279**	**659**	**147,152**

Table 4: Central Appalachian Basin Coal Production, 2012 (MSHA)

Method	Mining Operation	Controlling Company	Operator	2012 Production (1,000 tons)
U	Buchanan Mine #1	Consol Energy	Consolidation Coal Company	3,506
S	Holden #22	Arch Coal	Phoenix Coal Mac Mining Inc	3,065
U	Camp Creek Mine	Alpha	Rockspring Development Inc	2,854
S	Twilight MTR Surface Mine	Alpha	Progress Coal	2,677
U	Mountaineer II Mine	Arch Coal	Mingo Logan Coal Company	2,544
S	Hobet 21	Patriot Coal	Hobet Mining, Inc	2,523
U	Pinnacle Mine	Cliffs	Pinnacle Mining Company, LLC	2,433
S	Black Castle Surface Mine	Alpha	Elk Run Coal Company, Inc	2,383
U	American Eagle	Patriot Coal	Speed Mining, Inc	2,266
S	Republic Energy	Alpha	Elk Run Coal Company, Inc	2,249
S	Guyan	Patriot Coal	Apogee Coal Company	2,174
U	No. 1	Booth Energy	Matrix Energy	1,304
U	BC No. 1 Deep	Patriot Coal	Midland Trail Energy	1,275
U	Mine No. 3	Alliance Resource	Excel Mining, LLC	1,238
U	Black Stallion	Patriot Coal	Brody Mining, LLC	1,126
U	Beckley Pocahontas	Arch Coal	ICG Beckley	1,099
S	Mine No. 6	Eagle Hawk Carbon	Coal River Mining, LLC	1,099
S	Combs Branch	Blackhawk Mining	Pine Branch Coal Sales, Inc	1,056
S	East Mac & Nellie	Arch Coal	ICG Hazard	1,037
S	Ewing Fork #1	Alpha	Simmons Fork Mining, Inc	991
			SUBTOTAL	**38,900**
			AVERAGE	**1,945**

Table 5: Top 20 Producing Central Appalachian Mines, 2012 (MSHA)

3.1.1. Central Appalachian Surface Mines

Central Appalachian surface mining is characterized by two vastly different scales of operations. The average surface mine production is approximately 0.2 million tons per annum, but the region also has larger mines, such as Arch Coal's Holden No. 22 operation, which produces over 3 million tons per annum (Table 5 and Figure 3). The scale of mining is typically related to the surface mining method, which falls under one of two primary categories. High production mines typically use area mining methods while low production mines typically use contour mining methods. Therefore, two representative surface mines were chosen to cover the variability in production and mine types for Central Appalachian surface mines.

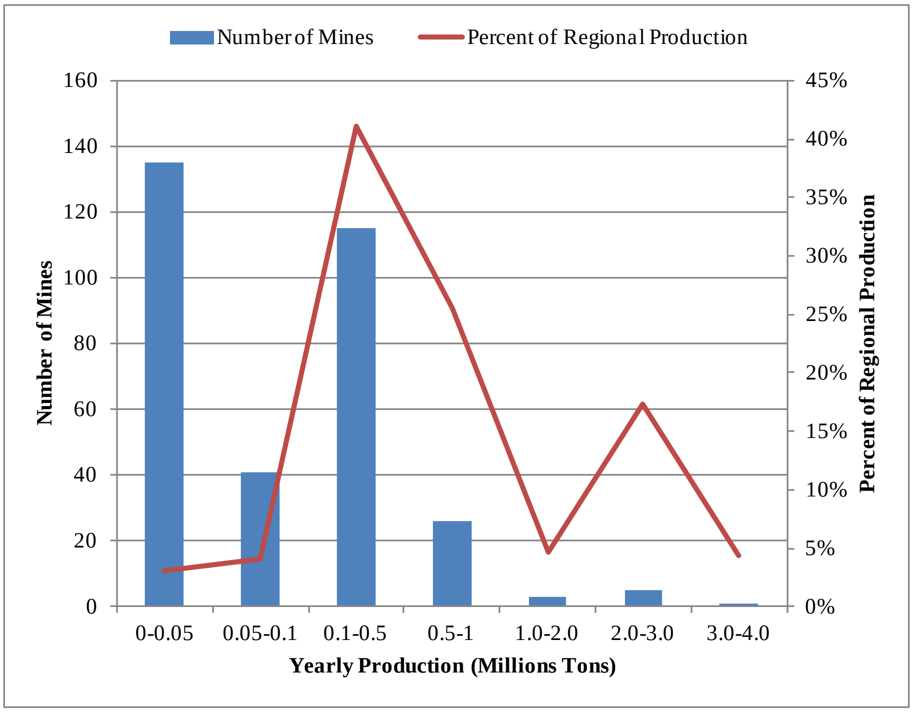

Figure 3: Number of Mines and Yearly Production of Surface Mines in Central Appalachia in 2012 (MSHA)

3.1.1.1. Area Mines

The production records from the top producing Central Appalachian surface mines for the 12 months through the 4th Quarter of 2012 indicate that the seven top producing surface mines produced 16.2 million short tons (23% of the regional total from surface mines), with an average production per mine of 2.3 million tons. Following this analysis, a representative model mine for this region is a surface area mine producing 2.3 million tons per annum. Although large scale surface mining operations in the past have used draglines, the majority of mines currently use loaders, excavators and trucks to move coal and waste rock. Given the decline in the use of draglines, the representative large-scale surface mine will incorporate loaders, excavators and trucks.

3.1.1.2. Contour Mines

The remainder of the region's surface mines that are not represented by area mining are typically contour mines. Ninety-seven percent of surface mines in Central Appalachia produce an average of about 160,000 tons per annum. The majority of surface mines in Central Appalachia produce between 0.1 million and 0.5 million tons per annum or less than 0.05 million tons per annum (Figure 3). Mines producing between 0.1 million to 0.5 tons per annum account for over 40% of the regional surface mine production, while those less than 0.05 million tons per annum only account for less than 5% of the surface production in the region. Therefore, the production range that best represents the region from a population and production standpoint is the 0.1 million to 0.5 million range. As such, the second model surface mine that best represents Central Appalachia has an annual production of 0.5 million tons per year. The 0.5 million ton per year mine is defined as a contour operation to best represent the smaller mines of Central Appalachia. This mine will incorporate loaders and trucks due to the scale of the mining method. Auger and highwall mining equipment can be used for additional coal removal at some Central Appalachian contour mines; however, this type of extraction will not be included in the representative mine to simplify the analysis. Remining was not considered in the design of the representative mines either, due to similar rationale.

3.1.2. Central Appalachian Underground Mines

Underground mining operations in Central Appalachia contribute 8% of the overall coal production in the United States. The underground mines in this region are predominantly room and pillar mining operations that employ continuous mining methods. In fact, 85% of production from underground coal mines in Central Appalachia is from room and pillar mines. The remaining production is primarily from longwall mines, which, unlike the representative mine, are high-production mines. The production is attributed to mines utilizing two mining methods: room and pillar (continuous) and longwall.

The majority of the underground operations in the Central Appalachian Region are small room and pillar mines that produce less than 0.1 million tons per annum, even though the majority of production does not come from mines of this production range (Figure 4). In fact, almost 50% of underground production in this region is accounted for by room and pillar mines that produce between 0.1 million and 0.5 million tons per year. Due to the large number of room and pillar mines, the representative mine for the region was identified as a room and pillar operation. The average production per underground mine in the Central Appalachian Region is 180,000 tons per annum. However, the production for the representative mine was adjusted 0.25 million tons per year from 0.18 million tons per year to better represent the higher production percentage of the mines within the production range of 0.1-0.3 million tons per year. The 0.25 million tons per annum representative mine will be a room and pillar mine that uses continuous mining equipment for all coal production.

Underground mines with production greater than 1 million tons per year account for about 25% of regional underground production. A significant number of these high production mines use the longwall mining method. However, a representative mine was not selected to represent longwall mines for this region. The room and pillar representative mine already represents a significant percentage of the region's production, and the representative longwall mine from the Northern Appalachian Region can be extrapolated to account for the longwall mines in this region.

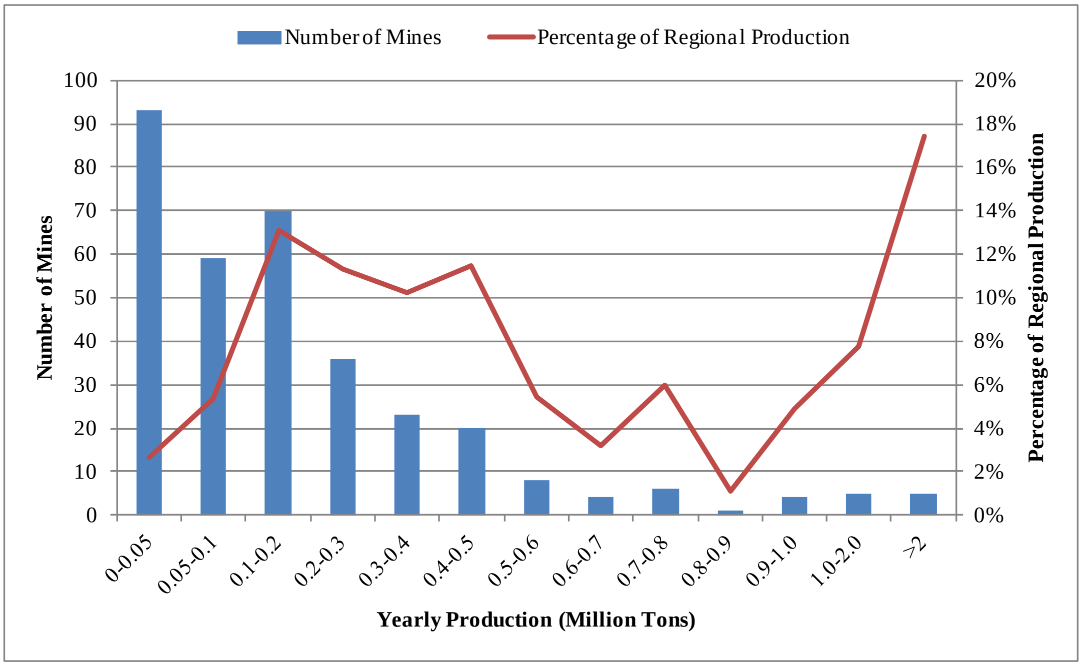

Figure 4: Number of Mines and Yearly Production of Underground Mines in Central Appalachia in 2012 (MSHA)

3.2. Northern Appalachia

Production in the Northern Appalachian Region is dominated by underground mining (Table 6). While the region produced 12.5% of the nation's coal in 2012, 10% of national production came from Northern Appalachian underground mining alone. This is the largest underground production share of any region. Approximately 78% of Northern Appalachia's underground production comes from longwall mining. Thus, the representative underground mine from this region is a longwall mine, representative of the major producing mines in the region.

Northern Appalachia Basin Production 2012 (1,000 tons)						
States in Region	Underground		Surface		Total	
	# of Mines	Production	# of Mines	Production	# of Mines	Production
Maryland	3	770	20	1,581	23	2,351
Ohio	10	19,206	28	8,610	38	27,816
Pennsylvania	48	41,822	182	10,088	230	51,910
Northern West Virginia	24	42,531	16	2,518	40	45,049
TOTAL	**85**	**104,329**	**246**	**22,796**	**331**	**127,125**

Table 6: Northern Appalachian Basin Coal Production, 2012 (MSHA)

Northern Appalachia also has surface mines, but these are small operations that do not contribute significantly to the overall production in the region. However, the surface mines are unique to the region; therefore, a representative mine was identified to account for them.

3.2.1. Northern Appalachian Surface Mines

A representative surface mine was defined for Northern Appalachia due to the significant number of surface mines in the region. Northern Appalachian surface mining contributed 2.2% of national coal production in 2012 with 23 million tons. However, this production came from 246 surface mines, accounting for 34% of the surface coal mines in the United States.

The average production for surface mining operations in Northern Appalachia was 93,000 tons per mine in 2012. This average is influenced by the large number of surface mines that produced less than 0.05 million tons per year; these mines account for 11% of the region's surface mine production (Figure 5). The largest production volume comes from mines that produce 0.1 million to 0.3 million tons per annum and 0.8 million to 1 million tons per annum. Approximately 50 mines compose the smaller production range, while only four mines account for the production in the higher of the two ranges. Therefore, the representative surface mine falls in the range between 0.1 million and 0.3 million tons per year at an annual production of 0.2 million tons.

The representative operation is a surface contour mine, which is consistent with prevailing practices.

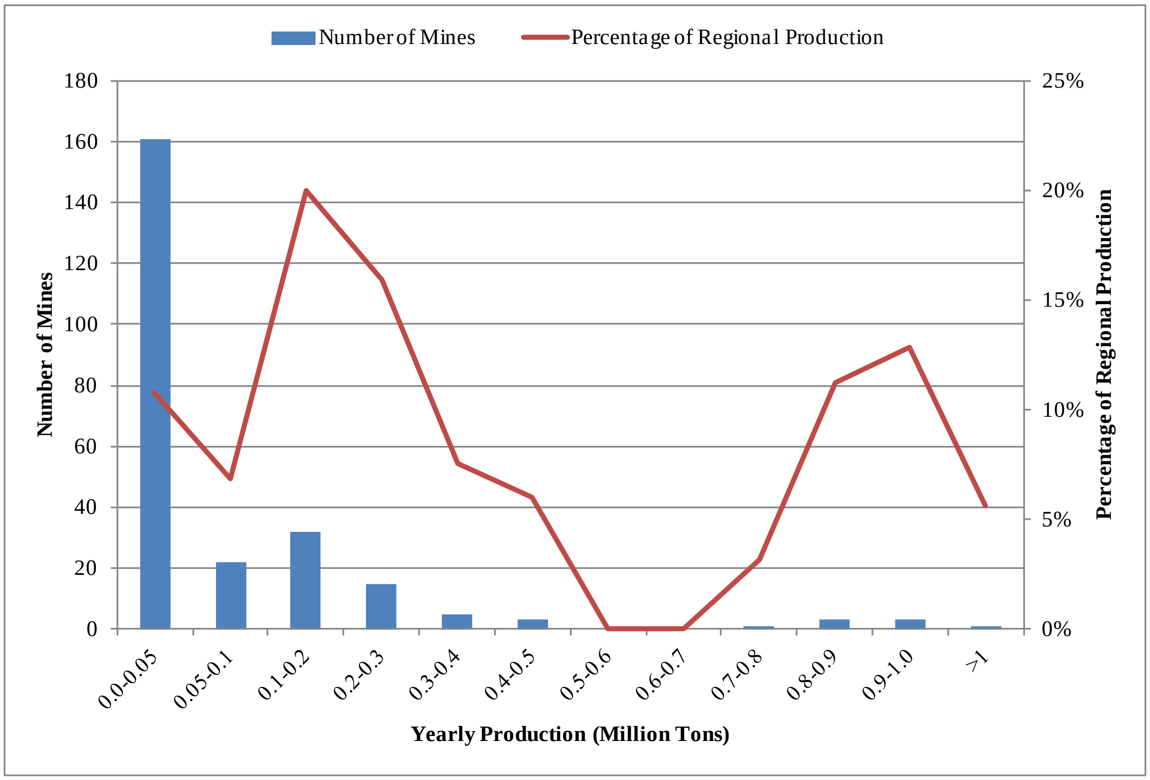

Figure 5: Number of Mines and Yearly Production of Surface Mines in Northern Appalachia in 2012 (MSHA)

3.2.2. Northern Appalachian Underground Mines

Production records from the top producing Northern Appalachian mines show that 21 underground mines produced greater than 1 million tons per year. In total, these mines produced 90 million short tons in 2012, with an average production per mine of over four million tons per annum (Table 7). Most of these mines are longwall operations; however, the region also has a significant number of room and pillar operations.

The majority of underground mines populating the Northern Appalachian Region produce less than one million tons per annum, accounting for only 13% of underground production in the region (Figure 6).

The lower production underground mines are room and pillar operations; therefore, results from the Central Appalachian underground mine can be extrapolated to these operations.

The majority of the production in the Northern Appalachian Region comes from the small number of mines that produce over one million tons per year. Most of these high production mines are longwall operations; therefore, the longwall mining operations have the greatest influence on production in the region. As a result, the representative mine selected for Northern Appalachia is a longwall operation. The representative longwall operations has an annual production of 4.6 million tons.

Method	Mining Operation	Controlling Company	Operator	2012 Production (1,000 tons)
U	Bailey Mine	Consol Energy	Consol PA Coal	10,123
U	Enlow Fork Mine	Consol Energy	Consol PA Coal	9,459
U	McElroy Mine	Consol Energy	McElroy Coal Company	9,400
U	Century Mine	Murray Energy	American Energy Corporation	8,447
U	Cumberland Mine	Alpha	Cumberland Coal Resources LP	6,425
U	Loveridge No. 22	Consol Energy	Consolidation Coal Company	5,869
U	Powhatan No. 6 Mine	Murray Energy	The Ohio Valley Coal Company	5,768
U	Shoemaker Mine	Consol Energy	Consolidation Coal Company	5,316
U	Robinson Run No. 95	Consol Energy	Consolidation Coal Company	4,992
U	Emerald Mine #1	Alpha	Emerald Coal Resources LP	4,384
U	Federal #2	Patriot Coal	Eastern Associated Coal Corp	4,045
U	Blacksville No. 2	Consol Energy	Consolidation Coal Company	3,231
U	Mountain View	Alliance Resource	Mettiki Coal LLC	2,285
U	Tunnel Ridge Mine	Alliance Resource	Tunnel Ridge LLC	2,001
U	Buckingham Mine #6	Buckingham Coal	Buckingham Coal Company	1,703
U	4 West Mine	Mepco	Dana Mining Company of PA, Inc	1,496
S	Snyder Mine	Oxford Mining	Oxford Mining	1,287
U	Hopedale	Rhino Energy	Hopedale Mining	1,159
U	Prime No. 1	Mepco	Dana Mining Co., Inc	1,099
U	Poplar Ridge No. 1 Deep	Alpha	Brooks Run Mining Company, LL	1,069
U	Buckingham Mine #7	Buckingham Coal	Buckingham Coal Company	1,059
U	Sentinel Mine	Arch Coal	Wolf Run Mining	1,032
			SUBTOTAL	**91,649**
			AVERAGE	**4,166**

Table 7: Top 22 Producing Northern Appalachian Mines, 2012 (MSHA)

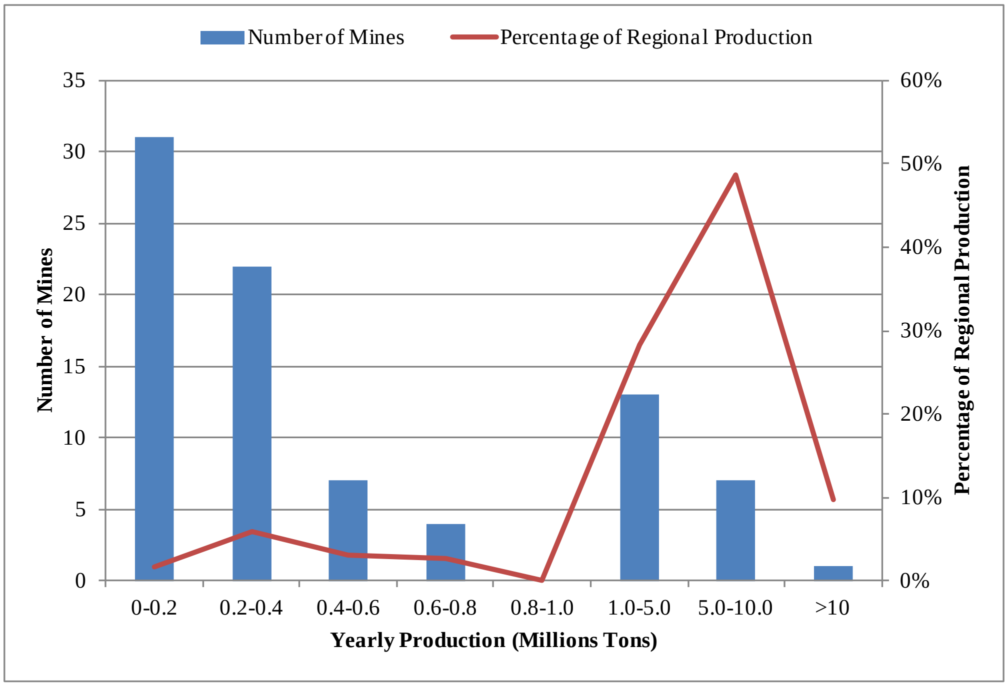

Figure 6: Number of Mines and Yearly Production of Underground Mines in Northern Appalachia in 2012 (MSHA)

3.3. Colorado Plateau

The Colorado Plateau region produced approximately 75.3 million tons of coal in 2012, equal to 7.4% of coal production in the United States. Underground mining production made up 60% of the region's production (Table 8), while surface mines produced the remaining 40% of regional production. Thus, the Colorado Plateau region will be represented by an underground model mine and a surface model mine.

Colorado Plateau Production 2012 (1,000 tons)						
States in Region	Underground		Surface		Total	
	# of Mines	Production	# of Mines	Production	# of Mines	Production
Arizona	0	0	1	7,493	1	7,493
Colorado	9	23,649	3	4,920	12	28,569
New Mexico	1	4,960	3	17,492	4	22,452
Utah	8	16,277	1	570	9	16,847
TOTAL	**18**	**44,886**	**8**	**30,475**	**26**	**75,361**

Table 8: Colorado Plateau Coal Production, 2012 (MSHA)

3.3.1. Colorado Plateau Surface Mines

Surface mines in the Colorado Plateau Region vary widely in size (Figure 7). The average production for surface mining in the region was 3.8 million tons in 2012, while median production was 2.3 million tons. The majority of production from surface mines in the region comes from New Mexico, where two of the region's top three producing mines are located, one of which produces over eight million tons per year. Due to the variance in production per mine, the best representation of production from surface mines in the region is the yearly average. Therefore, representative mine for the region has an annual production of 4.1 million tons, which was the average production by surface mines in the region in 2010.

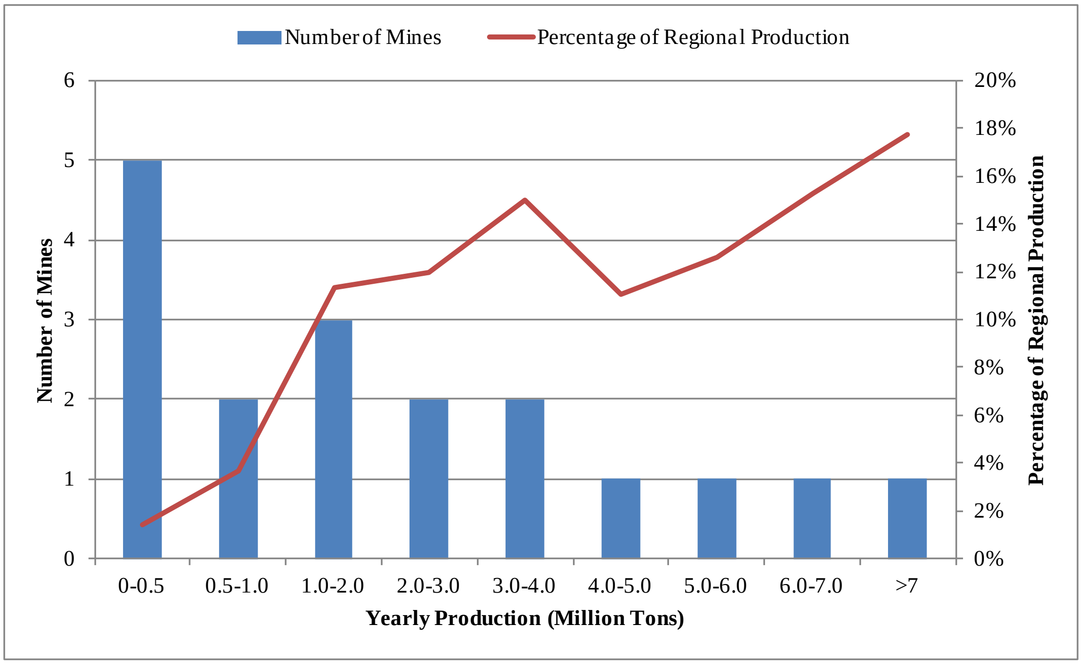

Figure 7: Number of Mines and Yearly Production of Underground Mines in the Colorado Plateau Region in 2012 (MSHA)

3.3.2. Colorado Plateau Underground Mines

Average underground mine production in the Colorado Plateau was 2.5 million tons in 2012. Smaller mines influence this average significantly while contributing relatively little to total production with 39% of the underground mines in the basin producing 8% of the underground coal. Furthermore, an assessment of top producing Colorado Plateau mines indicates that the 11 underground mines that produced greater than 1 million tons in 2012 produced 42.3 million short tons, which is 94% of the total underground mine production for the region (Table 9). These mines have an average production per mine of 3.8 million tons, which better represents the majority of coal mines in the region. The representative underground mine in the Colorado Plateau produces 3.7 million tons.

The primary underground production in the Colorado Plateau Region is accounted for by longwall mines; therefore, the representative model mine is defined as a longwall mine.

Method	Mining Operation	Controlling Company	Operator	2012 Production (1,000 tons)
S	El Segundo	Peabody	Peabody New Mexico	8,567
U	Foidel Creek	Peabody	Twentymile Coal	7,975
S	Navajo	BHP	Navajo Coal Company	7,619
S	Kayenta	Peabody	Peabody Western Coal Company	7,493
U	West Elk	Arch Coal	Mountain Coal Company	6,852
U	Sufco	Arch Coal	Canyon Fuel Company	5,650
U	San Juan UG	BHP	San Juan Coal Company	4,960
U	Bowie #2	Bowie Resources	Bowie Resources	3,430
U	Deer Creek	Pacificorp	Energy West Mining	3,295
U	Elk Creek	Oxbow Carbon	Oxbow Mining	2,958
U	West Ridge	Murray Energy	West Ridge Resources	2,409
S	Trapper	Trapper Mining	Trapper Mining	2,301
S	Colowyo	Western Fuels	Colowyo Coal Company	2,265
U	Skyline	Arch Coal	Canyon Fuel Company	1,894
U	Deserado	Deseret G & T	Blue Mountain Energy	1,673
U	Dugout Canyon	Arch Coal	Canyon Fuel Company	1,516
S	Lee Ranch	Peabody	Peabody New Mexico	1,306
			SUBTOTAL	**72,166**
			AVERAGE	**4,245**

Table 9: Top 17 Producing Colorado Plateau Mines, 2012 (MSHA)

3.4. Gulf Coast

Surface mining in the Gulf Coast region accounts for 5% of the total production in the United States. Most of the mining in the region occurs in Texas, which had 12 mines producing over 44 million tons per year in 2012 (Table 10). The mining is unique in that the coal produced in the region is lignite, rather than bituminous coal. Even though these mines are not major contributors to the nation's coal production, they have a significant effect on the associated power plants, which are situated near the mines. Furthermore, the distinctive geologic and topographic characteristics of this region do not easily allow for the extrapolation of impacts from other regions. Thus, a representative surface mine was established for the Gulf Coast region. The mine is a surface area mine utilizing draglines, reflecting typical practices.

Gulf Coast Production 2012 (1,000 tons)						
States in Region	Underground		Surface		Total	
	# of Mines	Production	# of Mines	Production	# of Mines	Production
Louisiana	0	0	2	3,979	2	3,979
Mississippi	0	0	1	2,953	1	2,953
Texas	0	0	15	44,178	15	44,178
TOTAL	**0**	**0**	**18**	**51,110**	**18**	**51,110**

Table 10: Gulf Coast Coal Production, 2012 (MSHA)

Average and median production for the region in 2012 totaled 3.4 million tons and 3.1 million tons, respectively. Additionally, 51% of the region's production in 2012 came from surface mines producing between three and five million tons per year (Figure 8). The representative mine has an annual production of 3.3 million tons per year. This number is based on the average production per mine in 2010; however, it is consistent with the average production in 2012.

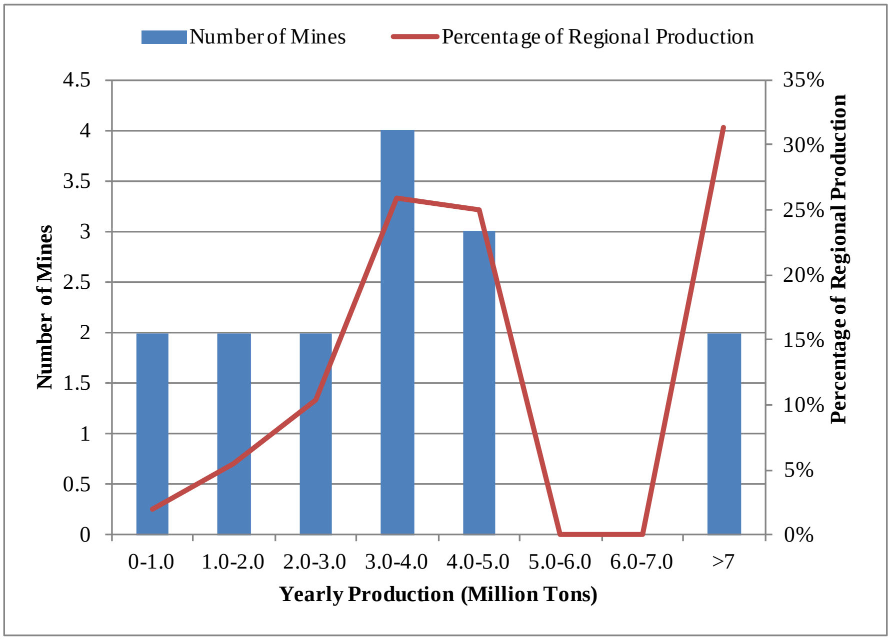

Figure 8: Number of Mines and Yearly Production of Gulf Coast Mines in 2012 (MSHA)

3.5. Illinois Basin

Coal production in the Illinois Basin is dominated by underground mining, with 73% of production coming from underground mines and only 27% from surface mining (Table 11). The majority of the highest producing mines are underground operations (Table 12). Continuous room and pillar mining constitutes the majority of underground mining in the region, however, five longwall operations were active in the Illinois Basin in 2012. Additionally, several additional longwall mines are expected to be opened over the next few years. The Illinois Basin also has a number of surface mining operations, which have design characteristics that are unique to that region. Therefore, three representative mines were designed for the Illinois Basin: a continuous room and pillar underground mine, a longwall underground mine, and a surface area mine.

Illinois Basin Production 2012 (1,000 tons)						
States in Region	Underground		Surface		Total	
	# of Mines	Production	# of Mines	Production	# of Mines	Production
Illinois	15	42,837	9	5,649	24	48,486
Indiana	9	15,565	19	20,766	28	36,330
Western Kentucky	14	34,091	13	7,952	27	42,043
TOTAL	**38**	**92,493**	**41**	**34,367**	**79**	**126,860**

Table 11: Illinois Basin Coal Production, 2012 (MSHA)

Method	Mining Operation	Controlling Company	Operator	2012 Production (,000 tons)
U	River View	Alliance Resource	River View Coal	8,622
S	Bear Run	Peabody	Black Beauty	8,071
U	Mach #1	Foresight Energy	Mach Mining	7,528
U	New Era	Murray Energy	American Coal	5,642
U	Cardinal	Alliance Resource	Warrior Coal	5,236
U	Sugar Camp A	Foresight Energy	M-Class	4,690
U	Highland #9	Patriot Coal	Highland Mining	3,951
U	New Future Mine	Murray Energy	American Coal	3,642
U	Gibson North	Alliance Resource	Gibson County Coal	3,432
U	Dotiki	Alliance Resource	Webster County	3,363
U	Elk Creek	Alliance Resource	Hopkins County	3,069
U	Carlisle	Sunrise Coal	Sunrise Coal	3,008
S	Equality Boot	Armstrong Coal	Armstrong Coal	2,868
U	Lively Grove	Prairie State	Prairie State	2,819
U	Gateway	Peabody	Peabody Midwest	2,766
U	Francisco UG	Peabody	Peabody Midwest	2,756
U	Oaktown #1	Vectren	Black Panther Mining	2,754
U	Pattiki #2	Alliance Resource	White County Coal	2,380
U	Deer Run	Foresight Energy	Patton Mining	2,365
S	Somerville Central	Peabody	Black Beauty	2,347
U	Paradise #9	Murray Energy	KenAmerican	2,251
U	Viper	Arch Coal	ICG Illinois	2,108
U	Willow Lake	Peabody	Big Ridge	2,086
U	Prosperity	Vectren	Five Star	2,072
			SUBTOTAL	**89,829**
			AVERAGE	**3,743**

Table 12: Top 24 Producing Illinois Basin Mines, 2012 (MSHA)

3.5.1. Illinois Basin Surface Mine

Surface coal mines in the Illinois Basin Region are typically located in flat topographic conditions. These conditions warrant the use of "box cuts" and final cut pit impoundments as a part of the mining method. With the significant surface coal production in the Illinois basin a model mine to represent this mining was created. In 2012, the average production for all 41 Illinois Basin surface mines was 0.8 million tons. However, 31% of the production in 2012 came from mines producing between 1 and 2 million tons, and 11% of the production in 2012 came from mines producing less than 0.5 million tons (Figure 9). In order to reflect the largest share of production, the representative surface mine in the Illinois Basin produces 1 million tons per year.

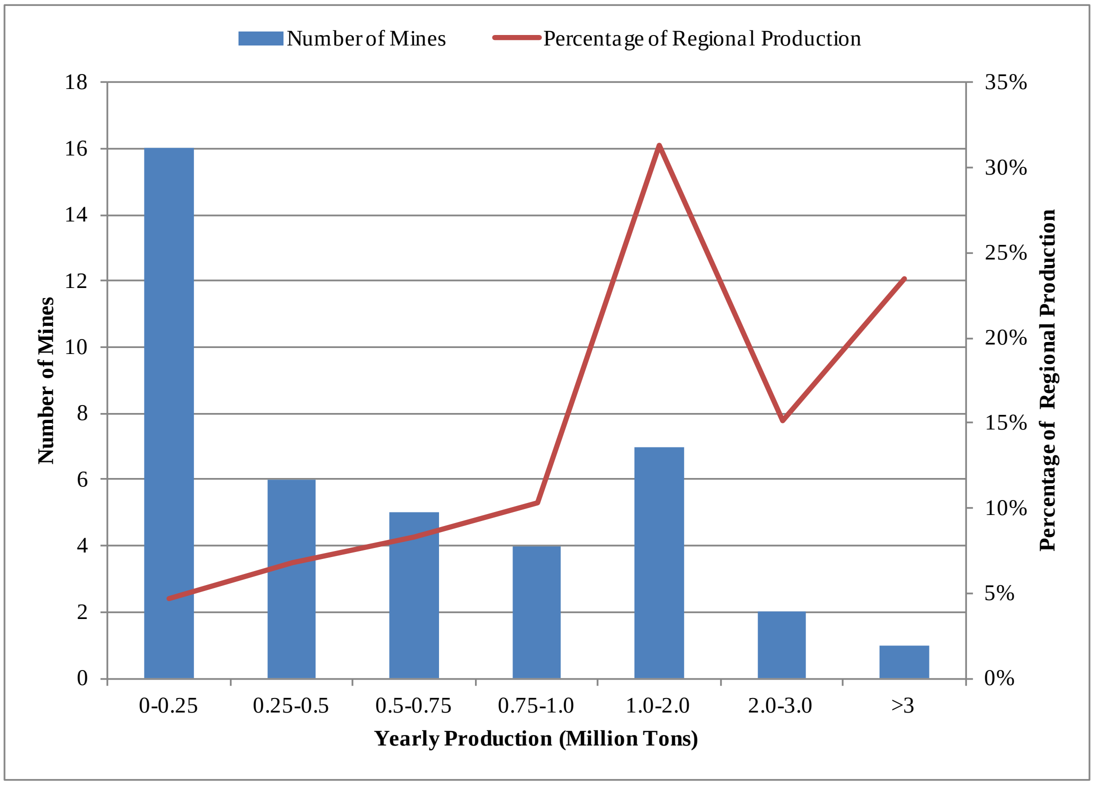

Figure 9: Number of Mines and Yearly Production of Surface Mines in the Illinois Basin in 2012 (MSHA)

3.5.2. Illinois Basin Underground Mines

The Illinois Basin has a significant number of room and pillar and longwall operations. Due to the unique geology and mining characteristics of the region, representative mines were chosen for both room and pillar and longwall operations.

3.5.2.1. Room and Pillar Mines

The majority of underground mines in the Illinois Basin Region produced between 2 and 3 million tons in 2012 (Figure 10). The median and average production from those mines is approximately 2.1 million tons per annum. Therefore, the representative Illinois Basin room and pillar underground mine produces 2.1 million tons per year.

3.5.2.2. Longwall Mines

Five longwall mines operated in the Illinois Basin Region in 2012, with several more longwall operations expected to be permitted in the next few years. The average longwall production in 2012 was 4.8 million tons, but recent reports indicate that future Illinois longwall operations will produce at least 6 million tons per annum.[7] Thus, the representative longwall mine for the Illinois Basin produces 6 million tons per year.

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[7] Recent expansion of longwall mining in Illinois shows that additional longwall operations may push this average production higher. The Deer Run Mine, which is part of the Hillsboro Complex, is expected to produce 8-10 million tons per year (Coal Age, "NRP Completes Third Acquisition of Coal Reserves at Deer Run Mine" (November 17, 2010), *available at*: http://www.coalage.com/index.php/news/latest/730-nrp-completes-third-acquisition-of-coal-

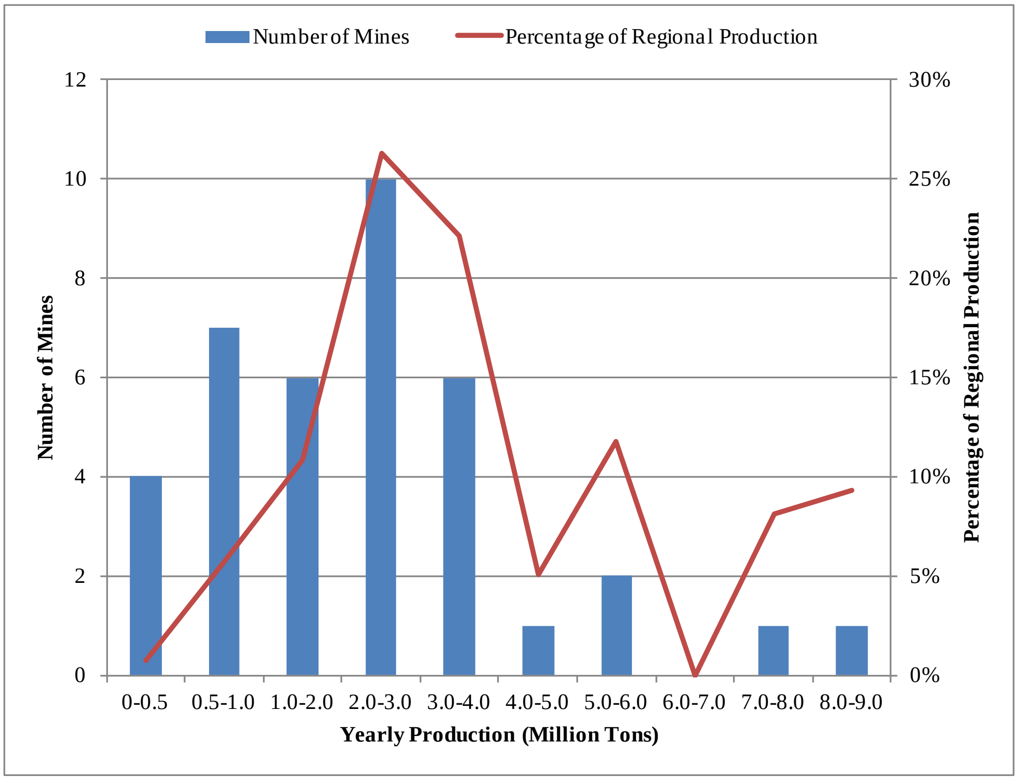

Figure 10: Number of Mines and Yearly Production of Underground Mines in the Illinois Basin in 2012 (MSHA)

3.6. Northern Rocky Mountains and Great Plains

The majority of production in the Northern Rocky Mountains and Great Plains Region is attributed to Wyoming surface mines located in the Powder River Basin. These mines are therefore the best representation of the mine sizes found in this region. Thus the average production of the top producing mines in the Powder River Basin was used to identify the annual production for the representative mine. The representative mine for the region has an annual production of 27.2 million tons. In 2010, the average production for the Powder River Basin was 27.2 million tons. This annual production tonnage falls between the fourth and fifth highest producing mines in the region (Table 14). The large-scale area surface mines in the region typically use a combination of draglines, excavators and loaders with trucks to mine the coal. Therefore, the representative mine uses a combination of draglines and loader with trucks.

A representative underground mine was not defined for the Northern Rocky Mountains and Great Plains Region since the underground mines in the region account for less than 1% of the region's total annual production.

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reserves-at-deer-run-mine.html). A recent *Coal News* publication (Volume 8, Number 21, November 2011) indicates that four longwall mines have submitted permit applications for new or expanded operations, with three of these mines, Deer Run, White Oak, and Sugar Camp, each expected to produce 7.0 million tons per year, and the fourth, Lively Grove, expected to produce 6.0 million tons per year.

Northern Rocky Mountains and Great Plains Production 2012 (1,000 tons)						
States in Region	Underground		Surface		Total	
	# of Mines	Production	# of Mines	Production	# of Mines	Production
Montana	1	5,708	5	30,986	6	36,694
North Dakota	0	0	4	27,529	4	27,529
Wyoming	1	4,637	17	396,805	18	401,442
TOTAL	**2**	**10,344**	**26**	**455,320**	**28**	**465,664**

Table 13: Northern Rocky Mountains and Great Plains Coal Production, 2012 (MSHA)

Surface Mining Operation	2012 Production (1,000 tons)
NARM Complex	107,639
Black Thunder	93,083
Cordero	39,205
Antelope	34,316
Belle Ayr	24,228
Eagle Butte	22,467
Buckskin	18,059
Spring Creek	17,199
Caballo	16,841
Rawhide	14,721
Rosebud	8,018
Coal Creek	7,564
Dry Fork	6,007
Wyodak	4,246
Decker	2,758
Absaloka	2,714
SUBTOTAL	419,066
AVERAGE	26,192

Table 14: Top Producing Powder River Basin Surface Mines, 2012 (MSHA)

3.7. Northwest

The Northwest Region has one operating surface mine, located in Alaska. The mine produced 2.1 million tons of coal in 2012, which was less than 0.5% of the total coal production in the United States. However, a model mine was warranted for this region due to the unique climate, topography, geology, and hydrology. Any effects of the Stream Protection Rule could not easily be extrapolated from other regions to this region. The model mine is based upon the currently operating surface mine and utilizes similar topography and geology that occurs in that coal bearing area. To reflect a mine size similar to the currently operating Alaska mine, the representative mine for this region has a production of 2 million tons per year.

3.8. Summary

The 13 mines defined for the model mine analysis are representative of the geography and mining methods associated with the coal producing regions in the United States. The representative mines are summarized as follows:

- The three representative mines in the **Central Appalachian Region** capture the majority of that region's production. Variations in surface mining practices in the region can be analyzed using the two sizes of surface mines operating with **area** and **contour** mining methods. While the **continuous room and pillar** representative mine fails to capture the longwall and conventional room and pillar mining in the region, production from longwall and conventional mines is minimal and impacts can be extrapolated from other regions. In addition, remining operations were not designed as part of this analysis since the mining type, scale, efficiency, and pre-mining impacts are site specific and highly variable depending on the operation.
- **Underground longwall** and **contour** representative mines were defined for the **Northern Appalachian Region**. The representative surface mine can be used to describe the general effects on all surface mining in the region, while the representative underground mine will only account for any effects that may occur on longwall operations. Production from continuous or conventional room and pillar underground operations in the region is not significant enough to justify an additional representative mine analysis. The effects on continuous underground operations can be estimated from the representative underground continuous operation in the Central Appalachian Region.
- The **Colorado Plateau Region** has both **surface** and **underground** representative mines. Over 96% of the underground production comes from longwall mining operations, which the selected representative underground mine for this region. The representative surface mine is reflective of practices in New Mexico, the source of over 57% of the surface mine production in the region.
- The **Gulf Coast Region** features only larger **surface** mines that extract lignite. The representative mine reflects 100% of this production.
- The **Illinois Basin** has three representative mines, a **surface** mine, **underground longwall** operation, and **underground room and pillar** operation using continuous methods. These are representative of each of the mining methods in the region.
- Coal produced in the **Northern Rocky Mountains and Great Plains Region** comes primarily from **surface** mines in the Powder River Basin. Therefore, the representative mine for the region was determined using production numbers from the Powder River Basin mines.
- The **Northwest Region** representative **surface** mine is based upon the only currently operating mine in the region; therefore, it represents 100% of current production.

Table 15 depicts the actual percentages of production represented by the representative mines. As shown, the representative mine analysis directly reflects practices at mines producing 97% of all coal in the United States.

Representative Mine Description		Representative Mine Annual Production (million tons)	2012 U.S. Production by Method and Region (million tons)	
			Surface	Underground
Central Appalachia	Surface Area	2.3	69	
Central Appalachia	Surface Contour	0.5		
Central Appalachia	Underground Room and Pillar	0.25		78
Northern Appalachia	Underground Longwall	2.0		104
Northern Appalachia	Surface Contour	0.2	23	
Colorado Plateau	Underground Longwall	3.0		45
Colorado Plateau	Surface Area	3.3	30	
Gulf Coast	Surface Area	3.3	51	
Illinois Basin	Underground Room and Pillar	2.1		92
Illinois Basin	Underground Longwall	6.0		
Illinois Basin	Surface Area	1.0	34	
Northern Rocky Mtns & Grt Plns	Surface Area	27.2	455	
Northwest (Alaska)	Surface Area	2.0	2	
Total U.S. 2012 Production Represented (million tons)			**665**	**320**
Percent of Total U.S. 2012 Production Represented by Model Mines			**98.8%**	**93.2%**

Table 15: Typical Mines Representation of National Production (MSHA)

Some mining operations in various regions are not represented by the representative mines; however, the analysis of similar representative mines in other regions can be used to extrapolate possible impacts to those mines that are not directly represented. For example:

- The effects of the alternatives on longwall mining in Southern Appalachia (Alabama), where overburden thickness can reach up to 2000 feet, can be inferred from the analysis of longwall mining in Northern Appalachia. The overburden is shallower in Northern Appalachia; therefore, it can be assumed that the probability for material damage in Alabama would be less than in Northern Appalachia.
- The impacts on North Dakota lignite mines can be inferred from the analysis of the Northern Rocky Mountains and Great Plains surface mine, which is of a similar scale as what would be common in North Dakota, and by the Gulf Coast surface mine, which also mines lignite.
- The effects of remining, which typically occur in the Appalachian Basin, can be extrapolated from the representative mines in this region.
- The effects of Illinois Basin surface mines can be extrapolated to the Western Interior surface mines. The Western Interior surface mines tend to be somewhat smaller in scale than the representative mines in the Illinois Basin; however, similar impacts to mine design from the Stream Protection Rule are expected.

4. MODEL MINES

Models mines have been developed using the representative production rates of each region. The model mine methodology incorporates design elements unique to each action alternative of the Environmental Impact Statement. Therefore, the model mines are designed to assess the primary effects of each action alternative of the EIS but cannot cover conditions that may be specific to an individual mine. The following steps describe the model mine design methodology:

1) **Choose representative permits to define model mine attributes -** The model mine analysis uses design elements from currently operating mines. Therefore, active mine permits with similar annual production tonnages to the regional representative tonnages were chosen. The permits were used to define coal seam thicknesses, life of mine coal reserves, depth of cover and stripping ratios, stream impacts, mine impact acreage, reclamation plans, and other pertinent information related to each operation. The geographic location of each active permitted operation was also used to identify a realistic mining location for each model mine. The proximity of the model mines to the associated permits ensured the terrain of the model mine operation mirrored the permits.
2) **Download digital terrain model (DTM) of nearby terrain -** A digital terrain model of each model mine location was downloaded from the USGS Seamless Server[8]. The models were imported into Manifold® System for conversion to topographic contours[9].
3) **Contour DTM -** For terrain modeling purposes, Manifold was used to transform the elevations of the surfaces from SI units to U.S. customary units and contour the surface at specified elevation intervals. The contours are essential to surface modeling and calculating material volumes.
4) **Generate core holes -** Core holes were created and placed in the model using Carlson Software with AutoCAD®[10]. The core data was based on the mining method and coal seam depth and thickness described in the representative active permits that were used to define the model mine attributes.
5) **Create coal seams -** The core hole data was used to model the coal geology for each mine.
6) **Generate streams -** Streams were generated for each model mine using the surface topography. This process included delineation of the ephemeral reaches of streams. By definition, ephemeral streams flow "only in direct response to precipitation…and which has a channel bottom that is always above the local water table[11]." Therefore ephemeral streams do not have a groundwater component and can be approximated using surface drainage areas. The drainage areas for the model mines were back-calculated from the representative permits by estimating the area of drainage required for streams in the permit area to form a channel. These areas were then averaged and the average drainage area was used to delineate the upper reaches of streams for each model mine using Manifold. This process was dependent on

[8] http://seamless.usgs.gov/website/seamless/viewer.htm (now the National Map)

[9] Manifold® System 8.0 Professional Edition Build 8.0.24.0 with Manifold Surface Tools.

[10] Carlson Software 2014 Build 130924 with AutoCAD® 2013 SP2 Build G.204.0.0.

[11] Code of Federal Regulations, Title 30 - Mineral Resources, Chapter VII - Office of Surface Mining Reclamation and Enforcement, Department of the Interior, Subchapter A – General, Part 701 – Permanent Regulatory Program, Subpart 5 – Definitions. (Sept 27, 2013)

available data in the representative permits. The National Hydrography Dataset[12] (NHD) of the National Map[13], a source for surface water data for the United States, was used as a supplement to the computer generated streams. It could not be used as the sole source of streams due to its lack of information on ephemeral stream reaches and variability in data quality.

7) **Define stream types -** Next, the start of each intermittent stream was determined. This point differed depending on the location of the model mine and the alternative. The intermittent streams were defined by a drainage area, location relative to the down-dip side of a coal seam (coal seams act as groundwater aquifers), aerial images, or the one-square mile drainage definition[14] in the Code of Federal Regulations. Stream classifications are approximate due to the seasonal and geological effects on streams that could not be modeled.
8) **Create mine boundary -** The mineral removal area was then generated for each model mine. A number of factors were assessed to determine the extent of the mineral removal area. First, the representative permits were reviewed to determine the life of mine production. Then, a mineral removal area was selected based on the tonnage of coal per acre and other topographic limitations. The mine areas were subject to the terrain, mining type, and coal seam geometry. For instance, seam outcrop delineations, or the intersection of the coal seam and the surface topography, were used to delineate parts of the mining area for almost all of the model mines in the Appalachian Regions. Other areas with open pit surface mining used boundaries that mimicked the representative permit. Underground mining boundaries in regions other than the Colorado Plateau and Central Appalachia were dependent on mining type due to the requirements of the mining methods. It was assumed that the location of each mine is on virgin land without any residents or previous mining impacts.
9) **Calculate coal tonnage, stripping ratios, etc.** – Mineral removal areas were applied to the model mine terrain and the coal tonnage within the mining area was calculated. This process was repeated until the tonnage within the model mine mineral removal area was similar to the life of mine tonnage associated with the representative permit. The stripping ratios and coal unit weights were also cross-referenced with the representative permits to ensure the model mines accurately represent the regions.
10) **Create postmining topography -** With the mineral removal area defined, the tonnage of spoil (overburden that will be removed to access the coal) is also defined. Spoil swells when it is blasted and removed; therefore, a swell factor was applied to all surface mining operations. In the surface model mine analysis, a 25% swell factor was assumed for all spoil. Central Appalachia is a unique region, where the spoil swells to a volume that cannot be placed completely back within the mined area. The steep topography also limits the placement of material for stability reasons. In this case, the excess spoil is placed outside of the mineral removal boundary in valley fills. The valley fills are designed according to industry and regulatory standards, depending on the alternative.

[12] National Hydrography Dataset, USGS

[13] http://nationalmap.gov/viewer.html (USGS)

[14] Code of Federal Regulations, Title 30 - Mineral Resources, Chapter VII - Office of Surface Mining Reclamation and Enforcement, Department of the Interior, Subchapter A – General, Part 701 – Permanent Regulatory Program, Subpart 5 – Definitions. (Sept 27, 2013)

11) **Calculate stream impacts -** With the final mine designs complete, the stream impacts due to all facets of the model mines under each alternative are quantified.

4.1. Central Appalachia

The Central Appalachian Region includes three model mines: a surface area mine, a surface contour mine, and an underground room and pillar mine. The digital elevation models used to develop the topographic contours for the mines in this region has a resolution of approximately three meters; therefore, the steep topography could be contoured with relative accuracy. Both surface mines were delineated using the same location, assuming the land was untouched for each operation. The underground mine model topographic contours were delineated from a digital elevation model from another nearby location with similar topography.

Streams were delineated in the Central Appalachian Region based on a published document on stream channels in eastern Kentucky[15] and current permits. Based on the sources, ephemeral stream reaches in Central Appalachia require an average of 14.5 acres before surface sheet flow channelizes. At this point ephemeral streams begin. This drainage requirement was used to delineate all stream reaches for the Central Appalachian model mines. In order to determine the point where the streams become intermittent (include a groundwater component), a similar method was used. Due to the difficulty in modeling seasonal groundwater changes, intermittent streams were identified using drainage area and coal seam outcrop location. Coal seams behave as aquifers; therefore, the down-dip side of the lowest mined coal seam was used to mark the end of the ephemeral stream and the beginning of the intermittent stream. On the up-dip side of the coal seam, intermittent points were based on a drainage area of 19.8 acres. This number comes from the aforementioned stream channel study.

4.1.1. Central Appalachian Surface Model Mines

The surface area model mine is a multiple seam mining operation designed to produce 2.3 million tons of coal per annum at an overall mining ratio of 16 bank cubic yards of overburden per ton of coal. The model mine has a life of 16 years, assuming constant production over the time frame. The surface contour mine is designed to produce 0.5 million tons per year for 10 years.

4.1.1.1. Surface Area Mine

The surface area model mine in Central Appalachia is typical of larger surface mines in the region. The mine design is consistent with the current EPA guidance document, West Virginia AOC+ policy, and the 2008 stream buffer zone fill minimization requirements. Regardless of alternative, the mineral removal area includes 37 million tons of coal resource with 738 million loose cubic yards of spoil material. The full volume of spoil cannot be placed back within the mineral removal area due to stability constraints in the steep terrain and the swell of the rock due to blasting. The spoil that is placed within the boundary must be offset from the outcrop by approximately 60 feet to allow for a berm, ditch, and access road. Additionally, spoil can only be placed back on the mine area at an overall slope of 2.2:1 (Horizontal:Vertical). The excess spoil must be placed in a valley fill adjacent to the mine or on an older, nearby mine site if one is available. In the case of the surface area model mine, 251 million loose cubic

[15] Defining Perennial, Intermittent, and Ephemeral Channels in Eastern Kentucky: Application to Forestry Best Management Practices. By JR Svec, RK Kolka, and JW Stringer, 2005.

yards of excess spoil must be disposed. Typically, this spoil is placed in a valley fill, with the fill face sloped at an overall slope of 2.4:1 (H:V).

4.1.1.2. Surface Contour Mine

The contour operation, which, for modeling purposes, is located on the same property as the area mine, is also a multi-seam mine. The scale of operation is smaller than the area mine; therefore, the operation cannot economically mine the deeper seams that are accessible by the area mine. Therefore, the stripping ratio is reduced to 13.2:1. At an average production rate of 0.5 million tons per year, the smaller contour mine has a life of 10 years, not including development and reclamation time. The smaller contour model mine has similar requirements to the surface mine. The model mine has 5 million tons of coal resource with 83 million loose cubic yards of overburden. Most of the overburden is placed back on the mine bench to cover the highwall. After taking into account the offset for the berm, ditch and road, stability, and swell, the mine has 28 million loose cubic yards of excess spoil. This material is typically placed in an adjacent valley with similar requirement to those described under the surface area mine requirements.

4.1.2. Central Appalachian Underground Model Mine

The third Central Appalachian Region model mine, designed to model underground room and pillar coal operations, is a 0.25 million ton per year operation. The average coal seam thickness is 3.5 feet and the overburden ranges up to a maximum depth of approximately 550 feet. In room and pillar mining, coal must be left in place as pillars to support the roof; therefore, only 3 million tons of the 4.2 million ton resource can be mined. This is calculated assuming that 87% of the 3 million tons of mineable coal is mined using pillar recovery methods (high extraction: removing coal from pillars upon retreat) and that 13% of the 3 million tons of mineable coal is mined using conventional extraction for development (leaving coal in pillars for stability). This type of mining operation has an adit portal, where mining begins from the surface at the same elevation of the coal seam where the coal seam outcrops. The only material that will be placed as a fill in a stream is the face-up material that is removed to make room for the mine infrastructure on the surface. This small volume of material is temporarily placed in a valley until the mining operation is closed.

The following design parameters were followed with the room and pillar mine. The mine face-up area material is located in a neighboring valley during the mining phase. The target coal seam outcrops on the mine property; therefore, a 60 foot offset was included to prevent daylighting (the underground mine intersecting the ground surface) the operation. Additionally, mining does not occur under intermittent and perennial streams where there is less than 200 feet of cover to prevent material damage to the streams.

Underground mines are associated with a coal preparation plant. These plants may process coal from a number of smaller underground operations. In Central Appalachia, the plants are associated with slurry impoundments. The impacts of slurry impoundments due to the model mines were not covered in this Appendix. Refer to Appendix D for the slurry impoundment study.

4.2. Northern Appalachia

Northern Appalachia has two model mines. They represent both surface and underground production for the region. The model mine representing surface production is a small contour operation; while the underground model mine is a large, high productivity longwall operation. The digital terrain models used to generate the topographic contours for this region have a resolution of approximately three meters.

The streams were generated using a 7.8 acre drainage requirement for ephemeral streams on the contour mine and 1.4 acre drainage requirement for ephemeral streams over the longwall mine. These drainages were determined from representative permits. The Intermittent/Perennial streams were delineated using the NHD.

4.2.1. Northern Appalachian Surface Model Mine

The surface contour mine produces 0.2 million tons per annum over eight years. The mining ratio is similar to that of the Central Appalachian contour mine at 12.7:1; however, the topography is less steep. The shallower slopes allow the entire volume of mine spoil to be placed back onto the mineral removal area. In a lot of cases, Northern Appalachian mines are remining operations; however, this model assumes the land is virgin. For this type of mine, the majority of stream impacts are temporary and are associated with sedimentation pond construction, which was not a part of this study.

4.2.2. Northern Appalachian Underground Model Mine

The underground longwall operations in Northern Appalachia are extensive, long term mining complexes. The permits are usually extended periodically so that the operation covers multiple permits, but the model mine was designed to mirror a single permit. For the model, the permit area (mineral removal boundary in this case) covers nearly 7,000 acres. Only 67% of the coal within the mineral removal boundary is mined using longwall methods (assume 100% extraction). The remaining area is mined using room and pillar methods and consists of development areas and high extraction areas. As designed, this mine would operate for approximately ten years at a full production of 4.6 million tons per annum. The mine would most likely be expanded near the end of the permit life. The coal seam averages seven feet thick and lies 610 feet to 1,330 feet below the surface.

Longwall mines are typically associated with preparation plants. Over the life of the mine, each plant processes a high volume of coal and waste rock. The modeling for the refuse disposal from the plant associated with this model mine is described in Appendix D.

Design parameters that are covered by the model mine include barrier pillars between sets of longwall panels to prevent major subsidence, panel orientation for rock mechanics requirements, and panel dimensions, which are typical for the region.

4.3. Colorado Plateau

Two model mines are associated with the Colorado Plateau Region. The first operation, a surface strip mine, models typical surface mining operations in northwest New Mexico and northeast Arizona. The second model mine is an underground mine that is typical of longwall operations in the mountainous terrain of Utah and Colorado.

For both mines, ephemeral streams were generated using a seven acre drainage area. In the Colorado Plateau region, hydrologically intermittent streams can be identified by the vegetation that grows along the stream banks. Therefore, the intermittent stream points were chosen based on the vegetation that was identified using Google Earth[16] and Virtual Earth[17] aerial images.

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[16] Google Earth (Version 7.1.1.1888) [Software]. Mountain View, CA: Google Inc.

4.3.1. Colorado Plateau Surface Model Mine

The model surface mine covers 3,311 acres with 92.2 million tons of coal and is designed to produce 4.1 million tons per annum at a 9.8:1 stripping ratio. Based on the representative permits, the model includes up to five mineable seams at a depth up to 200 feet. The total thickness of all coal seams averages approximately 16 feet thick. The model mine has 916 million bank cubic yards of spoil material, which can all be placed back within the mining area.

4.3.2. Colorado Plateau Underground Model Mine

The second model mine uses longwall methods to mine 3.7 million tons per year from 27.0 million tons of coal resource over 2,188 acres. The coal seam ranges from six to nine feet in thickness with a depth of cover between 110 and 1,670 feet due to the topographic relief. The mine is a combination of longwall and room and pillar methods. The longwall method applies to uniform areas that allow high extraction, while the room and pillar method applies where stability is a concern in low-cover areas. The model design is similar to that of other longwall model mines in that it assumes the mine is a single permit from a multi-permit mining complex. The mine was designed with longwall panel geometry typical of the region. The panels were not placed under areas of minimum cover. Additionally, mines in this region can be multi-level operations; however, this model assumes the mine is a single level operation. The preparation plant refuse disposal area impact analysis is described in Appendix D.

4.4. Gulf Coast

The gulf coast region primarily consists of surface lignite operations; therefore, the model mine is designed to represent the unique aspects of those operations. The mineral removal boundary covers 1,988 acres with 40.7 million tons of coal at a mining ratio of 10.3 bank cubic yards of overburden per ton of coal. The model has a 12 year mine life producing coal at an average rate of 3.3 million tons per year. The coal lies in four seams with a total thickness averaging approximately 12.5 feet thick. Interburden thicknesses range from 17 to 70 feet, and the lowest coal seam lies up to 190 feet below the surface. The volume of spoil associated with the Gulf Coast model mine is 420 million bank cubic yards. This material would be placed completely within the mineral removal area.

The ephemeral stream reaches in the Gulf Coast Region were generated using an ephemeral drainage requirement of approximately 2 acres. This drainage area was determined using the representative permits from the region. The mine does not have hydrologically intermittent streams on-site. However, some streams do have a drainage area of one square mile or greater. Therefore, due to the requirements of some alternatives, those sections of the ephemeral streams may be classified as intermittent streams.

4.5. Illinois Basin

The model mines in the Illinois Basin represent one method of surface mining and two methods of underground mining. The surface mine uses the area mining method, while the larger underground mine is primarily a longwall operation and the smaller underground mine is a room and pillar operation. The digital terrain model for this area has a resolution of approximately ten meters.

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[17] Images from MicrosoftVirtual Earth Hybrid Image Server.

Due to the agriculture industry, many streams in the Illinois Basin are man-made drainage ways for removal of surface water drainage. Since these are not easily modeled with the GIS software, the streams in the Illinois Basin were only generated using ephemeral drainage area requirements. The 7.4 acre drainage that was used for the region was calculated using the representative permits for both the underground and the surface mines. The surface mine has two hydrologically defined intermittent streams running through the middle of the mineral removal area. These were identified using aerial images. The intermittent and perennial streams were delineated using the NHD dataset. Stream impacts for the underground mines are only quantified for the coal refuse impoundment.

4.5.1. Illinois Basin Surface Model Mine

The Illinois Basin surface mine production is one million tons of coal per year with a 12 year mine life. The mining ratio averages 15.5:1 over 1067 acres. The coal, which has a cumulative average thickness of between six to seven feet, is broken into three individual seams that lie up to 120 feet below the surface.

In the Illinois Basin, surface mines place the initial open-cut spoil in a mound next to the initial cut. The material generated by the second cut will be used to fill in the first cut. The final cut pit will frequently be left open to fill with water as a final pit impoundment depending on the approved reclamation plan and post-mining land use. With the requirement to reclaim 100 percent of all mined prime farmland acres, the size of final pit impoundments may be reduced. These permanent impoundments frequently serve as valuable fish and wildlife habitat as well and as potentially valuable resource to the agriculture industry and other water users. This open-cut spoil placement practice has been duplicated in the model surface mine for the Illinois Basin Region.

4.5.2. Illinois Basin Underground Model Mines

Two model mines were generated for the Illinois Basin to represent two significant underground mining methods that are used in the region: longwall and room and pillar.

4.5.2.1. Illinois Basin Longwall Mine

The longwall mine is designed to model the larger producing underground mines in the Illinois Basin. Using the same logic as the models for the other longwall mines, this model mine was limited to a permit boundary covering 11,265 acres. The model longwall mine is designed to produce six million tons of coal per year from a coal seam ranging from 5.5 to 7.5 feet thick at a depth of cover of 380 to 600 feet.

4.5.2.2. Illinois Basin Room and Pillar Mine

The smaller underground operations in the Illinois Basin are modeled by the room and pillar model mine. This mine is designed to cover 4,146 acres and operate at a production rate 2.1 million tons per year over approximately nine years, not including development and reclamation time. The mine operates in using the same model topography and coal seam information as the longwall mine; therefore, the coal ranges between 5.5 and 7.5 feet thick. The coal seam elevation has been adjusted from the longwall mine to associate the seam with 200 to 300 feet of overburden. The shallower overburden requires the room and pillar method for subsidence control.

The two types of underground mines will typically have a processing plant on site or be associated with a nearby plant. The modeling for the refuse disposal from the plants is described in Appendix D.

4.6. Northern Rocky Mountains and Great Plains

The Northern Rocky Mountains and Great Plains surface model mine encompasses a mineral removal area of over 6,000 acres in the Powder River Basin in Wyoming. The operation is designed to produce 27.2 million tons of coal per annum at a mining ratio of 1.5 bank cubic yards of overburden per ton of coal. With 1,061 million tons of mineable coal, the operation is projected to produce coal for approximately 39 years, disregarding development and shutdown time and assuming there will not be an expansion of the mining area. Unique to western mining operations such as this, the postmining topography will be lower in elevation than original topography due to the thin overburden thickness relative to the coal seam thickness.

The streams in the Northern Rocky Mountains and Great Plains Region were delineated using an ephemeral drainage requirement of 13.6 acres based on the representative permits. The intermittent streams were delineated using either a one square mile drainage requirement or aerial images, depending on the requirements of the alternative.

4.7. Northwest

The Northwest Region coal production is represented by a model mine located in Alaska. The volume calculations and contours are based on a digital elevation model with a resolution of approximately 10 meters. This mine is unique in that it is affected by permafrost. Due to the poor stability, the mine has cutbacks above the mined area to lay the spoil slopes back to 4:1 (H:V). The model mine is designed to produce two million tons per year over 15 to 20 years at a mining ratio of 3.8:1. The sum of the average thickness of each of the three coal seams mined in the model mine is 66 feet. The average overburden thickness is 290 feet.

The operating mine currently has an excess spoil disposal area, which is partially used as a dump site for waste from a nearby power plant. The fill was permitted due to a lack of surface area within the mine site to place spoil; however, from discussions with the regulatory agency, this scenario is unique to this permit. Any future permits will not generate excess spoil; therefore, excess spoil fills were not included in the alternative analysis.

The streams for the Northwest Region model mine were delineated using an ephemeral drainage requirement of 8.4 acres. The intermittent points for the streams were identified with similar logic to the Central Appalachian model mine scenarios, using coal seams as markers for the groundwater component of intermittent streams. The highest coal seam mined was used for this purpose.

5. COST SECTION

After assessing the metrics for each model mine and alternatives, MWC estimates cost impacts applicable to operational changes that are potentially impacted by the Stream Protection Rule. Costs that were not impacted (such as drilling and blasting) were not reviewed as they were outside the scope of this analysis. The following costs were assessed (as applicable) for each Model mine:

- Haulage
- Landforming
- Required Restoration of Stream Form and Function

- Stream Enhancement or Changes in Compensatory Mitigation Requirements
- Reforestation and Postmining Land Use Changes
- Enhanced Permitting

5.1. Haulage Costs

The Haulage costs are only applicable to Model mines that may require excess valley fills. These are the Surface Model mines in the Central Appalachian Region and the Northwest Region. The Haulage costs in all of the other Surface Model mines would not change from the No Action Alternative (Alternative 1). Haulage costs for this document can be defined as "Total Life of Mine costs for the haulage of overburden by truck and/or movement of overburden by bulldozer".

Haulage costs vary depending on the number of valley fills; whether the fill material could be dumped off the edge of the permit into the adjacent valley or hauled to the toe of the fill; and where the fill(s) are located in relation to the mining activity. Due to the nature of these factors and the day-to-day changes in haulage patterns for a mining operation, general assumptions were necessary (see below). In addition, the Haulage cost is limited to the cost of spoil material handling and does not include the haulage cost to extract coal.

Shown below are the variables that are considered in the calculation of the Haulage costs;

1. Life of Mine Overburden Volume – Estimate of total overburden volume to be mined to extract the coal resource. A geologic model was constructed to calculate these volumes.

2. Percentage of Truck Haulage vs. Bulldozer Movement - The analysis assumes that bulldozers excavate the first lift on the mineral extraction area and that trucks would be responsible for transporting the remaining spoil.

    - The Central Appalachian Area Model mine uses a combination of 90% 224 cubic yard trucks and 10% 102 cubic yard trucks to haul 80% of the overburden.
    - The Central Appalachian Contour Model mine uses 100% 102 cubic yard trucks to move 70% of the overburden.
    - The Northwest Area Model mine uses 100% 102 cubic yard trucks to move 78% of the overburden.

    These numbers are used to calculate the required number of trips for each type of equipment, assuming the material will not be handled multiple times.

3. Trips per hour is the driving factor for the change in Haulage costs between alternatives (Table 16). This factor is calculated using conceptual haulage routes and distances for each of the Alternatives. See Table 16 for average trip data.
    - The weighted average haul distance of all trips was estimated using the weighted average distance of on-bench spoil placement and weighted average distance to fill area.
    - For Central Appalachia surface area mines and Northwest surface mines, the average haul distance used was 7,000 feet. For Central Appalachia surface contour mines, the average haul distance used was 7,500 feet.

- These numbers were adjusted for flat haul, haul on slopes of 15% grade uphill and downhill, and percent of material hauled to each location.
- The distances traveled on level ground, uphill, and downhill were used to calculate an approximate *cycle time* for an average haul. The cycle time included position time, fill time, haul time, dump position and dump time, and return time.
- Average speeds for each type of haul were taken from the Caterpillar Performance Handbook[18]. The number of trips per hour factor includes job efficiency, loader availability, and truck availability.
- The total number of hours required for the trucks and dozers is equal to dividing the total number of trips required to move the overburden by the average haul rate in trips per hour.

Alternative	Central Appalachia Area Mine (trips/hr)	Central Appalachia Contour Mine (trips/hr)
Alternative 1	3.37	3.79
Alternative 2	2.94	2.94
Alternative 3	3.37	3.62
Alternative 4	3.37	3.62
Alternative 5	3.37	3.62
Alternative 6	3.37	3.62
Alternative 7	3.37	3.62
Alternative 8	3.37	3.62
Alternative 9	3.37	3.79

Table 16: Average haulage rate (trips/hr)

Note: The bulldozer factor was constant throughout the analysis at 17.36 trips per hour.

4. Cost per hour for Haulage Trucks and Bulldozers were obtained from the Caterpillar Performance Handbook[19] and other estimated data including ownership cost as a function of truck purchase price and life; fuel cost and consumption rate; tire cost; operator cost; and maintenance cost. The following rates apply:

   - 224 Cubic Yard Capacity Haulage Trucks	$617 per hour
   - 102 Cubic Yard Capacity Haulage Trucks	$353 per hour
   - 24 Cubic Yard Capacity Bulldozers	$244 per hour

5. Haulage costs were calculated as follows:

   (Total Haulage Truck Hours x Haulage Truck cost per hour) + (Total Bulldozer Hours x Bulldozer cost per hour) = Haulage cost

5.1.1. Alternative 1 Haulage Costs

Initial Haulage costs were calculated for the No Action Alternative (Alternative 1) to provide a baseline for comparison of all of the remaining Alternatives (Table 17). Current mining regulations permit construction of hollow fills in lifts up to 100 feet in elevation. These lifts are placed by haulage trucks

[18] Caterpillar, Inc. "Caterpillar Performance Handbook, ed. 39," (2009)
[19] Caterpillar, Inc. "Caterpillar Performance Handbook, ed. 39," (2009)

that traverse the valley on roads constructed on 10 to 15% grades. Consistent with current practice, durable rock fill construction is not assumed to be used by coal companies applying for a SMCRA permit under Alternative 1. The BMP's required by the SMCRA application and the Alternative analysis required in the 404B permit make approval of an application with a durable rock fill very difficult.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	**Total Cost**
	Unit Cost		Total Hours				
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)			
Central Appalachia - Area	$244	$591	348,189	830,094	$84,968,625	$490,594,040	**$575,562,665**
Central Appalachia - Contour	$244	$353	60,039	150,622	$14,651,329	$53,204,338	**$67,855,667**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**

Table 17: Alternative 1 Haulage Costs

Note: On all ensuing cost tables the columns "ICC (Incremental Cost Change) from Alternative 1" and "Percent ICC from Alternative 1" will/could be present. These columns will portray the change in costs between the No Action Alternative and each respective Action Alternative.

5.1.2. Alternative 2 Haulage Costs

Haulage costs for Alternative 2 (Table 18) will be described separately for the Central Appalachian region and the Northwest Region.

5.1.2.1. Central Appalachian Region

Under Alternative 2, hollow fills cannot be constructed because of the prohibition of spoil being placed into perennial and intermittent streams. In this alternative the excess spoil is hauled to an off-site dump site. This cost calculation assumed the site is 10,000 feet (less than two miles) away from the mine site. Therefore, this alternative has the highest Haulage cost for spoil placement in the Central Appalachian region.

5.1.2.2. Northwest Region

The Alternative 2 Haulage costs for the Northwest Region mirror the costs from the Baseline because there are no excess spoil fills.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	**Total Cost**	**ICC from Alternative 1**	**Percent ICC from Alternative 1**
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	949,940	$84,968,625	$561,424,088	**$646,392,713**	**$70,830,048**	**12%**
Central Appalachia - Contour	$244	$353	60,039	193,824	$14,651,329	$68,464,464	**$83,115,793**	**$15,260,125**	**22%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 18: Alternative 2 Haulage Costs

5.1.3. Alternative 3 Haulage Costs

Haulage Costs in Alternative 3 have been altered (from the Baseline) by the prohibition of durable rock fills and the requirement of "bottom- up" construction which requires that excess spoil be placed in the hollow fills in approximately 4 foot lifts. The bottom-up construction requirement has instituted an additional bulldozer cost (as shown in Table 19). Unique to Alternative 3 in comparison to Alternatives 4 thru 8 is that Flat Deck fill designs are allowed.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$91,302,536	$490,594,040	**$581,896,576**	**$6,333,911**	**1%**
Central Appalachia - Contour	$244	$353	60,039	150,622	$14,651,329	$56,904,824	**$71,556,153**	**$3,700,486**	**5%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 19: Alternative 3 Haulage Costs

5.1.4. Alternative 4 Haulage Costs

As shown in Table 20, Haulage Costs in Alternative 4 have been altered (from the Baseline) by the prohibition of durable rock fills and the requirement of "bottom- up" construction which requires that excess spoil be placed in the hollow fills in approximately 4 foot lifts. The bottom-up construction requirement has instituted an additional bulldozer cost. Flat Deck fills are prohibited in Alternative 4.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$91,302,536	$490,594,040	**$581,896,576**	**$6,333,911**	**1%**
Central Appalachia - Contour	$244	$353	60,039	157,683	$16,279,542	$55,698,227	**$71,977,769**	**$4,122,102**	**6%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 20: Alternative 4 Haulage Costs

5.1.5. Alternative 5 Haulage Costs

Alternative 5 Haulage costs (Table 21) are identical to Alternative 4 (see explanation above) since the requirements allow for valley fills to be constructed, but do not allow flat decks on valley fills.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$91,302,536	$490,594,040	**$581,896,576**	**$6,333,911**	**1%**
Central Appalachia - Contour	$244	$353	60,039	157,683	$16,279,542	$55,698,227	**$71,977,769**	**$4,122,102**	**6%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 21: Alternative 5 Haulage Costs

5.1.6. Alternative 6 Haulage Costs

Alternative 6 Haulage costs (Table 22) are identical to Alternative 4 (see explanation above) since the requirements allow for valley fills to be constructed, but do not allow flat decks on valley fills.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	**Total Cost**	**ICC from Alternative 1**	**Percent ICC from Alternative 1**
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$91,302,536	$490,594,040	**$581,896,576**	**$6,333,911**	**1%**
Central Appalachia - Contour	$244	$353	60,039	157,683	$16,279,542	$55,698,227	**$71,977,769**	**$4,122,102**	**6%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 22: Alternative 6 Haulage Costs

5.1.7. Alternative 7 Haulage Costs

Alternative 7 Haulage costs (Table 23) are identical to Alternative 4 (see explanation above) since the requirements allow for valley fills to be constructed, but do not allow flat decks on valley fills.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	**Total Cost**	**ICC from Alternative 1**	**Percent ICC from Alternative 1**
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$91,302,536	$490,594,040	**$581,896,576**	**$6,333,911**	**1%**
Central Appalachia - Contour	$244	$353	60,039	157,683	$16,279,542	$55,698,227	**$71,977,769**	**$4,122,102**	**6%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 23: Alternative 7 Haulage Costs

5.1.8. Alternative 8 Haulage Costs

Alternative 8 Haulage costs (Table 24) are identical to Alternative 4 (see explanation above) since the requirements allow for valley fills to be constructed, but do not allow flat decks on valley fills.

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	**Total Cost**	**ICC from Alternative 1**	**Percent ICC from Alternative 1**
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$91,302,536	$490,594,040	**$581,896,576**	**$6,333,911**	**1%**
Central Appalachia - Contour	$244	$353	60,039	157,683	$16,279,542	$55,698,227	**$71,977,769**	**$4,122,102**	**6%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 24: Alternative 8 Haulage Costs

5.1.9. Alternative 9 Haulage Costs

Alternative 9 Haulage costs (Table 25) are identical to the Baseline (Alternative 1).

Region - Model Mine	Factors				Dozer Cost	Haul Truck Cost	**Total Cost**	**ICC from Alternative 1**	**Percent ICC from Alternative 1**
	Unit Cost		Total Hours						
	Dozer ($/hr)	Haul Truck ($/hr)	Dozer (hrs)	Haul Truck (hrs)					
Central Appalachia - Area	$244	$591	348,189	830,094	$84,968,625	$490,594,040	**$575,562,665**	**$0**	**0%**
Central Appalachia - Contour	$244	$353	60,039	150,622	$14,651,329	$53,204,338	**$67,855,667**	**$0**	**0%**
Northwest - Area	$244	$353	90,654	328,182	$22,122,288	$115,923,589	**$138,045,877**	**$0**	**0%**

Table 25: Alternative 9 Haulage Costs

5.1.10. Summary of Haulage Costs

The Haulage Costs for the Baseline and Action Alternatives are summarized below:

- The Baseline (Alternative 1) and Alternative 9 have identical Haulage Costs. This is due to the Baseline conditions being very similar to the 2008 EIS guidelines.
- Alternative 2 has the largest Haulage costs due to the prohibition of placement of spoil in perennial or intermittent streams.
- Alternatives 3 thru 8 have Haulage costs higher than the Baseline due to the prohibition of durable rock fills and the change to bottom-up fill construction which requires additional bulldozer cost.

5.2. Landforming Costs

The landforming costs measure the additional cost an operator incurs to regrade the post-mining landscape in a way that more closely resembles natural and stable hill slopes and landforms. For modeling purposes, landforming is separated into two categories: final grading and engineering. No Landforming costs were calculated for the Underground Model mines.

Final Grading Costs are defined as follows:

- Final grading of the backfilled and excess spoil disposal areas will be accomplished with a bulldozer. Utilizing the CAT Handbook and best professional judgment an operating cost of $140 per hour was assigned for a D8 size bulldozer. An 8 hour shift will be required to accomplish the final grading on 1 acre of disturbed area.
- Final Grading costs will be calculated by multiplying the Total Disturbed Area (in acres) of the respective Model mine by $1,120 per acre.

Engineering Costs are defined as follows:

- Engineering includes photogrammetry, contour mapping, digital terrain modeling and engineering necessary to confirm that the volumes and the regraded spoil configuration adhere to the AOC guidelines. Investigation into similar projects and professional judgment imply a fee of $50 per acre of disturbed area for the Engineering costs.
- Engineering costs will be calculated by multiplying the total disturbed area (in acres) of the respective Model mine by $50 per acre.

Note: disturbed areas that are classified as Stream Restoration area in the western Coal Regions are subtracted from the Total disturbed area for calculation of Landforming costs.

5.2.1. Alternative 1 Landforming Costs

The No Action Alternative (Alternative 1) does not require landforming; therefore, no costs are incurred. Note that the "Total cost" and the "ICC (Incremental Cost Change) from Alternative 1" is the same column because all Landforming costs for the No Action Alternative (Alternative 1) are $0, therefore the Total costs and ICC from Alternative 1 are equal.

5.2.2. Alternative 2 Landforming Costs

Landforming costs are required for Alternative 2 (Table 26). Note that Stream Restoration areas that are subtracted from the Disturbed area in the Western Regions are calculated with streams lengths for perennial, intermittent and 90% of the ephemeral streams.

Region - Model Mine	Factors				Final Grading Cost	Engineering Cost	**Total Cost - ICC from Alternative 1**
	Bulldozer Work ($/acre)	Digital Terrain Modeling ($/acre)	Disturbed Area (acres)	Stream Restoration Area (acres)			
Central Appalachia - Area	$1,120	$50	1,116	0	$1,250,032	$55,805	**$1,305,837**
Central Appalachia - Contour	$1,120	$50	371	0	$415,520	$18,550	**$434,070**
Northern Appalachia - Contour	$1,120	$50	205	0	$229,264	$10,235	**$239,499**
Colorado Plateau - Area	$1,120	$50	3,311	406	$3,254,457	$165,570	**$3,420,027**
Gulf Coast - Area	$1,120	$50	1,988	142	$2,067,532	$99,420	**$2,166,952**
Illinois Basin - Area	$1,120	$50	1,067	0	$1,195,152	$53,355	**$1,248,507**
Northern Rocky Mountains and Great Plains - Area	$1,120	$50	6,049	460	$6,260,423	$302,460	**$6,562,883**
Northwest - Area	$1,120	$50	497	0	$556,416	$24,840	**$581,256**

<u>Table 26: Alternative 2 Landforming Costs</u>

5.2.3. Alternative 3 Landforming Costs

Landforming costs are required for Alternative 3 (Table 27). Note that Stream Restoration areas that are subtracted from the Disturbed area in the western Coal Regions are calculated with streams lengths for perennial, intermittent and 50% of the ephemeral streams.

Region - Model Mine	Factors				Final Grading Cost	Engineering Cost	**Total Cost - ICC from Alternative 1**
	Bulldozer Work ($/acre)	Digital Terrain Modeling ($/acre)	Mineral Removal Area (acres)	Stream Restoration Area (acres)			
Central Appalachia - Area	$1,120	$50	1,116	0	$1,250,032	$55,805	**$1,305,837**
Central Appalachia - Contour	$1,120	$50	371	0	$415,520	$18,550	**$434,070**
Northern Appalachia - Contour	$1,120	$50	205	0	$229,264	$10,235	**$239,499**
Colorado Plateau - Area	$1,120	$50	3,311	260	$3,417,262	$165,570	**$3,582,832**
Gulf Coast - Area	$1,120	$50	1,988	92	$2,123,999	$99,420	**$2,223,419**
Illinois Basin - Area	$1,120	$50	1,067	0	$1,195,152	$53,355	**$1,248,507**
Northern Rocky Mountains and Great Plains - Area	$1,120	$50	6,049	298	$6,441,642	$302,460	**$6,744,102**
Northwest - Area	$1,120	$50	497	0	$556,640	$24,850	**$581,490**

<u>Table 27: Alternative 3 Landforming Costs</u>

5.2.4. Alternative 4 Landforming Costs

Landforming costs for alternative 4 are shown in Table 28. The disturbed area for Central Appalachia has changed due to the Landforming being required for all hollow fill areas. Note that Stream Restoration areas that are subtracted from the Disturbed area in the western Coal Regions are calculated with streams lengths for perennial, intermittent and 50% of the ephemeral streams (One square mile watershed intermittent streams are considered ephemeral streams for this Alternative).

Region - Model Mine	Factors				Final Grading Cost	Engineering Cost	**Total Cost - ICC from Alternative 1**
	Bulldozer Work ($/acre)	Digital Terrain Modeling ($/acre)	Disturbed Area (acres)	Stream Restoration Area (acres)			
Central Appalachia - Area	$1,120	$50	1,260	0	$1,410,976	$62,990	**$1,473,966**
Central Appalachia - Contour	$1,120	$50	448	0	$501,760	$22,400	**$524,160**
Northern Appalachia - Contour	$1,120	$50	205	0	$229,264	$10,235	**$239,499**
Colorado Plateau - Area	$1,120	$50	3,311	237	$3,443,111	$165,570	**$3,608,681**
Gulf Coast - Area	$1,120	$50	1,988	92	$2,123,999	$99,420	**$2,223,419**
Illinois Basin - Area	$1,120	$50	1,067	0	$1,195,152	$53,355	**$1,248,507**
Northern Rocky Mountains and Great Plains - Area	$1,120	$50	6,049	268	$6,475,341	$302,460	**$6,777,801**
Northwest - Area	$1,120	$50	497	0	$556,416	$24,840	**$581,256**

Table 28: Alternative 4 Landforming Costs

5.2.5. Alternative 5 Landforming Costs

In Alternative 5 only areas with steep slopes/excess spoil structures (Central and Northern Appalachia) have Landforming costs (Table 29).

Region - Model Mine	Factors			Final Grading Cost	Engineering Cost	**Total Cost - ICC from Alternative 1**
	Bulldozer Work ($/acre)	Digital Terrain Modeling ($/acre)	Disturbed Area (acres)			
Central Appalachia - Area	$1,120	$50	1,260	$1,410,976	$62,990	**$1,473,966**
Central Appalachia - Contour	$1,120	$50	448	$501,760	$22,400	**$524,160**
Northern Appalachia - Contour	$1,120	$50	205	$229,264	$10,235	**$239,499**

Table 29: Alternative 5 Landforming Costs

5.2.6. Alternative 6 Landforming Costs

Alternative 6 does not have any requirements for Landforming.

5.2.7. Alternative 7 Landforming Costs

In Alternative 7 only areas with steep slopes/excess spoil structures have Landforming costs (Table 30).

Region - Model Mine	Factors			Final Grading Cost	Engineering Cost	**Total Cost - ICC from Alternative 1**
	Bulldozer Work ($/acre)	Digital Terrain Modeling ($/acre)	Disturbed Area (acres)			
Central Appalachia - Area	$1,120	$50	1,260	$1,410,976	$62,990	**$1,473,966**
Central Appalachia - Contour	$1,120	$50	448	$501,760	$22,400	**$524,160**
Northern Appalachia - Contour	$1,120	$50	205	$229,264	$10,235	**$239,499**

Table 30: Alternative 7 Landforming Costs

5.2.8. Alternative 8 Landforming Costs

Landforming costs for Alternative 8 mirror Alternative 1; therefore, no costs are incurred.

5.2.9. Alternative 9 Landforming Costs

The Alternative 9 does not require landforming; therefore, no costs are incurred.

5.2.10. Summary Landforming Costs

The Landforming Costs for the Baseline and Action Alternatives are summarized below:

- Landforming is not required in Alternatives 1, 6, 8 and 9
- The change in Landforming costs due to the exclusion of the Stream Restoration acreage was minimal (3 to 5%)
- Landforming costs for the Appalachian Model Mines was the same for all Action Alternatives requiring landforming.
- For the larger surface Model Mines (Colorado Plateau and Northern Rocky Mountains and Great Plains) the Landforming Costs were significant in comparison to overall costs for each alternative.

5.3. Required Restoration of Stream Form and Function

The Stream Restoration cost is associated with the requirement to restore the form and biological function of mined through intermittent and perennial streams and the form of mined through ephemeral streams. This requirement applies in some manner to surface mines in all regions. Stream Restoration will include but not be limited to the following operations: establish drainage, creation of base channel (sinuosity, appropriate gradient, bank construction), construction of flow inhibitors (instream structures), construction of substrate, and revegetation of impacted surrounding riparian areas.

As outlined in Section 4.2 of this Appendix, the generation of stream location and classification is based on the representative permits and varies regionally. A compilation of the assumptions used for stream generation and the ensuing stream impacts is shown in Table 31.

Coal Producing Region	Watershed Area for Initiation of Ephemeral Stream	Criteria for Initiation of Intermittent Stream
Appalachia	14.5 acres	Watershed area of 19.8 acres or lowest coal outcrop (down dip streams)
Colorado Plateau	7 acres	In Alternatives 1,3,5,6 and 9 the Intermittent stream is initiated at a 1 square mile watershed area. In Alternatives 2, 4,7 and 8 the initiation of the Intermittent stream is hydrologically and observation based.
Gulf Coast	21.8 acres	In Alternatives 1,3,5,6 and 9 the Intermittent stream is initiated at a 1 square mile watershed area. In Alternatives 2, 4,7 and 8 the initiation of the Intermittent stream is hydrologically and observation based.
Illinois Basin	7.4 acres	In Alternatives 1,3,5,6 and 9 the Intermittent stream is initiated at a 1 square mile watershed area. In Alternatives 2, 4,7 and 8 the initiation of the Intermittent stream is hydrologically and observation based.
Northern Rocky Mountains	13.6 acres	In Alternatives 1,3,5,6 and 9 the Intermittent stream is initiated at a 1 square mile watershed area. In Alternatives 2, 4,7 and 8 the initiation of the Intermittent stream is hydrologically and observation based.
Northwest	8.4 acres	In Alternatives 1,3,5,6 and 9 the Intermittent stream is initiated at a 1 square mile watershed area. In Alternatives 2, 4,7 and 8 the initiation of the Intermittent stream is hydrologically and observation based.

Table 31: Watershed Acreage for Stream Delineation

5.3.1. Cost Factors

Cost factors are applied to the mined thru stream lengths. The cost factors are either the cost per unit foot of stream impact or cost per unit acre of stream corridor impact. These factors are based on the following sources:

1. Cost per foot for stream restoration (Table 32):
    a. The Huntington USACE Corps District reported to Environmental Law Institute report (ELI) an in-lieu fee of $100 per linear foot; however, since the time of that report, fees have escalated to a recommended $400 per linear foot, and most recently $800 per linear foot[20]. Due to the steep slope topography in Central Appalachia, in combination with the requirement under all alternatives to restore mined through streams, the Stream Restoration cost for Central Appalachia was set at $600 per linear foot for intermittent/perennial streams and $400 per foot for ephemeral streams. The ephemeral stream cost was also extrapolated to the Northern Appalachian Region.
    b. The Stream Restoration costs for the Northwest region were derived from a 2007 ELI[21], which surveyed the U.S. Army Corps of Engineers districts regarding the costs of stream restoration under the Clean Water Act section 404 Compensatory Mitigation Program. The Alaska district reported a cost of $235 per linear foot. This was the only information found relating to Stream Restoration costs in Alaska and was thus used for this analysis.

[20] *See* the West Virginia Stream and Wetland Valuation Metric 2.0, which uses $800 as the default value for in lieu fee mitigation.

[21] Environmental Law Institute, "Mitigation of Impacts to Fish and Wildlife Habitat: Estimating Costs and Identifying Opportunities." Washington, D.C. 2007, *available at*: http://www.elistore.org/reports_detail.asp?ID=11248.

c. In addition, since no information was available for Stream Restoration costs in the western regions or the Illinois Basin, these costs were estimated using the 2008 USACE data and best professional judgment. The stream restoration per foot cost was set at $300.

Cost for Restoration of Stream Form and Function			
Region	Intermittent and Perennial ($/ft)	Ephemeral Streams ($/ft)	Ephermal Corridor ($/acre)
Central Appalachia	$600	$400	-
Northern Appalachia	-	$400	-
Colorado Plateau	$300	-	$10,000
Gulf Coast	$300	-	$10,000
Illinois Basin	$300	$300	-
Northern Rocky Mountains and Great Plains	$300	-	$10,000
Northwest	$235	$235	-

Table 32: Stream Restoration Costs

2. In some regions, there can be upwards of 10 or more miles of mined thru ephemeral streams and that the majority of the restored ephemeral streams are constructed through the final regrading of the mine spoil. In this case, the impacted stream corridor has a cost factor applied to account for the area of grading. This cost factor is based on professional judgment.

5.3.2. Costing Methods

- The first method is based on the stream impact metric, which is an estimate of the total length of ephemeral, intermittent, and perennial streams that are mined through in each Alternative/Model mine scenario. Each foot of stream impact is multiplied by a restoration cost per foot factor (Table 32).
- In the Colorado Plateau, Gulf Coast and Northern Rocky Mountains and Great Plains coal producing regions, the ephemeral Stream Restoration cost is calculated by multiplying a 100 foot wide corridor by the length of stream impacted to realize an “area” of stream influence. This area of stream influence (in acres) is then multiplied by a unit grading factor to find the restoration cost of the mined thru ephemeral streams (Table 32).
- Restoration rates of ephemeral streams was subjected to Alternative specific factors of the following:
    - In Alternatives 2 and 7, 90% of the mined thru ephemeral streams are required to be restored.
    - In Alternatives 3, 4, 5, 6 and 8 50% of the mined thru ephemeral streams are required to be restored.

5.3.3. Alternative 1 Stream Restoration Costs

Stream Restoration costs were applied to all of the Surface Model mines except for the Northern Appalachian mine since the model only impacted ephemeral streams (Ephemeral streams are not restored in Alternative 1. Streams with greater than one sq. mile drainage, although ephemeral in nature, are treated as intermittent in Alternative 1). The I/P streams are designed and constructed as to restore the approximate the pre-mining characteristics of the original stream channel, these operations are included in the costs for Alternative 1. The Stream Restoration costs in Table 33 were calculated under Alternative 1. For hydrologically defined intermittent streams, a “cost per foot” factor is applied; however, for intermittent streams defined by a drainage area of one square mile or greater (with ephemeral drainage characteristics), a “cost per acre” factor is applied. The acreage is calculated by applying an ephemeral corridor width to the stream.

Region - Model Mine	Factors					Total Cost
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	
Central Appalachia - Area	$600	$0	0	1,444	0	**$866,400**
Central Appalachia - Contour	$600	$0	0	302	0	**$181,200**
Northern Appalachia - Contour						**N/A**
Colorado Plateau - Area	$300	$10,000	100	11,605	20,107	**$3,943,093**
Gulf Coast - Area	$300	$0	0	12,611	0	**$3,783,300**
Illinois Basin - Area	$300	$0	0	15,140	0	**$4,542,000**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100	12,102	26,213	**$4,232,368**
Northwest - Area	$235	$0	0	7,903	0	**$1,857,205**

Table 33: Alternative 1 Stream Restoration Costs

5.3.4. Alternative 2 Stream Restoration Costs

The costs for stream restoration in Alternative 2 (Table 34) include restoring all ephemeral streams to form only.

Region	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600			$400	90%	1,444	0	2,156	**$1,642,560**	**$776,160**	**90%**
Central Appalachia - Contour	$600			$400	90%	302	0	235	**$265,800**	**$84,600**	**47%**
Northern Appalachia - Contour				$400	90%	0	0	423	**$152,280**	**$152,280**	
Colorado Plateau - Area	$300	$10,000	100		90%	11,605	20,107	163,326	**$7,271,438**	**$3,328,345**	**84%**
Gulf Coast - Area	$300	$10,000	100		90%	12,611	0	54,904	**$4,917,680**	**$1,134,380**	**30%**
Illinois Basin - Area	$300			$300	90%	15,140	0	48,809	**$17,720,430**	**$13,178,430**	**290%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100		90%	12,102	26,213	182,756	**$7,948,141**	**$3,715,774**	**88%**
Northwest - Area	$235			$235	90%	7,903	0	7,141	**$3,367,527**	**$1,510,322**	**81%**

Table 34: Alternative 2 Stream Restoration Costs

5.3.5. Alternative 3 Stream Restoration Costs

The costs for stream restoration under Alternative 3 (Table 35) use the same formulae and factors as Alternative 2 except that an Alternative specific factor of 50% is applied to all ephemeral streams that are restored.

Region - Model Mine	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600		100	$400	50%	1,444	0	2,156	**$1,297,600**	**$431,200**	**50%**
Central Appalachia - Contour	$600		100	$400	50%	302	0	235	**$228,200**	**$47,000**	**26%**
Northern Appalachia - Contour	$0		100	$400	50%	0	0	423	**$84,600**	**$84,600**	
Colorado Plateau - Area	$300	$10,000	100		50%	11,605	20,107	163,326	**$5,817,818**	**$1,874,725**	**48%**
Gulf Coast - Area	$300	$10,000	100		50%	12,611	0	54,904	**$4,413,511**	**$630,211**	**17%**
Illinois Basin - Area	$300		100	$300	50%	15,140	0	48,809	**$11,863,350**	**$7,321,350**	**161%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100		50%	12,102	26,213	182,756	**$6,330,118**	**$2,097,750**	**50%**
Northwest - Area	$235			$235	50%	7,903	0	7,141	**$2,696,273**	**$839,068**	**45%**

Table 35: Alternative 3 Stream Restoration Costs

5.3.6. Alternative 4 Stream Restoration Costs

The Stream Restoration costs for Alternative 4 (Table 36) are approximately equal to those under Alternative 3 except for the removal of the one square mile watershed definition for intermittent streams. As shown in Table 36 below the stream footage shown in the column named "Mined Through Stream-greater than 1 mi^2 of drainage" are considered ephemeral and the 50% alternative specific factor is applied. This removal affects the Colorado Plateau and Northern Rocky Mountains and Great Plains coal producing regions.

Region - Model Mine	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600	$0	0	$400	50%	1,444	0	2,156	**$1,297,600**	**$431,200**	**50%**
Central Appalachia - Contour	$600	$0	0	$400	50%	302	0	235	**$228,200**	**$47,000**	**26%**
Northern Appalachia - Contour	$0	$0	0	$400	50%	0	0	423	**$84,600**	**$84,600**	
Colorado Plateau - Area	$300	$10,000	100	$0	50%	11,605	20,107	163,326	**$5,587,021**	**$1,643,928**	**42%**
Gulf Coast - Area	$300	$10,000	100	$0	50%	12,611	0	54,904	**$4,413,511**	**$630,211**	**17%**
Illinois Basin - Area	$300	$0	0	$300	50%	15,140	0	48,809	**$11,863,350**	**$7,321,350**	**161%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100	$0	50%	12,102	26,213	182,756	**$6,029,234**	**$1,796,866**	**42%**
Northwest - Area	$235	$0	0	$235	50%	7,903	0	7,141	**$2,696,273**	**$839,068**	**45%**

Table 36: Alternative 4 Stream Restoration Costs

5.3.7. Alternative 5 Stream Restoration Costs

Alternative 5 applies to Model mines with excess spoil fills; therefore, the Central and Northern Appalachian Regions incur costs (Table 37) equal to those incurred under Alternative 4. The remaining regions have costs identical to Alternative 1.

Region - Model Mine	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600			$400	50%	1,444		2,156	**$1,297,600**	**$431,200**	**50%**
Central Appalachia - Contour	$600			$400	50%	302		235	**$228,200**	**$47,000**	**26%**
Northern Appalachia - Contour				$400	50%	0		423	**$84,600**	**$84,600**	
Colorado Plateau - Area	$300	$10,000	100			11,605	20,107		**$3,943,093**	**$0**	**0%**
Gulf Coast - Area	$300					12,611			**$3,783,300**	**$0**	**0%**
Illinois Basin - Area	$300					15,140			**$4,542,000**	**$0**	**0%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100			12,102	26,213		**$4,232,368**	**$0**	**0%**
Northwest - Area	$235					7,903			**$1,857,205**	**$0**	**0%**

Table 37: Alternative 5 Stream Restoration Costs

5.3.8. Alternative 6 Stream Restoration Costs

Alternative 6 Stream Restoration costs (Table 38) for the Appalachian Model mines are equal to Alternative 4 costs, and the non-Appalachian Model mines are equal to the Alternatives 3 costs. This is due to the one square mile watershed rule for intermittent streams for all non-Appalachian coal regions.

Region - Model Mine	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600			$400	50%	1,444		2,156	**$1,297,600**	**$431,200**	**50%**
Central Appalachia - Contour	$600			$400	50%	302		235	**$228,200**	**$47,000**	**26%**
Northern Appalachia - Contour				$400	50%	0		423	**$84,600**	**$84,600**	
Colorado Plateau - Area	$300	$10,000	100		50%	11,605	20,107	163,326	**$5,817,818**	**$1,874,725**	**48%**
Gulf Coast - Area	$300	$10,000	100		50%	12,611		54,904	**$4,413,511**	**$630,211**	**17%**
Illinois Basin - Area	$300			$300	50%	15,140		48,809	**$11,863,350**	**$7,321,350**	**161%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100		50%	12,102	26,213	182,756	**$6,330,118**	**$2,097,750**	**50%**
Northwest - Area	$235			$235	50%	7,903		7,141	**$2,696,273**	**$839,068**	**45%**

Table 38: Alternative 6 Stream Restoration Costs

5.3.9. Alternative 7 Stream Restoration Costs

Alternative 7 Stream Restoration costs (Table 39) are equal to those under Alternative 2.

Region - Model Mine	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600			$400	90%	1,444		2,156	**$1,642,560**	**$776,160**	**90%**
Central Appalachia - Contour	$600			$400	90%	302		235	**$265,800**	**$84,600**	**47%**
Northern Appalachia - Contour	$600			$400	90%	0		423	**$152,280**	**$152,280**	
Colorado Plateau - Area	$300	$10,000	100		90%	11,605	20,107	163,326	**$7,271,438**	**$3,328,345**	**84%**
Gulf Coast - Area	$300	$10,000	100		90%	12,611		54,904	**$4,917,680**	**$1,134,380**	**30%**
Illinois Basin - Area	$300			$300	90%	15,140		48,809	**$17,720,430**	**$13,178,430**	**290%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100		90%	12,102	26,213	182,756	**$7,948,141**	**$3,715,774**	**88%**
Northwest - Area	$235			$235	90%	7,903		7,141	**$3,367,527**	**$1,510,322**	**81%**

Table 39: Alternative 7 Stream Restoration Costs

5.3.10. Alternative 8 Stream Restoration Costs

Alternative 8 Stream Restoration Cost (Table 40) are equal those under Alternative 4.

Region - Model Mine	Factors								Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Eph. Stream Fee ($/ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)			
Central Appalachia - Area	$600	$0	$0	$400	50%	1,444	0	2,156	**$1,297,600**	**$431,200**	**50%**
Central Appalachia - Contour	$600	$0	$0	$400	50%	302	0	235	**$228,200**	**$47,000**	**26%**
Northern Appalachia - Contour	$0	$0	$0	$400	50%	0	0	423	**$84,600**	**$84,600**	
Colorado Plateau - Area	$300	$10,000	$100	$0	50%	11,605	20,107	163,326	**$5,587,021**	**$1,643,928**	**42%**
Gulf Coast - Area	$300	$10,000	$100	$0	50%	12,611	0	54,904	**$4,413,511**	**$630,211**	**17%**
Illinois Basin - Area	$300	$0	$0	$300	50%	15,140	0	48,809	**$11,863,350**	**$7,321,350**	**161%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	$100	$0	50%	12,102	26,213	182,756	**$6,029,234**	**$1,796,866**	**42%**
Northwest - Area	$235	$0	$0	$235	50%	7,903	0	7,141	**$2,696,273**	**$839,068**	**45%**

Table 40: Alternative 8 Stream Restoration Costs

5.3.11. Alternative 9 Stream Restoration Costs

Alternative 9 Stream Restoration Cost (Table 40are equal those under the Baseline (Alternative 1).

Region - Model Mine	Factors					Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Int. Stream Fee - Hydro. Defined ($/ft)	Ephemeral stream Restoration cost per acre	Ephemeral Corridor Width (ft)	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)			
Central Appalachia - Area	$600	$0	0	$1,444	$0	**$866,400**	**$0**	**0%**
Central Appalachia - Contour	$600	$0	0	$302	$0	**$181,200**	**$0**	**0%**
Northern Appalachia - Contour						**N/A**	**N/A**	**N/A**
Colorado Plateau - Area	$300	$10,000	100	$11,605	$20,107	**$3,943,093**	**$0**	**0%**
Gulf Coast - Area	$300	$0	0	$12,611	$0	**$3,783,300**	**$0**	**0%**
Illinois Basin - Area	$300	$0	0	$15,140	$0	**$4,542,000**	**$0**	**0%**
Northern Rocky Mountains and Great Plains - Area	$300	$10,000	100	$12,102	$26,213	**$4,232,368**	**$0**	**0%**
Northwest - Area	$235	$0	0	$7,903	$0	**$1,857,205**	**$0**	**0%**

Table 41: Alternative 9 Stream Restoration Costs

5.3.12. Summary of Stream Restoration Costs

The main differences between the Stream Restoration costs portrayed in the preceding tables are:

- The inclusion of Stream Restoration Costs for ephemeral streams in all of the Action Alternatives (Alt. 2 thru 8).
    - The percentage of the ephemeral streams that were required to be restored in the non-Appalachian Model mines. The difference between 90% in Alternatives 2 and 7, and the 50% restoration rate in Alternatives 3, 4, 5, 6 and 8.

- The assumptions made for the western Coal Regions that treated the ephemeral stream restoration as more of a reclamation project than just stream specific.

5.4. Stream Enhancement or Changes in Compensatory Mitigation Requirements

The Stream Enhancement cost assesses the costs for Clean Water Act Section 404 compensatory mitigation requirements to provide stream enhancement for ephemeral, intermittent and perennial streams that are filled during construction of excess spoil fills and coal refuse fills/impoundments.

Shown below are the variables that are considered in the calculation of the Stream Enhancement costs. Note that all costs for stream enhancement are the same for all stream classifications.

1. The definition and classification of the streams that are filled during construction of excess spoil fills and coal refuse fills/impoundments are generated as articulated in the Stream Restoration cost section. It is assumed for all underground Model mines that the facilities and fill/impoundment do not impact perennial streams.
2. Stream enhancement is calculated using a unit cost factor ($/ft). This factor applies equally to all stream impacts, regardless of stream definition.
    a. Stream Enhancements cost for Appalachia is set at $800 per foot, citing the Huntington USACE Corps District numbers reported to ELI. Originally, an in-lieu fee of $100 per linear foot was listed; however, since the time of that report, fees have escalated to a recommended $400 per linear foot, and most recently, $800 per linear foot.[22]
    b. Since no information was available for Stream Enhancement costs in the western regions or the Illinois Basin, these costs are estimated using the 2008 USACE data and best professional judgment. The Stream Enhancement cost per foot for these regions is set at $300.
    c. The Stream Enhancement cost for the Northwest region is set a $ 235 per linear foot, mirroring the Stream Restoration costs.

5.4.1. Alternative 1 Stream Enhancement Costs

In the No Action Alternative, Stream Enhancement is required for all streams impacted by excess spoil and refuse fills/impoundments based upon current CWA requirements. Alternative 1 Stream Enhancement costs are shown in Table 42.

[22] *See* the West Virginia Stream and Wetland Valuation Metric 2.0, which uses $800 as the default value for in lieu fee mitigation.

Region - Model Mine	Factors			Total Cost
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)	
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**
Central Appalachia - Contour	$800	704	6,928	**$6,105,600**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**

Table 42: Alternative 1 Stream Enhancement Costs

5.4.2. *Alternative 2 Stream Enhancement Costs*

Alternative 2 Stream Enhancement costs are shown in Table 43. The Central Appalachian surface mines are restricted from placing excess spoil in perennial and intermittent streams in Alternative 2; therefore, there are no enhancement costs for Central Appalachian surface mines.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	0	0	**$0**	**-$11,105,600**	**-100%**
Central Appalachia - Contour	$800	0	0	**$0**	**-$6,105,600**	**-100%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 43: Alternative 2 Stream Enhancement Costs

5.4.3. *Alternative 3 Stream Enhancement Costs*

Alternative 3 Stream Enhancement costs (Table 44) are equal to the No Action Alternative (Alternative 1).

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	704	6,928	**$6,105,600**	**$0**	**0%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 44: Alternative 3 Stream Enhancement Costs

5.4.4. Alternative 4 Stream Enhancement Costs

In order to comply with Alternative 4's mandate to maximize the amount of excess spoil placed on the mining bench, the Central Appalachian Contour Model mine decreased the number of stream impacts by its hollow fill. The Stream Enhancement costs for Alternative 4 are shown in Table 45, below. All other Model mines Stream Enhancement costs mirror the No Action Alternative.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	457	3,135	**$2,873,600**	**-$3,232,000**	**-53%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 45: Alternative 4 Stream Enhancement Costs

5.4.5. Alternative 5 Stream Enhancement Costs

Alternative 5 Stream Enhancement costs (Table 46) are equal to Alternative 4.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	457	3,135	**$2,873,600**	**-$3,232,000**	**-53%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 46: Alternative 5 Stream Enhancement Costs

5.4.6. Alternative 6 Stream Enhancement Costs

Alternative 6 Stream Enhancement costs (Table 47) are equal to Alternative 4.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	457	3,135	**$2,873,600**	**-$3,232,000**	**-53%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 47: Alternative 6 Stream Enhancement Costs

5.4.7. Alternative 7 Stream Enhancement Costs

Alternative 7 Stream Enhancement costs (Table 48) are equal to Alternative 4.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	457	3,135	**$2,873,600**	**-$3,232,000**	**-53%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 48: Alternative 7 Stream Enhancement Costs

5.4.8. Alternative 8 Stream Enhancement Costs

Alternative 8 Stream Enhancement costs (Table 49) are equal to Alternative 4.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	1,624	12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	457	3,135	**$2,873,600**	**-$3,232,000**	**-53%**
Central Appalachia - Room and Pillar	$800	391	863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	10,542	3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	2,097	0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	5,173	1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	2,112	299	**$723,300**	**$0**	**0%**

Table 49: Alternative 8 Stream Enhancement Costs

5.4.9. Alternative 9 Stream Enhancement Costs

Alternative 9 Stream Enhancement Costs (Table 50) are equal to the Baseline (Alternative 1) costs.

Region - Model Mine	Factors			Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Stream Enhancement Cost ($/ft)	Ephemeral Stream Filled (ft)	Intermittent or Perennial Stream Filled (ft)			
Central Appalachia - Area	$800	$1,624	$12,258	**$11,105,600**	**$0**	**0%**
Central Appalachia - Contour	$800	$704	$6,928	**$6,105,600**	**$0**	**0%**
Central Appalachia - Room and Pillar	$800	$391	$863	**$1,003,200**	**$0**	**0%**
Northern Appalachia - Longwall	$800	$10,542	$3,529	**$11,256,800**	**$0**	**0%**
Colorado Plateau - Longwall	$300	$2,097	$0	**$629,100**	**$0**	**0%**
Illinois Basin - Longwall	$300	$5,173	$1,756	**$2,078,700**	**$0**	**0%**
Illinois Basin - Room and Pillar	$300	$2,112	$299	**$723,300**	**$0**	**0%**

Table 50: Alternative 9 Stream Enhancement Costs

5.4.10. Summary Stream Enhancement Costs

The Stream Enhancement Costs for the Baseline and Action Alternatives are summarized below:

- The majority of the Stream Enhancement costs for the Action Alternatives (Alternatives 2 thru 8) mirror the No Action Alternative with a few exceptions.
  - Alternative 2 which prohibits hollow fills negates all stream impacts in the Central Appalachia surface model mines.
  - Alternatives 4 thru 8 which prohibit flat deck fills that in turn minimizes the stream impacts from the hollow fills.

5.5. Reforestation and Postmining Land Use Changes

The Reforestation and Postmining Land Use (PMLU) changes cost compares the Reforestation cost associated with previously forested lands, to the cost of common non-forestry post-mining land uses. Additionally, it accounts for riparian zone reforestation, topsoil salvage, and reclamation of organics. Reforestation and PMLU costs include:

1. Reforestation: These costs are calculated based upon a recent study comparing the costs of changing the post-mining land use from forestry to hayland/pasture.[23] The study calculated reclamation costs using a cost-engineering method based on OSMRE's bond-calculation methodology. The cost components of the study included grading, fertilizer/lime, herbaceous seeding, and tree planting. The study assumed average seeding, tree planting, labor rates, and grading rates (for a D9 bulldozer). Table 51 gives the unit cost per acre for the applicable Model mine. These costs were applied to all disturbed area outside of the riparian zone. Based upon a review of pre-mining land uses in each region, the Central Appalachia and Northern Appalachian regions typically have a forestry pre-mining land use. Reforestation costs were not calculated for

[23] Baker, K., et al., "Coal Mine Reclamation in the Southern Appalachians: Costs of Forestry Versus Hayland/Pasture" (Paper presented at the 2008 National Meeting of the American Society of Mining and Reclamation, Richmond, VA, *New Opportunities to Apply Our Science*, June 14-19, 2008. Published by ASMR, R.I. Barnhisel, Ed.)

underground mining operations because the permit acreages are small and costs are insignificant when compared to the surface disturbance associated with surface mines.

Reclamation Cost[a]		
Region/Mine	Mine Location by State	Forestry Reclamation ($/acre)
Central Appalachia Area Mine	West Virginia	$1,560.76
Central Appalachia Contour Mine	Kentucky	$1,327.35
Northern Appalachia Surface Mine	Ohio	$1,627.79

[a] Based upon study by Baker, K. et. al. , "Coal Mine Reclamation in the Southern Appalachians: Costs of Forestry Versus Hayland/Pasture" (Paper presented at the 2008 National Meeting of the American Society of Mining and Reclamation, Richmond, VA, New Opportunities to Apply Our Science, June 14-19, 2008. Published by ASMR, R.I. Barnhisel, Ed.). Costs assume use of a D-9 dozer for grading and the average seeding, tree planting, and labor rates.

Table 51: Reclamation Costs

2. Reforestation of Riparian Zones: The cost for the reforestation of the riparian zone covers all cost to reforest the area within the boundaries of the environmental zone directly adjacent to the stream channel. Reforestation of the riparian zones was calculated for Central Appalachia (CAPP) and Northern Appalachia, Colorado Plateau, Gulf Coast, Northern Rocky Mountains and Great Plains and Illinois Basin. This is calculated by two different methods depending on the scenario:
    a. For Central and Northern Appalachia, the Gulf Coast, and the Illinois Basin Regions, this number is calculated identically to the Reforestation cost using the factors in Table 51. Note that the Illinois basin and Colorado plateau regions utilized the CAPP area mine rate of $1,560.76 per acre.
    b. The Colorado Plateau and Northern Rocky Mountains and Great Plains Regions, which do not require reforestation of the mine land, an alternative method is used. This method incurs a cost for replanting of the riparian zone with tree/shrubs that are common to the area at a cost of $100 per acre.
3. Topsoil Salvage: The topsoil salvage requirement was calculated assuming an average thickness of topsoil over the disturbed area of each Model mine. The average topsoil thickness used for the Appalachian coal regions is based on observation of the clearing and grubbing operations and the geotechnical investigations observed in valley fill areas. The average topsoil thickness used for the Non-Appalachian coal regions is based on information from the websoilsurvey.nrcs.usda.gov interactive web site and professional judgment. The bulldozing cost per cubic yard of material moved for topsoil salvage was assumed to be $0.58 (mirroring the bulldozing costs included in the Haulage cost). The Topsoil Salvage cost is defined by the bulldozing cost required to pile the topsoil into a configuration to be loaded and hauled by the shovel/truck or loader/truck tandems assigned to each respective Model mine. Note that the cost of the shovel/truck or loader/truck tandems is already included in the Haulage cost. The topsoil salvage was applied to all regions except the Illinois Basin, depending on the requirements of each alternative. The Illinois Basin in general has thick topsoil (3-10 ft. thick) and it is assumed that with the abundance of prime farmland, that topsoil salvage is a baseline requirement in the region. Outside of the Model mine scenario, the cost of topsoil salvage will vary significantly on a site by site basis.
4. Reclamation of Organics: Reclamation of Organics costs are estimated by determining the cost of disposing of all organic material remaining on the disturbed area after logging. This only applies

to Central Appalachia and Northern Appalachia due to these regions being the only regions with a significant forestry pre-mining land use. Shown below is the information used for the calculation of the Reclamation of Organics:

- The USDA Live Tree Biomass[24] estimates were utilized as an overall guideline to organic material on the mine site. A value of 75 tons per acre was utilized (this is the weight of live trees above ground level).
- Number and size of trees estimated for the disturbed areas utilized data collected by MWC.[25]
- Weights of trees and average heights of trees for the Appalachian region were estimated using information documented by the USDA[26] This estimated live tree weights above the ground surface.
- Estimates of the weight of the woody portion of the root ball (beneath the ground surface) were calculated as 25% of the above ground live tree weight.[27]
- The weight of the organic material per acre to be reclaimed is calculated using the following equation:

  Weight of tree and woody root ball per acre for trees < 11 inches in diameter + Weight of woody root ball for trees > 11 inches in diameter (the above ground portion of trees > 11 inches in diameter were assumed to be logged) = Weight of organic material per acre to be reclaimed. This factor was calculated to be **31 tons/acre** of organic material to be reclaimed.
- If the alternative requires grinding of the organic material, this will cost approximately $7 per ton (Alternative 2 only), and if the alternative requires loading and hauling of the organic material off-site, this will cost approximately $4.50 per ton. These costs were applied to each Model mine in Central Appalachia and Northern Appalachia to determine the cost for the reclamation of organics.

The following additional cost factors were included in the calculations:

1. Postmining Land Use Change: A PMLU change factor of 0.7 was multiplied against the Reforestation costs for Central and Northern Appalachia. Based on professional experience, this number assumed that 70% of mines in the region are subject to reforestation due to PMLU requirements.
2. Riparian Corridor Width: The riparian corridor width is dependent on the alternative.
   a. Alternatives 1and 9 have no riparian zone corridor width applied to costs.

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[24] USDA Forest Service, Northern Research Station “Forest Inventory & Analysis” C. Kurtz Sept. 2006

[25] During 2012 and 2013, Morgan Worldwide was contracted to do HGM surveys on two West Virginia coal mine applications (approx. 50 sites). HGM (Hydrogeomorphic) is a stream assessment tool that measures the geomorphic setting, water source and hydrodynamics of the environment immediately adjacent to the stream in question. One of the criteria used in the HGM protocol is the measuring of tree diameters within the 25 foot wide riparian area on both sides of the stream channel. This tree size information is a source utilized in this appendix to confirm the USDA Biomass ton per acre graphic.

[26] USDA “Weight, Volume and Physical Properties of Major Hardwood Species in the Upland-South” A. Clark, D. Phillips, K. Frederick, Research Paper SE-257

[27] “Tree Roots: Facts and Fallacies” T.O. Perry Journal of Arboriculture 8 (8): 197-211, 1982 and Iowa State University Extension – “Tree biology: Roots in Depth”.

   b. Alternatives 2, 3, 6, 7 and 8 have a 100 ft riparian zone.
   c. Alternatives 4 and 5 have a 300 ft riparian zone.
3. Percent Ephemeral Stream Restored: Restoration rates of ephemeral streams (which influence the riparian zone reforestation) were subjected to Alternative specific factors of the following:
   a. In Alternatives 2 and 7, 90% of the mined thru ephemeral streams are required to be restored.
   b. In Alternatives 3, 4, 5, 6, and 8 50% of the mined thru ephemeral streams are required to be restored.
4. Replanting Percentage: Similar to the PMLU change factor, a replanting percentage factor of 1.5 was applied to the Riparian Zone Reforestation costs for the Central and Northern Appalachian Model mines. This number accounts for any replanting that may be required during the reclamation process to ensure the flora species' survival.

5.5.1. Alternative 1 Reforestation and Postmining Land Use Costs

Alternative 1 only applies to Central and Northern Appalachia. The total cost (Table 52) is due to the reforestation requirement, which is a function of the disturbed area, reforestation fee, and PMLU factor.

Region - Model Mine	Factors			**Total Cost**
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	
Central Appalachia - Area	$1,561	1,260	0.7	**$1,376,583**
Central Appalachia - Contour	$1,327	458	0.7	**$425,436**
Northern Appalachia - Contour	$1,628	205	0.7	**$233,276**

Table 52: Alternative 1 Reforestation and Postmining Land Use Costs

5.5.2. Alternative 2 Reforestation and Postmining Land Use Costs

5.5.2.1. Alternative 2 Reforestation Costs

Alternative 2 has requirements in addition to reforestation. These include reforestation of the riparian zone, topsoil salvage, and reclamation of organics. Reforestation costs (Table 53) are calculated for all areas outside of the intermittent/perennial and ephemeral riparian zones, assuming 90% of ephemeral streams will be restored.

Region - Model Mine	Factors							**Reforestation Cost**
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	1,116	70%	100	90%	1,444	2,156	**$1,211,073**
Central Appalachia - Contour	$1,327	371	70%	100	90%	302	235	**$343,527**
Northern Appalachia - Contour	$1,628	205	70%	100	90%	0	423	**$232,280**
Central Appalachia - Room and Pillar	$1,561	12.1						**$18,888**
Northern Appalachia - Longwall	$1,628	144.7						**$235,523**

Table 53: Alternative 2 Reforestation Costs

5.5.2.2. Alternative 2 Riparian Reforestation Costs

The Riparian Zone Reforestation costs (Table 54) are incurred within the riparian zone, which in this alternative is assumed to be 100 feet. Reforestation costs per acre do not vary from the Reforestation cost calculation; however, in Central and Northern Appalachia, a replanting percentage factor of 150% is included to account for any required replanting of vegetation.

Region - Model Mine	Factors							**Riparian Zone Reforestation Cost**
	Reforestation ($/acre)	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Replanting Percentage	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	100	90%	150%	1,444	0	2,156	**$18,192**
Central Appalachia - Contour	$1,327	100	90%	150%	302	0	235	**$2,346**
Northern Appalachia - Contour	$1,628	100	90%	150%	0	0	423	**$2,134**
Colorado Plateau - Area	$100	100	90%	N/A	11,605	20,107	163,326	**$41,025**
Gulf Coast - Area	$1,561	100	90%	N/A	12,611	0	54,904	**$222,269**
Illinois Basin - Area	$1,561	100	90%	N/A	15,140	0	48,809	**$211,674**
Northern Rocky Mountains and Great Plains - Area	$100	100	90%	N/A	12,102	26,213	182,756	**$46,555**

Table 54: Alternative 2 Riparian Zone Reforestation Costs

5.5.2.3. Alternative 2 Topsoil Salvage Costs

Under Alternative 2, Topsoil Salvage costs (Table 55) are applied over the disturbed area of each surface Model mine except for the Illinois Basin Model mine. Because of the majority of Illinois Basin Surface Mines being located in areas of naturally occurring thick soil materials, frequently qualifying as prime farmland, all of the Alternatives assume topsoil salvage and costs were not calculated as an additional cost. Topsoil thicknesses are assumed for each region.

Region - Model Mine	Factors			**Topsoil Salvage Cost**
	Disturbed Area (acres)	Average Topsoil Thickness (ft)	Bulldozer Work ($/cubic yard)	
Central Appalachia - Area	1,116	3	$0.58	**$3,133,116**
Central Appalachia - Contour	371	3	$0.58	**$1,041,471**
Northern Appalachia - Contour	205	3	$0.58	**$574,634**
Central Appalachia - Room and Pillar	12	3	$0.58	**$33,967**
Northern Appalachia - Longwall	145	3	$0.58	**$406,118**
Colorado Plateau - Area	3,311	3	$0.58	**$9,295,762**
Colorado Plateau - Longwall	44	3	$0.58	**$123,545**
Gulf Coast - Area	1,988	3	$0.58	**$5,581,836**
Northern Rocky Mountains and Great Plains - Area	6,049	2	$0.58	**$11,320,876**
Northwest - Area	497	3	$0.58	**$1,394,617**

Table 55: Alternative 2 Topsoil Salvage Costs

5.5.2.4. Alternative 2 Reclamation of Organics Cost

The final cost element for reforestation and PMLU changes is due to reclamation of organics (Table 56). This is calculated by factoring in the total weight of root balls that will be disposed of over the disturbed area. Alternative 2 requires the root balls to be ground at a cost of $7 per ton.

Region - Model Mine	Factors			**Reclamation of Organics Cost**
	Disturbed Area (acres)	Organics Weight (per acre)	Grinding Cost ($/ton)	
Central Appalachia - Area	1,116	31	$7	$242,194
Central Appalachia - Contour	371	31	$7	$80,507
Northern Appalachia - Contour	205	31	$7	$44,420
Central Appalachia - Room and Pillar	12	31	$7	$2,626
Northern Appalachia - Longwall	145	31	$7	$31,393

Table 56: Alternative 2 Reclamation of Organics Costs

5.5.2.5. Alternative 2 Summary of Reforestation and PLMU costs

The total reforestation and PMLU change cost is a sum of reforestation, riparian zone reforestation, topsoil salvage, and reclamation of organics (Table 57). Note that the ICC (Incremental Cost Change) for all non-Appalachian Model mines is equal to the total costs.

Region - Model Mine	Factors				**Total Cost**	**ICC from Alternative 1**	**Percent ICC from Alternative 1**
	Reforestation Cost	Riparian Zone Reforestation Cost	Topsoil Salvage Cost	Reclamation of Organics Cost			
Central Appalachia - Area	$1,211,073	$18,192	$3,133,116	$242,194	**$4,604,575**	**$3,227,991**	**234%**
Central Appalachia - Contour	$343,527	$2,346	$1,041,471	$80,507	**$1,467,852**	**$1,042,415**	**245%**
Northern Appalachia - Contour	$232,280	$2,134	$574,634	$44,420	**$853,468**	**$620,192**	**266%**
Central Appalachia - Room and Pillar	$18,888		$33,967	$2,626	**$55,481**	**$55,481**	**NA**
Northern Appalachia - Longwall	$235,523		$406,118	$31,393	**$673,034**	**$673,034**	**NA**
Colorado Plateau - Area		$41,025	$9,295,762		**$9,336,787**	**$9,336,787**	**NA**
Colorado Plateau - Longwall			$123,545		**$123,545**	**$123,545**	**NA**
Gulf Coast - Area		$222,269	$5,581,836		**$5,804,106**	**$5,804,106**	**NA**
Illinois Basin - Area		$211,674			**$211,674**	**$211,674**	**NA**
Northern Rocky Mountains and Great Plains - Area		$46,555	$11,320,876		**$11,367,432**	**$11,367,432**	**NA**
Northwest - Area			$1,394,617		**$1,394,617**	**$1,394,617**	**NA**

Table 57: Alternative 2 Reforestation and Postmining Land Use Costs

5.5.3. Alternative 3 Reforestation and Postmining Land Use Costs

5.5.3.1. Alternative 3 Reforestation Costs

Reforestation costs for Alternative 3 are shown below, in Table 58. Under Alternative 3, only 50% of ephemeral streams are restored. This increases the area that must be reforested under normal costs but decreases the area of riparian reforestation that incurs a 150% replanting rate. The stream lengths are adjusted based on the mine design requirements of Alternative 3.

Region - Model Mine	Factors					Reforestation Cost
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Mined Through Int. Stream - Hydro. Defined (ft)	
Central Appalachia - Area	$1,561	1,260	70%	300	1,444	**$1,365,717**
Central Appalachia - Contour	$1,327	458	70%	300	302	**$423,504**
Northern Appalachia - Contour	$1,628	205	70%	300	0	**$233,276**
Central Appalachia - Room and Pillar	$1,561	12				**$18,888**
Northern Appalachia - Longwall	$1,628	145				**$235,523**

Table 58: Alternative 3 Reforestation Costs

5.5.3.2. Alternative 3 Riparian Reforestation Costs

The unit costs for reforestation (Table 59) do not vary between alternatives; therefore, the changes in riparian zone cost are due to riparian zone width, the percent of ephemeral streams that are restored and the changes in impacted stream lengths due to changes in mine design.

Region - Model Mine	Factors					Riparian Zone Reforestation Cost
	Reforestation ($/acre)	Riparian Zone Width (ft)	Replanting Percentage	Mined Through Int. Stream - Hydro.	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	
Central Appalachia - Area	$1,561	300	150%	1,444	0	**$23,286**
Central Appalachia - Contour	$1,327	300	150%	302	0	**$4,140**
Northern Appalachia - Contour	$1,628	300	150%	0	0	**$0**
Colorado Plateau - Area	$100	300	N/A	11,605	20,107	**$21,840**
Gulf Coast - Area	$1,561	300	N/A	12,611	0	**$135,577**
Illinois Basin - Area	$1,561	300	N/A	15,140	0	**$162,765**
Northern Rocky Mountains and Great Plains - Area	$100	300	N/A	12,102	26,213	**$26,388**

Table 59: Alternative 3 Riparian Zone Reforestation Costs

5.5.3.3. Alternative 3 Topsoil Salvage Costs

Topsoil salvage is required under Alternative 3 for all Surface Model mines. Unit costs and topsoil thicknesses do not vary (Table 60).

Region - Model Mine	Factors			Topsoil Salvage Cost
	Disturbed Area (acres)	Average Topsoil Thickness (ft)	Bulldozer Work ($/cubic yard)	
Central Appalachia - Area	1,260	3	$0.58	**$3,536,511**
Central Appalachia - Contour	458	3	$0.58	**$1,285,698**
Northern Appalachia - Contour	205	3	$0.58	**$574,634**
Central Appalachia - Room and Pillar	12	3	$0.58	**$33,967**
Northern Appalachia - Longwall	145	3	$0.58	**$406,118**
Colorado Plateau - Area	3,311	3	$0.58	**$9,295,762**
Colorado Plateau - Longwall	44	3	$0.58	**$123,545**
Gulf Coast - Area	1,988	3	$0.58	**$5,581,836**
Northern Rocky Mountains and Great Plains	6,049	2	$0.58	**$11,320,876**
Northwest - Area	497	3	$0.58	**$1,394,617**

Table 60: Alternative 3 Topsoil Salvage Costs

5.5.3.4. Alternative 3 Reclamation of Organics Cost

The Reclamation of Organics costs are shown in Table 61. The requirements for organic reclamation for Alternative 2 are that the root balls are loaded and hauled within the mineral removal area.

Region - Model Mine	Factors			Reclamation of Organics Cost
	Disturbed Area (acres)	Organics Weight (tons/acre)	Load and Haul Cost ($/ton)	
Central Appalachia - Area	1,260	31	$4.5	**$175,742**
Central Appalachia - Contour	458	31	$4.5	**$63,891**
Northern Appalachia - Contour	205	31	$4.5	**$28,556**
Central Appalachia - Room and Pillar	12	31	$4.5	**$1,688**
Northern Appalachia - Longwall	145	31	$4.5	**$20,181**

Table 61: Alternative 3 Reclamation of Organics Costs

5.5.3.5. Alternative 3 Summary of Reforestation and PLMU costs

The Total cost under Alternative 3 (Table 62) accounts for all four reforestation and PMLU change factors, the greatest of which are the requirements to salvage topsoil and reforestation, where applicable.

Region - Model Mine	Factors				Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Reforestation Cost	Riparian Zone Reforestation Cost	Topsoil Salvage Cost	Reclamation of Organics Cost			
Central Appalachia - Area	$1,365,717	$23,286	$3,536,511	$175,742	**$5,101,255**	**$3,724,672**	**271%**
Central Appalachia - Contour	$423,504	$4,140	$1,285,698	$63,891	**$1,777,233**	**$1,351,797**	**318%**
Northern Appalachia - Contour	$233,276	$0	$574,634	$28,556	**$836,466**	**$603,189**	**259%**
Central Appalachia - Room and Pillar	$18,888		$33,967	$1,688	**$54,543**	**$54,543**	**NA**
Northern Appalachia - Longwall	$235,523		$406,118	$20,181	**$661,822**	**$661,822**	**NA**
Colorado Plateau - Area		$21,840	$9,295,762		**$9,317,602**	**$9,317,602**	**NA**
Colorado Plateau - Longwall			$123,545		**$123,545**	**$123,545**	**NA**
Gulf Coast - Area		$135,577	$5,581,836		**$5,717,413**	**$5,717,413**	**NA**
Illinois Basin - Area		$162,765			**$162,765**	**$162,765**	**NA**
Northern Rocky Mountains and Great Plains - Area		$26,388	$11,320,876		**$11,347,264**	**$11,347,264**	**NA**
Northwest - Area			$1,394,617		**$1,394,617**	**$1,394,617**	**NA**

Table 62: Alternative 3 Reforestation and Postmining Land Use Costs

5.5.4. Alternative 4 Reforestation and Postmining Land Use Costs

5.5.4.1. Alternative 4 Reforestation Costs

Reforestation costs for Alternative 4 are shown in Table 63. Under Alternative 4, only 50% of ephemeral streams are restored. This increases the area that must be reforested under normal costs but decreases the area of riparian reforestation that incurs a 150% replanting rate. The riparian corridor is 300 feet. The stream lengths are adjusted based on the mine design requirements of Alternative 4.

Region - Model Mine	Factors					Reforestation Cost
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Mined Through Int. Stream - Hydro. Defined (ft)	
Central Appalachia - Area	$1,561	1,260	70%	300	1,444	**$1,365,717**
Central Appalachia - Contour	$1,327	448	70%	300	302	**$414,215**
Northern Appalachia - Contour	$1,628	205	70%	300	0	**$233,276**
Central Appalachia - Room and Pillar	$1,561	12				**$18,888**
Northern Appalachia - Longwall	$1,628	145				**$235,523**

Table 63: Alternative 4 Reforestation Costs

5.5.4.2. Alternative 4 Riparian Reforestation Costs

The riparian zone width and unit costs for reforestation do not vary between alternatives; therefore, the only changes in riparian zone cost are due to the percent of ephemeral streams that are restored and the changes in impacted stream lengths due to changes in mine design (Table 64).

Region - Model Mine	Factors				Riparian Zone Reforestation Cost
	Reforestation ($/acre)	Riparian Zone Width (ft)	Replanting Percentage	Mined Through Int. Stream - Hydro.	
Central Appalachia - Area	$1,561	300	150%	1,444	**$23,286**
Central Appalachia - Contour	$1,327	300	150%	302	**$4,140**
Northern Appalachia - Contour	$1,628	300	150%	0	**$0**
Colorado Plateau - Area	$100	300	N/A	11,605	**$7,992**
Gulf Coast - Area	$1,561	300	150%	12,611	**$203,365**
Illinois Basin - Area	$1,561	300	150%	15,140	**$244,148**
Northern Rocky Mountains and Great Plains - Area	$100	300	N/A	12,102	**$8,335**

Table 64: Alternative 4 Riparian Zone Reforestation Costs

5.5.4.3. Alternative 4 Topsoil Salvage Costs

Topsoil Salvage costs (Table 65) include all Model mines under this alternative except for the Model mines in the Illinois Basin.

Region - Model Mine	Factors			Topsoil Salvage Cost
	Disturbed Area (acres)	Average Topsoil Thickness (ft)	Bulldozer Work ($/cubic yard)	
Central Appalachia - Area	1,260	3	$0.58	**$3,536,511**
Central Appalachia - Contour	448	3	$0.58	**$1,257,626**
Northern Appalachia - Contour	205	3	$0.58	**$574,634**
Central Appalachia - Room and Pillar	12	3	$0.58	**$33,967**
Northern Appalachia - Longwall	145	3	$0.58	**$406,118**
Colorado Plateau - Area	3,311	3	$0.58	**$9,295,762**
Colorado Plateau - Longwall	44	3	$0.58	**$123,545**
Gulf Coast - Area	1,988	3	$0.58	**$5,581,836**
Northern Rocky Mountains and Great Plains - Area	6,049	2	$0.58	**$11,320,876**
Northwest - Area	497	3	$0.58	**$1,394,617**

Table 65: Alternative 4 Topsoil Salvage Costs

5.5.4.4. Alternative 4 Reclamation of Organics Cost

Reclamation of Organics costs are shown in Table 66. Reclamation of organics is required for all Appalachian Model mines under Alternative 4. The underground mines must reclaim organics within the footprint of the slurry impoundment associated with the Model mine. The cost assumptions do not differ from the assumptions used in the previous alternatives.

Region - Model Mine	Factors			Reclamation of Organics Cost
	Disturbed Area (acres)	Organics Weight (tons/acre)	Load and Haul Cost ($/ton)	
Central Appalachia - Area	1,260	31	$4.5	**$175,742**
Central Appalachia - Contour	448	31	$4.5	**$62,496**
Northern Appalachia -	205	31	$4.5	**$28,556**
Central Appalachia - Room and Pillar	12	31	$4.5	**$1,688**
Northern Appalachia - Longwall	145	31	$4.5	**$20,181**

Table 66: Alternative 4 Reclamation of Organics Costs

5.5.4.5. Alternative 4 Summary of Reforestation and PLMU costs

Alternative 4 requires topsoil salvage and reclamation of organics for all of the underground Model mines. The topsoil salvage and reforestation costs are again the major factors in this alternative (Table 67).

Region - Model Mine	Factors				Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Reforestation Cost	Riparian Zone Reforestation Cost	Topsoil Salvage Cost	Reclamation of Organics Cost			
Central Appalachia -	$1,365,717	$23,286	$3,536,511	$175,742	**$5,101,255**	**$3,724,672**	**271%**
Central Appalachia - Contour	$414,215	$4,140	$1,257,626	$62,496	**$1,738,477**	**$1,313,041**	**309%**
Northern Appalachia - Contour	$233,276	$0	$574,634	$28,556	**$836,466**	**$603,189**	**259%**
Central Appalachia - Room and Pillar	$18,888		$33,967	$1,688	**$54,543**	**$54,543**	**NA**
Northern Appalachia - Longwall	$235,523		$406,118	$20,181	**$661,822**	**$661,822**	**NA**
Colorado Plateau - Area		$7,992	$9,295,762		**$9,303,755**	**$9,303,755**	**NA**
Colorado Plateau - Longwall			$123,545		**$123,545**	**$123,545**	**NA**
Gulf Coast - Area		$203,365	$5,581,836		**$5,785,202**	**$5,785,202**	**NA**
Illinois Basin - Area		$244,148			**$244,148**	**$244,148**	**NA**
Northern Rocky Mountains and Great Plains - Area		$8,335	$11,320,876		**$11,329,211**	**$11,329,211**	**NA**
Northwest - Area			$1,394,617		**$1,394,617**	**$1,394,617**	**NA**

Table 67: Alternative 4 Reforestation and Postmining Land Use Costs

5.5.5. Alternative 5 Reforestation and Postmining Land Use Costs

5.5.5.1. Alternative 5 Reforestation Costs

Alternative 5 is similar to Alternative 1, except for the additional requirements for mines with excess spoil and processing refuse storage. In the case of the Model mines, this only applies to the mines in Central and Northern Appalachia. The Reforestation costs (Table 68) are calculated similarly to the previous alternatives. The Surface Model mines have a riparian zone width of 300 feet and it is assumed that 50% of ephemeral streams are restored. For the underground mines, the reforestation unit cost is applied at a flat rate over the entire disturbed area.

Region - Model Mine	Factors							Reforestation Cost
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	1,260	70%	100	50%	1,444	2,156	**$1,370,257**
Central Appalachia - Contour	$1,327	448	70%	100	50%	302	235	**$415,253**
Northern Appalachia - Contour	$1,628	205	70%	100	50%	0	423	**$232,723**
Central Appalachia - Room and Pillar	$1,561	12						**$18,888**
Northern Appalachia - Longwall	$1,628	145						**$235,523**

Table 68: Alternative 5 Reforestation Costs

5.5.5.2. Alternative 5 Riparian Reforestation Costs

The riparian zone is reforested for Surface Model mines only in the Appalachian region (Table 69). The underground Model mines in this appendix do not mine through any streams therefore there is no restoration of the streams proposed; thus, there is no riparian zone to reforest.

Region - Model Mine	Factors						Riparian Zone Reforestation Cost
	Reforestation ($/acre)	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Replanting Percentage	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	100	50%	150%	1,444	2,156	**$13,557**
Central Appalachia - Contour	$1,327	100	50%	150%	302	235	**$1,917**
Northern Appalachia - Contour	$1,628	100	50%	150%	0	423	**$1,186**

Table 69: Alternative 5 Riparian Zone Reforestation Costs

5.5.5.3. Alternative 5 Topsoil Salvage Costs

Topsoil is salvaged over the entire disturbed area for both surface and underground mines for the Appalachian, coal regions only. The disturbed area for underground mines includes both the impoundment and the face-up area. Topsoil Salvage costs are shown in Table 70.

Region - Model Mine	Factors			Topsoil Salvage Cost
	Disturbed Area (acres)	Average Topsoil Thickness (ft)	Bulldozer Work ($/cubic yard)	
Central Appalachia - Area	1,260	3	$0.58	**$3,536,511**
Central Appalachia - Contour	448	3	$0.58	**$1,257,626**
Northern Appalachia - Contour	205	3	$0.58	**$574,634**
Central Appalachia - Room and Pillar	12	3	$0.58	**$33,967**
Northern Appalachia - Longwall	145	3	$0.58	**$406,118**

Table 70: Alternative 5 Topsoil Salvage Costs

5.5.5.4. Alternative 5 Reclamation of Organics Cost

Reclamation of Organics costs (Table 71) include costs for loading and hauling the organic material. The surface and underground mines have a $4.50 per ton fee for loading and hauling organic material.

Region - Model Mine	Factors			Reclamation of Organics Cost
	Disturbed Area (acres)	Organics Weight (tons/acre)	Load and Haul Cost ($/ton)	
Central Appalachia - Area	1,260	31	$4.5	$175,742
Central Appalachia - Contour	448	31	$4.5	$62,496
Northern Appalachia - Contour	205	31	$4.5	$28,556
Central Appalachia - Room and Pillar	12	31	$4.5	$1,688
Northern Appalachia - Longwall	145	31	$4.5	$20,181

Table 71: Alternative 5 Reclamation of Organics Costs

5.5.5.5. Alternative 5 Summary of Reforestation and PLMU costs

All four reforestation and PMLU change factors affect the Total cost for the Appalachian Model mines. The driving costs are the topsoil salvage and reforestation costs (Table 72).

Region - Model Mine	Factors				Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Reforestation Cost	Riparian Zone Reforestati	Topsoil Salvage Cost	Reclamation of Organics Cost			
Central Appalachia - Area	$1,370,257	$13,557	$3,536,511	$175,742	**$5,096,066**	**$3,719,483**	**270%**
Central Appalachia - Contour	$415,253	$1,917	$1,257,626	$62,496	**$1,737,291**	**$1,311,855**	**308%**
Northern Appalachia - Contour	$232,723	$1,186	$574,634	$28,556	**$837,098**	**$603,822**	**259%**
Central Appalachia - Room and Pillar	$18,888		$33,967	$1,688	**$54,543**	**$54,543**	**NA**
Northern Appalachia - Longwall	$235,523		$406,118	$20,181	**$661,822**	**$661,822**	**NA**

Table 72: Alternative 5 Reforestation and Postmining Land Use Costs

5.5.6. Alternative 6 Reforestation and Postmining Land Use Costs

5.5.6.1. Alternative 6 Reforestation Costs

Alternative 6 applies to mining activities within 100 feet of intermittent and perennial streams; therefore, the costs (Table 73) apply to the Surface Model mines. Reforestation costs are calculated using the 100 ft riparian zone and assuming that 50% of ephemeral streams are restored.

Region - Model Mine	Factors							**Reforestation Cost**
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	1,260	70%	100	50%	1,444	2,156	**$1,370,257**
Central Appalachia - Contour	$1,327	448	70%	100	50%	302	235	**$415,253**
Northern Appalachia - Contour	$1,628	205	70%	100	50%	0	423	**$232,723**

Table 73: Alternative 6 Reforestation Costs

5.5.6.2. Alternative 6 Riparian Reforestation Costs

The Riparian Zone Reforestation costs are shown in Table 74.

Region - Model Mine	Factors							**Riparian Zone Reforestation Cost**
	Reforestation ($/acre)	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Replanting Percentage	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	100	50%	150%	1,444	0	2,156	**$13,557**
Central Appalachia - Contour	$1,327	100	50%	150%	302	0	235	**$1,917**
Northern Appalachia - Contour	$1,628	100	50%	150%	0	0	423	**$1,186**
Colorado Plateau - Area	$100	100	50%	N/A	11,605	20,107	163,326	**$26,027**
Gulf Coast - Area	$1,561	100	50%	N/A	12,611	0	54,904	**$143,568**
Illinois Basin - Area	$1,561	100	50%	N/A	15,140	0	48,809	**$141,710**
Northern Rocky Mountains and Great Plains - Area	$100	100	50%	N/A	12,102	26,213	182,756	**$29,773**

Table 74: Alternative 6 Riparian Zone Reforestation Costs

5.5.6.3. Alternative 6 Summary of Reforestation and PLMU costs

The Total cost (Table 75) under Alternative 6 is due to Reforestation and riparian zone reforestation costs. Topsoil salvage and organic reclamation are not required.

Region	Factors		Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Reforestation Cost	Riparian Zone Reforestation			
Central Appalachia - Area	$1,370,257	$13,557	**$1,383,814**	**$7,230**	**1%**
Central Appalachia - Contour	$415,253	$1,917	**$417,170**	**-$8,267**	**-2%**
Northern Appalachia - Contour	$232,723	$1,186	**$233,908**	**$632**	**0%**
Colorado Plateau - Area		$26,027	**$26,027**	**$26,027**	**NA**
Gulf Coast - Area		$143,568	**$143,568**	**$143,568**	**NA**
Illinois Basin - Area		$141,710	**$141,710**	**$141,710**	**NA**
Northern Rocky Mountains and Great Plains - Area		$29,773	**$29,773**	**$29,773**	**NA**

Table 75: Alternative 6 Reforestation and Postmining Land Use Costs

5.5.7. Alternative 7 Reforestation and Postmining Land Use Costs

5.5.7.1. Alternative 7 Reforestation Costs

Alternative 7 Reforestation costs (Table 76) are equal to Alternative 2.

Region - Model Mine	Factors							Reforestation Cost
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro.	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	1,260	70%	100	90%	1,444	2,156	**$1,368,094**
Central Appalachia - Contour	$1,327	448	70%	100	90%	302	235	**$415,052**
Northern Appalachia - Contour	$1,628	205	70%	100	90%	0	423	**$232,280**
Central Appalachia - Room and Pillar	$1,561	12						**$18,888**
Northern Appalachia - Longwall	$1,628	145						**$235,523**

Table 76: Alternative 7 Reforestation Costs

5.5.7.2. Alternative 7 Riparian Reforestation Costs

Alternative 7 Riparian Reforestation Costs (Table 77) are equal to Alternative 2. The Riparian Zone Reforestation costs are incurred within the riparian zone, which in this alternative is assumed to be 100 feet. Reforestation costs per acre do not vary from the Reforestation cost calculation; however, in Central and Northern Appalachia, a replanting percentage factor of 150% is included to account for any required replanting of vegetation.

Region - Model Mine	Factors							Riparian Zone Reforestation Cost
	Reforestation ($/acre)	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Replanting Percentage	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	100	90%	150%	1,444	0	2,156	**$18,192**
Central Appalachia - Contour	$1,327	100	90%	150%	302	0	235	**$2,346**
Northern Appalachia - Contour	$1,628	100	90%	150%	0	0	423	**$2,134**
Colorado Plateau - Area	$100	100	90%		11,605	20,107	163,326	**$40,564**
Gulf Coast - Area	$1,561	100	90%		12,611	0	54,904	**$222,269**
Illinois Basin - Area	$1,561	100	90%		15,140	0	48,809	**$211,674**
Northern Rocky Mountains and Great Plains - Area	$100	100	90%		12,102	26,213	182,756	**$45,954**

Table 77: Alternative 7 Riparian Zone Reforestation Costs

5.5.7.3. Alternative 7 Topsoil Salvage Costs

Alternative 7 Topsoil Salvage costs (Table 78) are equal to Alternative 2, therefore Topsoil Salvage costs are applied over the disturbed area of each surface Model mine except for the Illinois Basin Model mine. Because of the majority of Illinois Basin Surface Mines being located in prime farmland, all of the Alternatives assume topsoil salvage and costs were not calculated. Topsoil thicknesses are assumed for each region.

Region - Model Mine	Factors			Topsoil Salvage Cost
	Disturbed Area (acres)	Average Topsoil Thickness (ft)	Bulldozer Work ($/cubic yard)	
Central Appalachia - Area	1,260	3	$0.58	**$3,536,511**
Central Appalachia - Contour	448	3	$0.58	**$1,257,626**
Northern Appalachia - Contour	205	3	$0.58	**$574,634**
Central Appalachia - Room and Pillar	12	3	$0.58	**$33,967**
Northern Appalachia - Longwall	145	3	$0.58	**$406,118**
Colorado Plateau - Area	3,311	3	$0.58	**$9,295,762**
Colorado Plateau - Longwall	44	3	$0.58	**$123,545**
Gulf Coast - Area	1,988	3	$0.58	**$5,581,836**
Northern Rocky Mountains and Great Plains - Area	6,049	2	$0.58	**$11,320,876**
Northwest - Area	497	3	$0.58	**$1,394,617**

Table 78: Alternative 7 Topsoil Salvage Costs

5.5.7.4. Alternative 7 Reclamation of Organics Cost

The Alternative 7 Reclamation of Organics Cost (Table 79) is a combination of the protocols set up in Alternative 2 and the mine designs exhibited in Alternative 4 for the Appalachian Surface Model mines.

Region - Model Mine	Factors			Reclamation of Organics Cost
	Disturbed Area (acres)	Organics Weight (tons/acre)	Load and Haul Cost ($/ton)	
Central Appalachia - Area	1,260	31	$4.5	**$175,742**
Central Appalachia - Contour	448	31	$4.5	**$62,496**
Northern Appalachia - Contour	205	31	$4.5	**$28,556**
Central Appalachia - Room and Pillar	12	31	$4.5	**$1,688**
Northern Appalachia - Longwall	145	31	$4.5	**$20,181**

Table 79: Alternative 7 Reclamation of Organics Costs

5.5.7.5. Alternative 7 Summary of Reforestation and PLMU costs

The Alternative 7 Reforestation and PLMU costs (Table 80) are driven by the Topsoil Salvage and reforestation costs.

Region - Model Mine	Factors				Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Reforestation Cost	Riparian Zone Reforestation Cost	Topsoil Salvage Cost	Reclamation of Organics Cost			
Central Appalachia - Area	$1,368,094	$18,192	$3,536,511	$175,742	**$5,098,539**	**$3,721,955**	**270%**
Central Appalachia - Contour	$415,052	$2,346	$1,257,626	$62,496	**$1,737,520**	**$1,312,084**	**308%**
Northern Appalachia - Contour	$232,280	$2,134	$574,634	$28,556	**$837,604**	**$604,328**	**259%**
Central Appalachia - Room and Pillar	$18,888		$33,967	$1,688	**$54,543**	**$158,220**	**NA**
Northern Appalachia - Longwall	$235,523		$406,118	$20,181	**$661,822**	**$880,630**	**NA**
Colorado Plateau - Area		$40,564	$9,295,762		**$9,336,326**	**$9,336,326**	**NA**
Colorado Plateau - Longwall			$123,545		**$123,545**	**$185,556**	**NA**
Gulf Coast - Area		$222,269	$5,581,836		**$5,804,106**	**$5,804,106**	**NA**
Illinois Basin - Area		$211,674			**$211,674**	**$211,674**	**NA**
Northern Rocky Mountains and Great Plains - Area		$45,954	$11,320,876		**$11,366,830**	**$11,366,830**	**NA**
Northwest - Area			$1,394,617		**$1,394,617**	**$1,394,617**	**NA**

Table 80: Alternative 7 Summary of Reforestation/PLMU Costs

5.5.8. Alternative 8 Reforestation and Postmining Land Use Costs

5.5.8.1. Alternative 8 Reforestation Costs

Reforestation costs for Alternative 8 are shown in Table 81. Under Alternative 8, only 50% of ephemeral streams are restored. This increases the area that must be reforested under normal costs but decreases the area of riparian reforestation that incurs a 150% replanting rate. The riparian corridor is 300 feet. The stream lengths are adjusted based on the mine design requirements of Alternative 8.

Region - Model Mine	Factors							Reforestation Cost
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	1,260	70%	100	50%	1,444	2,156	**$1,370,257**
Central Appalachia - Contour	$1,327	448	70%	100	50%	302	235	**$415,253**
Northern Appalachia - Contour	$1,628	205	70%	100	50%	0	423	**$232,723**
Central Appalachia - Room and Pillar	$1,561	12	0%	0	0	0	0	**$18,888**
Northern Appalachia - Longwall	$1,628	145	0%	0	0	0	0	**$235,523**

Table 81: Alternative 8 Reforestation Costs

5.5.8.2. Alternative 8 Riparian Reforestation Costs

The riparian zone width and unit costs for reforestation do not vary between alternatives; therefore, the only changes in riparian zone cost are due to the percent of ephemeral streams that are restored and the changes in impacted stream lengths due to changes in mine design (Table 82).

Region - Model Mine	Factors							Riparian Zone Reforestation Cost
	Reforestation ($/acre)	Riparian Zone Width (ft)	Percent of Ephemeral Stream Restored	Replanting Percentage	Mined Through Int. Stream - Hydro. Defined (ft)	Mined Through Stream - greater than 1 mi^2 of drainage	Mined Through Eph. Stream (ft)	
Central Appalachia - Area	$1,561	100	50%	150%	1,444	0	2,156	**$13,557**
Central Appalachia - Contour	$1,327	100	50%	150%	302	0	235	**$1,917**
Northern Appalachia - Contour	$1,628	100	50%	150%	0	0	423	**$1,186**
Colorado Plateau - Area	$100	100	50%		11,605	20,107	163,326	**$26,027**
Gulf Coast - Area	$1,561	100	50%		12,611	0	54,904	**$143,568**
Illinois Basin - Area	$1,561	100	50%		15,140	0	48,809	**$141,710**
Northern Rocky Mountains and Great Plains - Area	$100	100	50%		12,102	26,213	182,756	**$29,773**

Table 82: Alternative 8 Riparian Zone Reforestation Costs

5.5.8.3. Alternative 8 Topsoil Salvage Costs

Topsoil Salvage costs (Table 83) include all Model mines under this alternative except for the Model mines in the Illinois Basin.

Region - Model Mine	Factors			Topsoil Salvage Cost
	Disturbed Area (acres)	Average Topsoil Thickness (ft)	Bulldozer Work ($/cubic yard)	
Central Appalachia - Area	1,260	3	$0.58	**$3,536,511**
Central Appalachia - Contour	448	3	$0.58	**$1,257,626**
Northern Appalachia - Contour	205	3	$0.58	**$574,634**
Central Appalachia - Room and Pillar	12	3	$0.58	**$33,967**
Northern Appalachia - Longwall	145	3	$0.58	**$406,118**
Colorado Plateau - Area	3,311	3	$0.58	**$9,295,762**
Colorado Plateau - Longwall	44	3	$0.58	**$123,545**
Gulf Coast - Area	1,988	3	$0.58	**$5,581,836**
Northern Rocky Mountains and Great Plains - Area	6,049	2	$0.58	**$11,320,876**
Northwest - Area	497	3	$0.58	**$1,394,617**

Table 83: Alternative 8 Topsoil Salvage Costs

5.5.8.4. Alternative 8 Reclamation of Organics Cost

Reclamation of Organics costs are shown in Table 84. Reclamation of organics is required for all Appalachian Model mines under Alternative 8. The underground mines must reclaim organics within the footprint of the slurry impoundment associated with the Model mine. The cost assumptions do not differ from the assumptions used in the previous alternatives.

Region - Model Mine	Factors			Reclamation of Organics Cost
	Disturbed Area (acres)	Organics Weight (tons/acre)	Load and Haul Cost ($/ton)	
Central Appalachia - Area	1,260	31	$4.5	**$175,742**
Central Appalachia - Contour	448	31	$4.5	**$62,496**
Northern Appalachia -	205	31	$4.5	**$28,556**
Central Appalachia - Room and Pillar	12	31	$4.5	**$1,688**
Northern Appalachia - Longwall	145	31	$4.5	**$20,181**

Table 84: Alternative 8 Reclamation of Organics Costs

5.5.8.5. Alternative 8 Summary of Reforestation and PLMU costs

Alternative 8 requires topsoil salvage and reclamation of organics for all of the underground Model mines. The topsoil salvage and reforestation costs are again the major factors in this alternative (Table 85).

Region - Model Mine	Factors				Total Cost	ICC from Alternative 1	Percent ICC from Alternative 1
	Reforestation Cost	Riparian Zone Reforestation Cost	Topsoil Salvage Cost	Reclamation of Organics Cost			
Central Appalachia -	$1,370,257	$13,557	$3,536,511	$175,742	**$5,096,066**	**$3,719,483**	**271%**
Central Appalachia - Contour	$415,253	$1,917	$1,257,626	$62,496	**$1,737,291**	**$1,311,855**	**316%**
Northern Appalachia - Contour	$232,723	$1,186	$574,634	$28,556	**$837,098**	**$603,822**	**259%**
Central Appalachia - Room and Pillar	$18,888		$33,967	$1,688	**$54,543**	**$54,543**	**NA**
Northern Appalachia - Longwall	$235,523		$406,118	$20,181	**$661,822**	**$661,822**	**NA**
Colorado Plateau - Area		$26,027	$9,295,762		**$9,321,789**	**$9,321,789**	**NA**
Colorado Plateau - Longwall			$123,545		**$123,545**	**$123,545**	**NA**
Gulf Coast - Area		$143,568	$5,581,836		**$5,725,405**	**$5,725,405**	**NA**
Illinois Basin - Area		$141,710			**$141,710**	**$141,710**	**NA**
Northern Rocky Mountains and Great Plains - Area		$29,773	$11,320,876		**$11,350,650**	**$11,350,650**	**NA**
Northwest - Area			$1,394,617		**$1,394,617**	**$1,394,617**	**NA**

Table 85: Alternative 8 Reforestation and Postmining Land Use Costs

5.5.9. Alternative 9 Reforestation and Postmining Land Use Costs

Alternative 9 only applies to Central and Northern Appalachia. The total cost (Table 86) is due to the reforestation requirement, which is a function of the disturbed area, reforestation fee, and PMLU factor.

Region - Model Mine	Factors			Total Cost
	Reforestation ($/acre)	Disturbed Area (acres)	PMLU Change	
Central Appalachia - Area	$1,561	1,260	0.7	**$1,376,583**
Central Appalachia - Contour	$1,327	458	0.7	**$425,436**
Northern Appalachia - Contour	$1,628	205	0.7	**$233,276**

Table 86: Alternative 9 Reforestation and Postmining Land Use Costs

5.6. Enhanced Permitting

Enhanced Permitting would include the additional Technical, Water, Geochemical, and Best Management Practices costs that would be associated with mine permitting in areas of sensitive or unique water environments. The costs will apply to Alternatives 4 and 7 only. Listed below are some typical tasks that may be initiated under an enhanced permitting designation.

1) Using the original consultant's report, conduct a thorough analysis of the receiving watershed. The analysis will include the location and type of current and past disturbances in the watershed and other activities that may affect water quality.
2) Use measured stream flows and recorded storm hydrographs to develop pre-mining hydrologic models.
3) Develop a model showing seasonal groundwater fluctuations. Correlate results with precipitation events and groundwater quality.
4) When feasible, design excess disposal fills on the up-dip (groundwater flow) side of the proposed operation.
5) Based on existing conditions and all pertinent constraints, establish clear environmental goals for the proposed operation.
6) Develop reclamation goals by planning timely redistribution of topsoil and organics, contemporaneous plantings, and any related actions that would help reduce water quality degradation from the proposed operation. These goals should be specific to the proposed operation and its conditions.
7) Develop detailed mine plan in six month increments showing disturbed and reclaimed areas, roads, sediment controls, topsoil storage, fills, BMPs, etc. Integrate mine plan with environmental goals. For instance, the mine plan should meet production requirements while minimizing unvegetated backfill.
8) Use pre-mining hydrologic models and detailed mine plans to assess flood potential and need for controls.
9) Use pre-mining hydrologic models and detailed mine plans to project sediment loads and design sediment control structures. Recommend use of temporary sediment controls.
10) Use on-bench ponds, where possible, in conjunction with in-stream ponds below fills. Design on-bench ponds for full sediment load. Maintain on-bench ponds with a low permanent pool to allow recirculation from in-stream ponds as needed. Overdesign ponds to hold greater than minimum sediment capacity.
11) Write comprehensive permit sections to address the requirements of Alternative 7. Use background data and a detailed mine plan to demonstrate how environmental goals will be achieved.
12) Implement fish and wildlife enhancement measures commensurate with the long-term impact of mining. Locate the stream enhancement in the same or adjacent watershed as the forest, loss of other native plant communities, or the filling of a segment of an intermittent or perennial stream
13) Due to its detailed nature, additional review time is expected for Alternative 7. For this estimate, the review time is projected to increase by a total of 400 hours for all regulatory agencies.

NOTE: The tasks listed above are general and may be modified and/or expanded for a particular operation.

The enhanced permitting costs include technical, water, geochemical, and best management practice (BMP) costs. These are broken down into subcategories as shown in Table 87.

<table>
<tr><th>Technical Costs</th><th>Water costs</th><th>Geochemical Costs</th><th>BMP Costs</th></tr>
<tr><td>Detailed watershed surveys</td><td>Additional water quality monitoring</td><td rowspan="2">Additional pre-mining drilling, geochemical testing and block modeling</td><td>Additional temporary sediment controls</td></tr>
<tr><td>Planning and permitting</td><td rowspan="4">Drill wells, install apparatus, monitor groundwater levels and hydrology</td><td>Haulroad base stabilization</td></tr>
<tr><td rowspan="3">Monitor and manage revegetation and growth</td><td rowspan="3">Additional during mining drilling, geochemical testing and update block model</td><td>Additional sediment ponds and pump-back systems</td></tr>
<tr><td>Temporary erosion control blankets on critical slope areas</td></tr>
<tr><td>Valley fill basal flow pump-back system</td></tr>
</table>

Table 87: Enhanced Mitigation Costs

5.6.1. Technical Costs

The detailed watershed survey primarily concerns the past and current activities in the watershed that may affect water quality and runoff. Preferably, areas of disturbance are surveyed and mapped in a GIS database.

- Costs are approximated by multiplying the disturbed area by a cost per acre factor ($50/hr).

Planning and permitting involves formulating a detailed mine plan and completing comprehensive permitting work. The cost includes technician support and engineering.

- Technician costs are found by multiplying disturbed area by hours required for enhanced permitting per acre (0.45 hours) and by the technician hourly rate ($30/hr).
- Engineering costs are calculated using the disturbed area, engineering hours per acre (1.6), and the engineering hourly rate ($50/hour)

Under monitoring and managing revegetation and tree planting, it is assumed that a technician will spend 10 hours per month through bond release monitoring and managing revegetation and tree planting.

- This cost is calculated over the full mine life, including a five year postmining time frame using the technician rate of $30 per hour.

5.6.1.1. Alternative 4 Technical Costs

The Enhanced Permitting Technical costs for Alternative 4 are shown below, in Table 88.

Region - Model Mines	Factors			Technical Costs
	Detailed Watershed Surveys	Planning and Permitting	Monitor and manage revegetation and tree growth	
Central Appalachia - Area	$62,990	$117,791	$75,913	**$256,694**
Central Appalachia - Contour	$22,400	$41,888	$54,000	**$118,288**
Northern Appalachia - Area	$10,235	$19,139	$46,800	**$76,174**
Colorado Plateau - Area	$165,570	$309,616	$118,582	**$593,768**
Gulf Coast - Area	$99,420	$185,915	$62,400	**$347,735**
Illinois Basin - Area	$53,355	$99,774	$62,640	**$215,769**
Northern Rocky Mountains and Great Plains - Area	$302,460	$565,600	$158,532	**$1,026,593**
Northwest - Area	$24,840	$46,451	$84,600	**$155,891**

Table 88: Enhanced Permitting: Alternative 4 Technical Costs

5.6.1.2. Alternative 7 Technical Costs

The Enhanced Permitting Technical costs for Alternative 7 are shown in Table 89.

Region - Model Mines	Factors			Technical Costs
	Detailed Watershed Surveys	Planning and Permitting	Monitor and manage revegetation and tree growth	
Central Appalachia - Area	$62,990	$117,791	$75,913	**$256,694**
Central Appalachia - Contour	$22,400	$41,888	$54,000	**$118,288**
Northern Appalachia - Area	$10,235	$19,139	$46,800	**$76,174**
Colorado Plateau - Area	$165,570	$309,616	$118,582	**$593,768**
Gulf Coast - Area	$99,420	$185,915	$62,400	**$347,735**
Illinois Basin - Area	$53,355	$99,774	$62,640	**$215,769**
Northern Rocky Mountains and Great Plains - Area	$302,460	$565,600	$158,532	**$1,026,593**
Northwest - Area	$24,840	$46,451	$84,600	**$155,891**

Table 89: Enhanced Permitting: Alternative 7 Technical Costs

5.6.2. Water Costs

Under additional water quality monitoring, surface water and groundwater samples are grouped together. The mine operator can determine how these samples should be split between groundwater and surface water, according to their local needs. The examples shown below are for 10 additional water monitoring samples for a 1000 acres of disturbance) that are evenly divided between groundwater and surface water (i.e. 5 surface water samples and 5 groundwater samples.)

- Labor costs for water monitoring and analysis are calculated at 20 hours per month at technician rates ($30/hr) over the life of the mine, including two years of premining monitoring and five years of postmining monitoring.
- For additional water sampling and testing, a regionally designated number of additional water samples per 1000 acres is assumed (10 samples) at a unit cost per sample ($200/sample). It is

also assumed that one sample would be taken once per month over mine life, including two years of premining monitoring and five years of postmining monitoring.

The following applies to the cost for drilling wells, installing apparatus, and monitoring groundwater levels and hydrology. For the cost to drill wells to monitor groundwater levels, it is assumed domestic wells will not be available for this purpose.

- The Total cost for well installation is calculated by multiplying the unit drilling cost ($50/ft) by the total well depth, assuming five wells per 1000 acres of disturbed area at an average depth of 300 feet.
- For the installation of apparatus, the costs includes stream weirs and rainfall gauges to monitor rainfall and runoff responses in each watershed. Both types of gauges are automatic continuous recording devices with transmitting capabilities.
  - The streamflow gauge (weirs) cost also assumes there will be an average of two weirs per 1000 acres of disturbed area. Streamflow gauges will be installed prior to disturbance. The cost is calculated by multiplying the installed cost of the gauges ($10,000/weir) by the number of weirs over the disturbed area. [Streamflow gauge cost x # of Streamflow gauges per 1000 acres x Disturbed area/1000 acres = $].
  - The rainfall gauge cost assumes the required number of rainfall gauges is two gauges per 1000 acres of disturbed area. The Total cost of the gauges is equal to the installed cost of the gauges ($10,000/gauge) multiplied by the number of gauges over the disturbed area.
- For the groundwater level monitoring, a technician monitors and analyzes groundwater levels, rainfall, and surface water flows through bond release.
  - This cost assumes a technician ($30/hr) will work two days per month, at 10 hours per shift, to monitor and analyze rainfall, runoff, and groundwater levels. The monitoring will begin two years prior to mining and continue five years post-mining.

5.6.2.1. Alternative 4 Water Costs

The Enhanced Permitting Water costs for Alternative 4 are listed in Table 90.

Region - Model Mines	Factors		Water Costs
	Additional Water Quality Monitoring	Drill wells, install apparatus, monitor groundwater levels and hydrology	
Central Appalachia - Area	$864,265	$357,277	**$1,221,542**
Central Appalachia - Contour	$305,184	$207,920	**$513,104**
Northern Appalachia - Area	$181,692	$161,541	**$343,233**
Colorado Plateau - Area	$3,028,323	$702,253	**$3,730,576**
Gulf Coast - Area	$1,061,818	$406,533	**$1,468,350**
Illinois Basin - Area	$636,522	$301,197	**$937,718**
Northern Rocky Mountains and Great Plains - Area	$7,015,119	$1,119,196	**$8,134,315**
Northwest - Area	$487,642	$291,732	**$779,374**

Table 90: Enhanced Permitting: Alternative 4 Water Costs

5.6.2.2. Alternative 7 Water Costs

The Enhanced Permitting Water costs for Alternative 7 are listed in Table 91.

Region - Model Mines	Factors		Water Costs
	Additional Water Quality Monitoring	Drill wells, install apparatus, monitor groundwater levels and hydrology	
Central Appalachia - Area	$864,265	$357,277	**$1,221,542**
Central Appalachia - Contour	$305,184	$207,920	**$513,104**
Northern Appalachia - Area	$181,692	$161,541	**$343,233**
Colorado Plateau - Area	$3,028,323	$702,253	**$3,730,576**
Gulf Coast - Area	$1,061,818	$406,533	**$1,468,350**
Illinois Basin - Area	$636,522	$301,197	**$937,718**
Northern Rocky Mountains and Great Plains - Area	$7,015,119	$1,119,196	**$8,134,315**
Northwest - Area	$487,642	$291,732	**$779,374**

Table 91: Enhanced Permitting: Alternative 7 Water Costs

5.6.3. Geochemical Costs

Geochemical costs are applied prior to- and during mining operations.

- Pre-mining drilling costs are calculated assuming that pre-mining geochemical drilling will be by core drill. The cost of core drilling is calculated assuming five additional premining drill holes per 1000 acres will be drilled at an average depth of 200 feet at a cost of $50 per foot. The sample and testing costs are calculated assuming that the entire length of additional premining core holes will be sampled every five feet at a rate of $50 per hour. Finally, for pre-mining analysis, the original block model will be created at a onetime cost for engineering. The cost is calculated assuming one engineer will build the block model at $50 per hour over a 200 hour time period.
- During-mining geochemical drilling will be accomplished using a rotary drill with chip sampling. This occurs during the normal mining process; therefore, it is assumed no additional drill costs will be incurred. To calculate the during-mining costs, it is assumed that 5% of the total overburden is potentially toxic material and subject to required testing. It is also assumed that one hole will be sampled for every 50,000 bank cubic yards of potentially toxic material. The cost calculation assumes each hole will be sampled every five feet, and each sample will cost $50. Finally, the time to update the during-mining block model and analyze results is assumed to be 5 hours per month at the technician rate ($30/hr) over the operating life of the mine.

5.6.3.1. Alternative 4 Geochemical Costs

The Enhanced Permitting Geochemical costs for Alternative 4 are listed in Table 92, below.

Region - Model Mines	Factors		Geochemical Costs
	Additional During mining Drilling, Geochemical Testing & Update Block Model	Additional During mining Drilling, Geochemical Testing & Update Block Model	
Central Appalachia - Area	$85,588	$324,317	**$409,905**
Central Appalachia - Contour	$36,880	$51,360	**$88,240**
Northern Appalachia - Area	$22,282	$20,400	**$42,682**
Colorado Plateau - Area	$208,684	$503,011	**$711,695**
Gulf Coast - Area	$129,304	$232,040	**$361,344**
Illinois Basin - Area	$74,026	$118,640	**$192,666**
Northern Rocky Mountains and Great Plains - Area	$372,952	$717,826	**$1,090,778**
Northwest - Area	$39,808	$33,300	**$73,108**

Table 92: Enhanced Permitting: Alternative 4 Geochemical Costs

5.6.3.2. Alternative 7 Geochemical Costs

The Enhanced Permitting Geochemical costs for Alternative 7 are listed in Table 93, below.

Region - Model Mines	Factors		Geochemical Costs
	Additional During mining Drilling, Geochemical Testing & Update Block Model	Additional During mining Drilling, Geochemical Testing & Update Block Model	
Central Appalachia - Area	$85,588	$324,317	**$409,905**
Central Appalachia - Contour	$36,880	$51,360	**$88,240**
Northern Appalachia - Area	$22,282	$20,400	**$42,682**
Colorado Plateau - Area	$208,684	$503,011	**$711,695**
Gulf Coast - Area	$129,304	$232,040	**$361,344**
Illinois Basin - Area	$74,026	$118,640	**$192,666**
Northern Rocky Mountains and Great Plains - Area	$372,952	$717,826	**$1,090,778**
Northwest - Area	$39,808	$33,300	**$73,108**

Table 93: Enhanced Permitting: Alternative 7 Geochemical Costs

5.6.4. Best Management Practice Costs

BMP costs are broken down into five categories.

- BMP No. 1 outlines additional temporary sediment controls. For the installation of temporary sediment controls, it is assumed that 50 additional temporary sediment controls per 1000 acres are used for the life of project. These require a two man crew to install each control in one 10-hour shift at the rate of $30 per hour (Materials costs are not considered). For maintenance of temporary sediment controls, costs are calculated assuming four hours per week for inspection and maintenance of all controls over the producing life of the mine.
- BMP No. 2 requires haulroad base stabilization, which assumes all primary haulroads will have geogrid installed to stabilize their road bases. The average cost of geogrid is assumed to be $15 per foot for a 50 foot wide road surface. It is assumed that average length of road per 1000 acres that will require stabilization is 50,000 feet.
- BMP No. 3 requires additional sediment ponds and pump-back systems. This BMP assumes an additional volume of sediment control capacity of 10 acre-feet per 1000 acres of disturbed area

and $2 per bank cubic yard for excavation costs. Any pumping systems are considered pre-existing at no additional cost.

- BMP No. 4 outlines costs for temporary erosion control blankets on critical slope areas. The cost for blankets is $1.75 per square yard. Critical areas are 500 feet x 500 feet and are located on steep slopes where rapid erosion may occur during storm events. The number of critical areas is regionally determined. The Northern Rocky Mountains and Great Plains, Colorado Plateau, and Northwest surface mines have one critical area per 1000 acres, while the Central and Northern Appalachian surface mines have three critical areas per 1000 acres. The Illinois Basin and Gulf Coast mines do not have critical slope areas.
- BMP No. 5 refers to valley fill basal flow pump-back systems and only applies to operations with valley fills (Central Appalachia in the case of the Model mines). Basal flow pump-back systems are installed on an as-needed basis. The results of the water quality sampling program will determine the need for this BMP. These systems are considered a temporary control for a limited problem. Other procedures, such as comprehensive testing and special handling of toxic materials, are assumed to have handled nearly all related issues. In the costs analysis, basal flow pump-back systems are added at a rate of two systems per 1000 acres. The costs assume $200,000 per system with each system operating 5% of time. Therefore, it is assumed that yearly operation and maintenance cost over the producing life of the mine is 5% of the system cost ($10,000 per year).

5.6.4.1. Alternative 4 Best Management Practices Costs

The Enhanced Permitting Best Management Practices costs for Alternative 4 are listed in Table 94.

Region - Model Mines	Factors					BMP Costs
	BMP No. 1 Additional Temporary Sediment Controls	**BMP No. 2** Haulroad Base Stabilization	**BMP No. 3** Additional Sediment Ponds & Pump-Back Systems	**BMP No. 4** Temporary erosion control blankets on critical slope areas	**BMP No. 5** Valley Fill Basal Flow Pump-Back System	
Central Appalachia - Area	$138,177	$94,485	$40,650	$183,721	$909,247	**$1,366,279**
Central Appalachia - Contour	$75,840	$33,600	$14,455	$65,333	$268,800	**$458,029**
Northern Appalachia - Area	$56,061	$15,353	$6,605	$29,852	$0	**$107,871**
Colorado Plateau - Area	$273,684	$248,355	$106,848	$160,971	$0	**$789,857**
Gulf Coast - Area	$136,612	$149,130	$64,159	$0	$0	**$349,901**
Illinois Basin - Area	$109,389	$80,033	$34,432	$0	$0	**$223,853**
Northern Rocky Mountains and Great Plains - Area	$425,065	$453,690	$195,188	$294,058	$0	**$1,368,001**
Northwest - Area	$130,344	$37,260	$16,030	$24,150	$0	**$207,784**

Table 94: Enhanced Permitting: Alternative 4 Best Management Practices Costs

5.6.4.2. Alternative 7 Best Management Practices Costs

The Enhanced Permitting Best Management Practices costs for Alternative 7 are listed in Table 95.

Region - Model Mines	Factors					BMP Costs
	BMP No. 1 Additional Temporary Sediment Controls	**BMP No. 2** Haulroad Base Stabilization	**BMP No. 3** Additional Sediment Ponds & Pump-Back Systems	**BMP No. 4** Temporary erosion control blankets on critical slope areas	**BMP No. 5** Valley Fill Basal Flow Pump-Back System	
Central Appalachia - Area	$138,177	$94,485	$40,650	$183,721	$909,247	**$1,366,279**
Central Appalachia - Contour	$75,840	$33,600	$14,455	$65,333	$268,800	**$458,029**
Northern Appalachia - Area	$56,061	$15,353	$6,605	$29,852	$0	**$107,871**
Colorado Plateau - Area	$273,684	$248,355	$106,848	$160,971	$0	**$789,857**
Gulf Coast - Area	$136,612	$149,130	$64,159	$0	$0	**$349,901**
Illinois Basin - Area	$109,389	$80,033	$34,432	$0	$0	**$223,853**
Northern Rocky Mountains and Great Plains - Area	$425,065	$453,690	$195,188	$294,058	$0	**$1,368,001**
Northwest - Area	$130,344	$37,260	$16,030	$24,150	$0	**$207,784**

Table 95: Enhanced Permitting: Alternative 7 Best Management Practices Costs

5.6.5. Total Enhanced Permitting Costs

The overall cost for enhanced permitting is multiplied by an Applicability factor based on the following criteria. The Applicability factor is equivalent to the estimated percentage of mines in the region that fall under each criterion.

- Criterion No. 1 applies to surface mining activities (including surface activities of underground mining) in pristine or unique hydrologic environments (any unique historic, hydrologic, geologic, or other natural areas, with a special designation status.
- Criterion No. 2 applies to proposed operations in strata that have been known to produce acid or toxic mine drainage to ensure that mining and reclamation can be accomplished such that active or post-mining water quality does not cause material damage to the hydrologic balance outside the permit area.
- Criterion No. 3 applies to mining operations in watersheds with impaired waters or streams when the parameter(s) causing the impaired listing (i.e. 303D Streams) are reasonably expected to be exacerbated by a proposed coal mine activity within a watershed or impaired stream. However, if the impairment is not reasonably expected to adversely impact the impaired status or condition of the stream, then these enhanced requirements would not apply.
- Criterion No. 4 applies to proposed operations on steep slope (areas with slopes greater than 20 degrees on more than 10% of the proposed disturbed acreage) or operations that propose to place excess spoil or coal mine refuse in intermittent or perennial streams or their buffer zones. These areas require an accurate premining baseline topographic model with an analysis of the postmining slope configuration and stability. Impacts from placement of excess spoil or coal refuse material in an intermittent and perennial stream must be offset through fish and wildlife enhancement requirements.

5.6.5.1. Alternative 4 Applicability Factors

The Enhanced Permitting Applicability factors for Alternative 4 are shown in Table 96.

Region - Model Mines	Factors				Maximum Applicability
	Criterion No. 1 Surface Mining in Pristine or Unique Environments	**Criterion No. 2** Surface Mining in Strata Known for Producing Acid or Toxic Drainage	**Criterion No. 3** Surface Mining in Watersheds with Impared Streams	**Criterion No. 4** Surface Mining on Steep Slopes or with Excess Spoil Placement in Per. or Int. Streams	
Central Appalachia - Area	5%	95%	60%	0%	**95%**
Central Appalachia - Contour	5%	95%	60%	0%	**95%**
Northern Appalachia - Area	5%	85%	60%	0%	**85%**
Colorado Plateau - Area	60%	5%	5%	0%	**60%**
Gulf Coast - Area	20%	5%	10%	0%	**20%**
Illinois Basin - Area	10%	5%	5%	0%	**10%**
Northern Rocky Mountains and Great Plains - Area	20%	5%	5%	0%	**20%**
Northwest - Area	5%	5%	10%	0%	**10%**

Table 96: Enhanced Permitting: Alternative 4 Applicability Factor

5.6.5.2. Alternative 7 Applicability Factor

The Enhanced Permitting Applicability factors for Alternative 7 are shown in Table 97.

Region - Model Mines	Factors				Maximum Applicability
	Criterion No. 1 Surface Mining in Pristine or Unique Environments	**Criterion No. 2** Surface Mining in Strata Known for Producing Acid or Toxic Drainage	**Criterion No. 3** Surface Mining in Watersheds with Impared Streams	**Criterion No. 4** Surface Mining on Steep Slopes or with Excess Spoil Placement in Per. or Int. Streams	
Central Appalachia - Area	5%	75%	75%	95%	**95%**
Central Appalachia - Contour	5%	75%	75%	95%	**95%**
Northern Appalachia - Area	5%	75%	75%	85%	**85%**
Colorado Plateau - Area	60%	5%	5%	0%	**60%**
Gulf Coast - Area	20%	5%	10%	0%	**20%**
Illinois Basin - Area	10%	5%	5%	0%	**10%**
Northern Rocky Mountains and Great Plains - Area	20%	5%	5%	0%	**20%**
Northwest - Area	5%	5%	10%	0%	**10%**

Table 97: Enhanced Permitting: Alternative 7 Applicability Factor

The criteria that apply to each region are assigned an applicability percent factor. The greatest percentage between each criterion is applied to the Total cost of each enhanced permitting category. These costs are summed to give the enhanced permitting cost. The Enhanced Permitting Total costs for Alternative 4 are listed in Table 98.

Region - Model Mines	Factors					Total Cost
	Technical Costs	Water Costs	Geochemical Costs	BMP Costs	Maximum Applicability	
Central Appalachia - Area	$256,694	$1,221,542	$409,905	$1,366,279	95%	**$3,091,699**
Central Appalachia - Contour	$118,288	$513,104	$88,240	$458,029	95%	**$1,118,778**
Northern Appalachia - Area	$76,174	$343,233	$42,682	$107,871	85%	**$484,466**
Colorado Plateau - Area	$593,768	$3,730,576	$711,695	$789,857	60%	**$3,495,538**
Gulf Coast - Area	$347,735	$1,468,350	$361,344	$349,901	20%	**$505,466**
Illinois Basin - Area	$215,769	$937,718	$192,666	$223,853	10%	**$157,001**
Northern Rocky Mountains and Great Plains - Area	$1,026,593	$8,134,315	$1,090,778	$1,368,001	20%	**$2,323,937**
Northwest - Area	$155,891	$779,374	$73,108	$207,784	10%	**$121,616**

Table 98: Enhanced Permitting: Alternative 4 Total Costs

The Enhanced Permitting Enhanced Permitting Total costs for Alternative 7 are listed in Table 99.

Region - Model Mines	Factors					Total Cost
	Technical Costs	Water Costs	Geochemical Costs	BMP Costs	Maximum Applicability	
Central Appalachia - Area	$256,694	$1,221,542	$409,905	$1,366,279	95%	**$3,091,699**
Central Appalachia - Contour	$118,288	$513,104	$88,240	$458,029	95%	**$1,118,778**
Northern Appalachia - Area	$76,174	$343,233	$42,682	$107,871	85%	**$484,466**
Colorado Plateau - Area	$593,768	$3,730,576	$711,695	$789,857	60%	**$3,495,538**
Gulf Coast - Area	$347,735	$1,468,350	$361,344	$349,901	20%	**$505,466**
Illinois Basin - Area	$215,769	$937,718	$192,666	$223,853	10%	**$157,001**
Northern Rocky Mountains and Great Plains - Area	$1,026,593	$8,134,315	$1,090,778	$1,368,001	20%	**$2,323,937**
Northwest - Area	$155,891	$779,374	$73,108	$207,784	10%	**$121,616**

Table 99: Enhanced Permitting: Alternative 7 Total Costs

5.7. Total Costs

This section exhibits compilations of all of the Costs for each of the six (6) Cost Categories. Note that costs for Alternatives 2 thru 9 are Incremental Cost Changes from the No Action Alternative (Alternative 1) and are not Total costs.

5.7.1. Total Costs – Haulage

As shown in Table 100, the one significant Incremental Cost Change in the Haulage cost category occurs in Alternative 2 in the Central Appalachian Surface mines. This cost change is due to Alternative 2 prohibiting excess spoil placement in perennial or intermittent streams which dictates that the excess spoil for the above mentioned mines be hauled to an off-site location which increases the Haulage costs. The other changes in the ICC are due to the inclusion of dozer costs for the "bottom-up" construction method mandated in Action Alternatives 3 thru 8.

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG	
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Alternative 1	$575,562,665	$67,855,667	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$138,045,877	$0	$0
Alternative 2 Incremental Cost	$70,830,048	$15,260,126	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 3 Incremental Cost	$6,333,911	$3,700,486	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 4 Incremental Cost	$6,333,911	$4,122,102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 5 Incremental Cost	$6,333,911	$4,122,102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$6,333,911	$4,122,102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 7 Incremental Cost	$6,333,911	$4,122,102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 8 Incremental Cost	$6,333,911	$4,122,102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 100: Total Costs – Haulage

5.7.2. Total Costs – Landforming

Landforming costs are based on the size (acreage) of the respective Model mine as shown in Table 101. See CAPP Surface, Colorado Plateau Surface, Gulf Coast and Northern Rocky Mountains and Great Plains for significant Incremental Cost Changes from the No Action Alternative (Alternative 1). Since the landforming cost is dependent on the disturbed acreage

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG RP)	
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Alternative 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 2 Incremental Cost	$1,305,837	$434,070	$239,499	$0	$0	$3,420,027	$0	$2,166,952	$1,248,507	$0	$0	$6,562,883	$581,256	$1,248,507	$0
Alternative 3 Incremental Cost	$1,305,837	$434,070	$239,499	$0	$0	$3,582,832	$0	$2,223,419	$1,248,507	$0	$0	$6,744,102	$581,256	$1,248,507	$0
Alternative 4 Incremental Cost	$1,473,966	$524,160	$239,499	$0	$0	$3,608,681	$0	$2,223,419	$1,248,507	$0	$0	$6,777,801	$581,256	$1,248,507	$0
Alternative 5 Incremental Cost	$1,473,966	$524,160	$239,499	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 7 Incremental Cost	$1,473,966	$524,160	$239,499	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 8 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 101: Total Costs – Landforming

5.7.3. Total Costs –Stream Restoration

Stream Restoration costs (Table 102) are mainly influenced by the inclusion/exclusion of the requirement for restoring the ephemeral streams impacted by the Model mines.

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG RP)	
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Alternative 1	$866,400	$181,200	$0	$0	$0	$3,943,093	$0	$3,783,300	$4,542,000	$0	$0	$4,232,368	$1,857,205	$4,542,000	$0
Alternative 2 Incremental Cost	$776,160	$84,600	$152,280	$0	$0	$3,328,345	$0	$1,134,380	$13,178,430	$0	$0	$3,715,773	$1,510,322	$13,178,430	$0
Alternative 3 Incremental Cost	$431,200	$47,000	$84,600	$0	$0	$1,874,725	$0	$630,211	$7,321,350	$0	$0	$2,097,750	$839,068	$7,321,350	$0
Alternative 4 Incremental Cost	$431,200	$47,000	$84,600	$0	$0	$1,643,928	$0	$630,211	$7,321,350	$0	$0	$1,796,866	$839,068	$7,321,350	$0
Alternative 5 Incremental Cost	$431,200	$47,000	$84,600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$431,200	$47,000	$84,600	$0	$0	$1,874,725	$0	$630,211	$7,321,350	$0	$0	$2,097,750	$839,068	$7,321,350	$0
Alternative 7 Incremental Cost	$776,160	$84,600	$152,280	$0	$0	$3,328,345	$0	$1,134,380	$13,178,430	$0	$0	$3,715,774	$1,510,322	$13,178,430	$0
Alternative 8 Incremental Cost	$431,200	$47,000	$84,600	$0	$0	$1,643,928	$0	$630,211	$7,321,350	$0	$0	$1,796,866	$839,068	$7,321,350	$0
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 102: Total Costs – Stream Restoration

5.7.4. Total Costs – Stream Enhancement

As shown in Table 103, one of the significant Incremental Cost Changes in the Stream Enhancement cost category occurs in Alternative 2 in the Central Appalachian Surface mines. This cost change is due to Alternative 2 prohibiting excess spoil placement in perennial or intermittent streams which in turn leads to zero (0) Stream Enhancement costs. The other Incremental Cost Change of note occurs in the Central Appalachian Contour Model mine which shows a reduction of Stream Enhancement costs in Alternatives 4 thru 7 due to the maximization of excess spoil being placed on the mining bench.

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG RP)	
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Alternative 1	$11,105,600	$6,105,600	$0	$1,003,200	$11,256,800	$0	$629,100	$0	$0	$723,300	$2,078,700	$0	$0	$0	$723,300
Alternative 2 Incremental Cost	-$11,105,600	-$6,105,600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 3 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 4 Incremental Cost	$0	-$3,232,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 5 Incremental Cost	$0	-$3,232,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$0	-$3,232,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 7 Incremental Cost	$0	-$3,232,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 8 Incremental Cost	$0	-$3,232,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 103: Total Costs – Stream Enhancement

5.7.5. Total Costs – Reforestation / PLMU

Most of the significant Incremental Costs Changes are due to the Topsoil Salvaging in all of the Model mines and the reforestation in the Appalachian Surface Model mines (Table 104).

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG RP)	
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Alternative 1	$1,376,583	$425,436	$233,276	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 2 Incremental Cost	$3,227,992	$1,042,416	$620,192	$55,481	$673,034	$9,336,787	$123,545	$5,804,106	$211,674	$0	$0	$11,367,432	$1,394,617	$211,674	$0
Alternative 3 Incremental Cost	$3,724,672	$1,351,797	$603,190	$54,543	$661,822	$9,317,602	$123,545	$5,717,413	$162,765	$0	$0	$11,347,264	$1,394,617	$162,765	$0
Alternative 4 Incremental Cost	$3,724,672	$1,313,041	$603,190	$54,543	$661,822	$9,303,755	$123,545	$5,785,202	$244,148	$0	$0	$11,329,211	$1,394,617	$244,148	$0
Alternative 5 Incremental Cost	$3,719,483	$1,311,855	$603,822	$54,543	$661,822	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$7,231	-$8,266	$632	$0	$0	$26,027	$0	$143,568	$141,710	$0	$0	$29,773	$0	$141,710	$0
Alternative 7 Incremental Cost	$3,721,956	$1,312,084	$604,328	$54,543	$661,822	$9,336,326	$123,545	$5,804,106	$211,674	$0	$0	$11,366,830	$1,394,617	$211,674	$0
Alternative 8 Incremental Cost	$3,719,483	$1,311,855	$603,822	$54,543	$661,822	$9,321,789	$123,545	$5,725,405	$141,710	$0	$0	$11,350,650	$1,394,617	$141,710	$0
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 104: Total Costs – Reforestation /PLMU

5.7.6. *Total Cost – Enhanced Permitting*

Most of the Enhanced Permitting costs are based on the size (acreage) of the respective Model mine as shown in the table below. See CAPP Surface, Colorado Plateau Surface and Northern Rocky Mountains and Great Plains for significant Incremental Cost Changes from the No Action Alternative (Alternative 1).

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG RP)	
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Alternative 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 2 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 3 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 4 Incremental Cost	$3,091,699	$1,118,778	$484,466	$0	$0	$3,495,538	$0	$505,466	$157,001	$0	$0	$2,323,937	$121,616	$0	$0
Alternative 5 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 7 Incremental Cost	$3,091,699	$1,118,778	$484,466	$0	$0	$3,495,538	$0	$505,466	$157,001	$0	$0	$2,323,937	$121,616	$157,001	$0
Alternative 8 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 105: Total Costs – Enhanced Permitting

5.7.7. *Total Overall ICC Costs*

Shown below in (Table 106, Table 107) is a compilation of all of the additional costs (Incremental Cost Change) that are realized with the execution of the Action Alternatives (Alternatives 2 thru 9). These additional costs are outlined in the previous sections as Haulage, Landforming, Stream Restoration, Stream Enhancement, Reforestation and Enhanced Permitting. Shown below is an analysis of the major drivers of the Incremental Cost Change for each of the Action Alternatives.

- Alternative 2
  - Appalachia
    - The prohibition of valley fills substantially increased the Haulage Costs, but also decreased the Stream Enhancement costs due a decrease in the stream impacts.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost section.
  - Non-Appalachia

    - The introduction of the requirement for Stream Restoration of ephemeral streams.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost section.
- Alternative 3
  - Appalachia
    - Prohibition of durable rock fills and the requirement for "bottom-up" construction of valley fills.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost Section.
  - Non-Appalachia
    - The introduction of the requirement for Stream Restoration of ephemeral streams.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost section.
- Alternative 4
  - Appalachia
    - Prohibition of durable rock fills and the requirement for "bottom-up" construction of valley fills.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost Section.
    - Introduction of Enhanced Permitting practices
  - Non-Appalachia
    - The introduction of the requirement for Stream Restoration of ephemeral streams.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost section.
    - Introduction of Enhanced Permitting practices
- Alternative 5
  - Appalachia
    - Prohibition of durable rock fills and the requirement for "bottom-up" construction of valley fills.
    - The introduction of the requirement for Landforming
    - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost Section.
  - Non-Appalachia – This Alternative does not apply to Non-Appalachian Model Mines
- Alternative 6
  - Appalachia

        - Prohibition of durable rock fills and the requirement for “bottom-up” construction of valley fills.
    - Non-Appalachia
        - The introduction of the requirement for Stream Restoration of ephemeral streams.
- Alternative 7
    - Appalachia
        - Prohibition of durable rock fills and the requirement for “bottom-up” construction of valley fills.
        - The introduction of the requirement for Landforming
        - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost Section.
        - Introduction of Enhanced Permitting practices
    - Non-Appalachia
        - The introduction of the requirement for Stream Restoration of ephemeral streams.
        - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost section.
        - Introduction of Enhanced Permitting practices
- Alternative 8
    - Appalachia
        - Prohibition of durable rock fills and the requirement for “bottom-up” construction of valley fills.
        - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost Section.
        - Changes in the Riparian Zone to 100 foot and the addition of the Ephemeral streams into the Riparian Zone reforestation acreage.
    - Non-Appalachia
        - The introduction of the requirement for Stream Restoration of ephemeral streams.
        - The introduction of the requirement for Topsoil Salvage within the Reforestation Cost section.
- Alternative 9 - Alternative 9 mirrors the Baseline (Alternative 1) and therefore there are no ICC.

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area
Alternative 1	$588,911,248	$74,567,903	$233,276	$1,003,200	$11,256,800	$3,943,093	$629,100	$3,783,300	$4,542,000	$723,300	$2,078,700	$4,232,368
Alternative 2 Incremental Cost	$65,034,437	$10,715,612	$1,011,971	$55,481	$673,034	$16,085,159	$123,545	$9,105,438	$14,638,611	$0	$0	$21,646,088
Alternative 3 Incremental Cost	$11,795,620	$5,533,353	$927,289	$54,543	$661,822	$14,775,159	$123,545	$8,571,043	$8,732,622	$0	$0	$20,189,116
Alternative 4 Incremental Cost	$15,055,448	$3,893,081	$1,411,754	$54,543	$661,822	$18,051,902	$123,545	$9,144,298	$8,971,006	$0	$0	$22,227,816
Alternative 5 Incremental Cost	$11,958,560	$2,773,117	$927,921	$54,543	$661,822	$0	$0	$0	$0	$0	$0	$0
Alternative 6 Incremental Cost	$6,772,342	$928,836	$85,232	$0	$0	$1,900,752	$0	$773,779	$7,463,060	$0	$0	$2,127,524
Alternative 7 Incremental Cost	$15,397,692	$3,929,724	$1,480,572	$54,543	$661,822	$16,160,209	$123,545	$7,443,952	$13,547,105	$0	$0	$17,406,541
Alternative 8 Incremental Cost	$10,484,594	$2,248,957	$688,422	$54,543	$661,822	$10,965,717	$123,545	$6,355,616	$7,463,060	$0	$0	$13,147,516
Alternative 9 Incremental Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table 106: Total Overall ICC Costs

Alternative	Appalachia					Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest
	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area
Life of Mine Recoverable Coal Tonnage	37,000,000	5,000,000	1,600,000	3,000,000	69,300,000	92,200,000	20,500,000	40,700,000	12,400,000	19,100,000	106,000,000	1,056,200,000	37,000,000
Alternative 2 Incremental Cost per Ton	$1.76	$2.14	$0.63	$0.02	$0.01	$0.17	$0.01	$0.22	$1.18	$0.00	$0.00	$0.02	$0.09
Alternative 3 Incremental Cost per Ton	$0.32	$1.11	$0.58	$0.02	$0.01	$0.16	$0.01	$0.21	$0.70	$0.00	$0.00	$0.02	$0.08
Alternative 4 Incremental Cost per Ton	$0.41	$0.78	$0.88	$0.02	$0.01	$0.20	$0.01	$0.22	$0.72	$0.00	$0.00	$0.02	$0.08
Alternative 5 Incremental Cost per Ton	$0.32	$0.55	$0.58	$0.02	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Alternative 6 Incremental Cost per Ton	$0.18	$0.19	$0.05	$0.00	$0.00	$0.02	$0.00	$0.02	$0.60	$0.00	$0.00	$0.00	$0.02
Alternative 7 Incremental Cost per Ton	$0.42	$0.79	$0.93	$0.02	$0.01	$0.18	$0.01	$0.18	$1.09	$0.00	$0.00	$0.02	$0.08
Alternative 8 Incremental Cost per Ton	$0.28	$0.45	$0.43	$0.02	$0.01	$0.12	$0.01	$0.16	$0.60	$0.00	$0.00	$0.01	$0.06
Alternative 9 Incremental Cost per Ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 107: Total Overall ICC Costs per Ton of Recoverable Coal

6. ATTACHMENT A: SENSITIVITY ANALYSES

6.1. Haulage Costs

We have looked at 2 cost factors to investigate the sensitivity of the Haulage Incremental Cost Changes (ICC) to Alternative 1.The first is the Hourly Equipment Costs for the equipment utilized in the Haulage function. The second is the percentage of the overburden that is handled by each type of equipment (Truck or Bulldozer).

6.1.1. Hourly Equipment Costs

The original hourly equipment costs as shown in the Master Cost spreadsheets (shown below) were increased by 20 % and the Haulage costs were recalculated for Alt. 1, Alt. 2 and Alternatives 3 thru 8. Analysis was done for both the Truck cost and the Bulldozer costs individually.

Cost Criteria	CAPP Area Mine		CAPP Contour Mine	
	Truck	Bulldozer	Truck	Bulldozer
Original Cost per hour	591	244	353	244
Additional 20% Cost per hour	709	293	424	293

Table 109: Sensitivity of Hourly Equipment Costs in CAPP

6.1.2. Spoil Handling

The Spoil Handling percentage of overburden moved by each respective equipment group (truck or bulldozer) was changed in both the CAPP Area and CAPP Contour model mines. The cost per hour of the equipment was not changed. Shown below are the original percentages of overburden moved by equipment group:

Cost Criteria	CAPP Area Mine		CAPP Contour Mine	
	Truck	Bulldozer	Truck	Bulldozer
Original Percentage of Overburden moved	80	20	70	30

Table 110: Percentage of Overburden Moved in CAPP

6.1.3. Conclusions

Shown below are tables illustrating the comparisons for the 2 cost factors:

Scenario	CAPP Area Mine - Haulage Cost Sensitivity Analysis							
	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6	Alt. 7	Alt. 8
Current Overall Cost	$588,900,000	$653,900,000	$600,700,000	$604,000,000	$600,900,000	$595,700,000	$604,300,000	$599,400,000
Current Overall Cost Per Ton	$15.92	$17.67	$16.24	$16.32	$16.24	$16.10	$16.33	$16.20
% Difference from Alt. 1		11.0%	2.0%	2.6%	2.0%	1.2%	2.6%	1.8%
Overall Cost with 20% Increase in Truck Costs	$704,000,000	$783,200,000	$717,100,000	$720,300,000	$717,200,000	$712,100,000	$720,700,000	$715,800,000
Cost per Ton	$19.03	$21.17	$19.38	$19.47	$19.38	$19.25	$19.48	$19.35
% Difference from Alt. 1		11.3%	1.9%	2.3%	1.9%	1.2%	2.4%	1.7%
Overall Cost with 20% Increase in Dozer Costs	$605,900,000	$670,900,000	$619,000,000	$622,200,000	$619,100,000	$613,900,000	$622,600,000	$617,700,000
Cost per Ton	$16.38	$18.13	$16.73	$16.82	$16.73	$16.59	$16.83	$16.69
% Difference from Alt. 1		10.7%	2.2%	2.7%	2.2%	1.3%	2.8%	1.9%
Overall Cost with Truck Haulage at 70%	$570,300,000	$626,300,000	$582,100,000	$585,300,000	$582,200,000	$577,100,000	$585,700,000	$580,800,000
Cost per Ton	$15.41	$16.93	$15.73	$15.82	$15.74	$15.60	$15.83	$15.70
% Difference from Alt. 1		9.8%	2.1%	2.6%	2.1%	1.2%	2.7%	1.8%
Overall Cost with Truck Haulage at 90%	$606,800,000	$680,500,000	$618,600,000	$621,900,000	$618,800,000	$613,600,000	$622,200,000	$617,300,000
Cost per Ton	$16.40	$18.39	$16.72	$16.81	$16.72	$16.58	$16.82	$16.68
% Difference from Alt. 1		12.1%	1.9%	2.5%	2.0%	1.1%	2.5%	1.7%

Scenario	CAPP Contour Mine - Haulage Cost Sensitivity Analysis							
	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6	Alt. 7	Alt. 8
Current overall Cost	$74,600,000	$85,300,000	$80,100,000	$78,500,000	$77,300,000	$75,500,000	$78,500,000	$76,800,000
Current Overall Cost per ton	$14.92	$17.06	$16.02	$15.70	$15.46	$15.10	$15.70	$15.36
% Difference from Alt. 1		14.3%	7.4%	5.2%	3.6%	1.2%	5.2%	2.9%
Overall Cost with 20% Increase in Truck Costs	$85,200,000	$99,000,000	$90,700,000	$89,600,000	$88,500,000	$86,600,000	$89,600,000	$88,000,000
Overall Cost per ton	$17.04	$19.80	$18.14	$17.92	$17.70	$17.32	$17.92	$17.60
% Difference from Alt. 1		16.2%	6.5%	5.2%	3.9%	1.6%	5.2%	3.3%
Overall Cost with 20% Increase in Dozer Costs	$77,500,000	$88,200,000	$83,800,000	$81,700,000	$80,600,000	$78,800,000	$81,800,000	$80,100,000
Overall Cost per ton	$15.50	$17.64	$16.76	$16.34	$16.12	$15.76	$16.36	$16.02
% Difference from Alt. 1		13.8%	8.1%	5.4%	4.0%	1.7%	5.5%	3.4%
Overall Cost with Truck Haulage at 80%	$77,400,000	$90,400,000	$82,900,000	$78,800,000	$77,700,000	$75,800,000	$78,800,000	$77,200,000
Overall Cost per ton	$15.48	$18.08	$16.58	$15.76	$15.54	$15.16	$15.76	$15.44
% Difference from Alt. 1		16.8%	7.1%	1.8%	0.4%	-2.1%	1.8%	-0.3%
Overall Cost with Truck Haulage at 60%	$71,900,000	$80,400,000	$77,400,000	$73,300,000	$72,100,000	$70,300,000	$73,300,000	$71,600,000
Overall Cost per ton	$14.38	$16.08	$15.48	$14.66	$14.42	$14.06	$14.66	$14.32
% Difference from Alt. 1		11.8%	7.6%	1.9%	0.3%	-2.2%	1.9%	-0.4%

Table 111: CAPP Area Mine – Haulage Cost Sensitivity Analysis

A) Change in Equipment Costs
   a. CAPP Area Model Mine: The 20% cost increase to the Truck cost component of the Haulage cost added approximately $3.15 per ton to the overall cost in all of the Alternatives. The 20% cost increase to the Dozer cost component of the Haulage cost added approximately $0.50 per ton to the overall cost in all of the Alternatives. The percentage change in the Overall costs for Alternatives 2 thru 9 when compared to Alternative 1 (for both the Truck and Dozer cost increases) were consistent with the Current overall cost percentage changes.
   b. CAPP Contour Model Mine: The 20% cost increase to the Truck cost component of the Haulage cost added an average of approximately $3.25 per ton to the overall cost in all of the Alternatives. The 20% cost increase to the Dozer cost component of the Haulage cost added an average of approximately $0.65 per ton to the overall cost in all of the

Alternatives. The percentage change in the Overall costs for Alternatives 2 thru 9 when compared to Alternative 1 (for both the Truck and Dozer cost increases) were consistent with the Current overall cost percentage changes.

B) Change in Spoil Haulage Percentage

a. CAPP Area Model Mine: The change from 80% Truck haulage to 70% decreased the average overall cost per ton approximately $0.45 in all of the Alternatives. The change from 80% Truck haulage to 90% increased the average overall cost per ton by approximately $0.50 in all of the Alternatives. . The percentage change in the Overall costs for Alternatives 2 thru 9 when compared to Alternative 1 (for both percentage changes in the Truck haulage) were consistent with the Current overall cost percentage changes.

b. CAPP Contour Model Mine: The change from 70% Truck haulage to 60% decreased the average overall cost per ton approximately $0.90 in all of the Alternatives. The change from 70% Truck haulage to 80% increased the average overall cost per ton by approximately $0.30 in all of the Alternatives. . The percentage change in the Overall costs for Alternatives 2 and 3 when compared to Alternative 1 (for both percentage changes in the Truck haulage) were consistent with the Current overall cost percentage changes. Alternatives 4 thru 8 showed increased changes in comparison to the Current overall cost percentage changes.

In conclusion, the Equipment Cost and Spoil Handling changes described above created material changes in the Overall Cost per ton for both of the CAPP model mines (including Alternatives 1 thru 8). These ranged from a savings of $0.90 per ton to an additional cost of $3.25 per ton. When comparing the Action Alternatives (2 thru 8) with Alternative 1, the relative changes due to the Equipment Cost and Spoil Handling changes were very similar in all of the Alternatives.

6.2. Per Acre Costs for Reforestation of Riparian Zones

6.2.1. Background

The costs for Reforestation of the Riparian Zone are a very small percentage of the Overall costs, as shown by the table below. Because of the small cost, a sensitivity analysis of Reforestation of the Riparian Zone costs seems fruitless. Even at double or triple the cost, the effect on the Overall costs is insignificant.

Alternative 8															
Appalachia						Colorado Plateau		Gulf Coast	Illinois Basin			Northern Rocky Mountain	Northwest	Western Interior (same as ILLB Sur and UG RP)	
Surface - CAPP Area	Surface - CAPP Area	CAPP - Contour	Surface - NAPP Contour	UG - CAPP R&P	UG - NAPP LW	Surface - Area	UG - LW	Surface - Area	Surface - Area	UG - R&P	UG - LW	Surface - Area	Surface - Area	Surface - Area	UG - R&P
Total Overall Costs	$599,395,842	$76,816,860	$921,698	$1,057,743	$11,918,622	$14,908,810	$752,645	$10,138,916	$12,005,060	$723,300	$2,078,700	$17,379,884	$142,136,767	$12,005,060	$723,300
Reforestation of Riparian Areas	$13,557	$1,917	$1,186			$26,027		$143,568	$141,710			$29,773		$141,710	
% of Total Overall cost	0.00%	0.00%	0.13%	0.00%	0.00%	0.17%	0.00%	1.42%	1.18%	NA	NA	0.17%	0.00%	1.18%	NA

Table 112: Per Acre Costs for Reforestation of Riparian Zones Under Alternative 8

6.3. Production Levels and Stripping Ratio

6.3.1. Production Levels

Increasing or decreasing the production levels of the equipment has been partially evaluated by the Cost Change sensitivity analysis in Section 6.1 above. Changing the production levels of the equipment would inversely change the cost per cubic yard of moving the overburden which covers the coal (increase production-lower costs, decrease production-increase costs). As shown in Section 6.1, decreasing production and increasing costs causes a material change in the overall cost per ton in the CAPP surface model mines, but the relative percentage change in comparison to Alternative 1 was relatively minor.

6.3.2. Stripping Ratio

In order to evaluate the Stripping Ratio without changing the mine design, the thickness of coal for each model mine could be altered (decrease coal thickness-increase strip ratio, increase coal thickness-decrease strip ratio). The coal thickness changes would increase or decrease the life of mine coal tonnage. Using the Model Mine scenario, none of the other incremental costs would change if only the coal thickness changes. Shown below is a chart that illustrates the Overall cost per ton for several strip ratio scenarios for the CAPP Area Mine. Notice that the relationship between the Action Alternatives (Alt. 2 thru 8) and Alternative 1 remains the same no matter what the Strip ratio is.

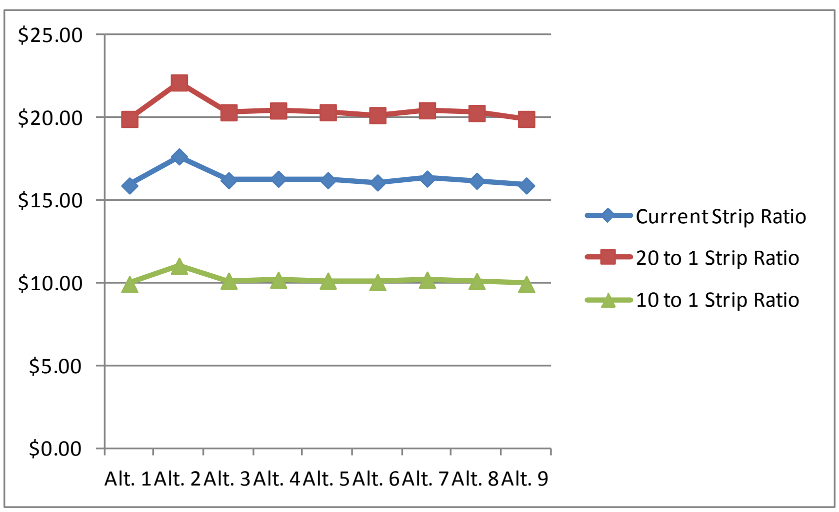

Figure 11: Alternative Stripping Ratios

Appendix D: Analysis of Potential Impacts to Underground Mining Operations

Prepared by:

Morgan Worldwide Consultants, Inc.

In Conjunction with:

Industrial Economics

August 14, 2014

TABLE OF CONTENTS

List of Figures

List of Tables

Abbreviated Glossary

Hydrologic Balance –the relationship between the quality and quantity of water inflow to, water outflow from, and water storage in a hydrologic unit such as a drainage basin, aquifer, soil zone, lake, or reservoir. It encompasses the dynamic relationships among precipitation, runoff, evaporation, and changes in ground and surface water storage (30 CFR 701.5).

Longwall Mining **-** a form of underground coal mining where a long panel of coal is extracted using a large shearer and the roof of the mined panel is allowed to collapse.

MDHB **-** an acronym that stands for: "material damage to the hydrologic balance outside the permit area". This acronym is used only in the context of this report.

Overburden **-** soil and rock material overlying a coal seam.

Overburden Depth **-** the vertical distance measured from the top of the coal seam to the ground surface.

Permanent Stream Loss **-** an unrecoverable diminution of stream flow, attributable to subsidence from underground mining, which permanently impacts the function of a stream. This definition is only used in the context of this report.

Pittsburgh Seam **-** a major coal seam extending into Ohio, Pennsylvania, and West Virginia that is primarily mined using the longwall mining method.

Stream Loss – loss of normal water flow in a stream that is attributable to the effects of subsidence from underground mining. This definition is only used in the context of this report.

Subsidence **-** the sinking of an area of land, which can occur as a result of the extraction of coal by underground mining methods.

Threshold Overburden Depth **-** the minimum overburden depth above which subsidence generally has low potential to cause permanent stream loss. This definition is only used in the context of this report.

1. EXECUTIVE SUMMARY

The Surface Mining Reclamation and Control Act (SMCRA) states that in order to receive a permit, an operator must demonstrate that “the proposed operation thereof has been designed to prevent material damage to hydrologic balance outside permit area.” (30 U.S.C., 510 (b)(3)). However, existing coal mining regulations do not define “material damage to the hydrologic balance outside the permit area.” The purpose of this report is to determine whether the addition of a national definition of “material damage to the hydrologic balance[1] outside the permit area,” (MDHB) will impact the recovery of underground mineable coal in the United States. For this analysis, material damage to the hydrologic balance is restricted to "permanent stream loss", which is defined as an unrecoverable diminution of stream flow, attributable to subsidence from underground mining, which may impact the function of a stream. The term, “material damage to the hydrologic balance outside the permit area,” in the context of this report, relates exclusively to impacts to the hydrologic balance while excluding other potential impacts caused by underground mining identified at 30 CFR 701.5 and in the context of 30 CFR 784.20 and 817.121.

The two primary methods of underground coal extraction are *room and pillar* and *longwall* mining. Generally, plans for room and pillar mines are more flexible because they can be readily modified to increase pillar sizes and adjust orientation beneath streams or other surface structures to avoid or minimize impacts caused by subsidence. Furthermore, subsidence events resulting from room and pillar mining can be sporadic and may not occur until decades after mining is completed due to the structural deterioration of coal pillars.[2] For these reasons, this analysis focuses on longwall mining operations.

<u>Based on the analyses and evaluations included in this report, MDHB should not occur in areas that meet the overburden threshold depth criteria specified for each coal region, and therefore, substantial coal resources will remain recoverable by the longwall mining method.</u>

Factors affecting possible stream loss from subsidence are varied and include mine height, mine configuration, extraction rate, overburden thickness, lithology, drainage area, previous mining, topography, and local and regional aquifer characteristics. Combined, these factors present a challenge for the evaluation of potential hydrologic impacts. The complexity of this evaluation requires substantial data for modeling local conditions and determining the likelihood and extent of subsidence induced impacts. As such, the potential for MDHB would be typically evaluated on a site-by-site basis.

To assess the potential impacts of a national MDHB definition this report examined longwall coal resources on a regional level. Because of the complexity of factors that influence the likelihood of MDHB, this assessment focused first on the overburden depth of coal seams by region. After isolating areas for which overburden depth could result in MBHD, a further review of regional lithology was also conducted as needed.

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[1] The "Hydrologic Balance" means the relationship between the quality and quantity of water inflow to, water outflow from, and water storage in a hydrologic unit such as a drainage *basin*, aquifer, soil zone, lake or reservoir. It encompasses the dynamic relationships among precipitation, runoff, evaporation, and changes in ground and surface water storage (30 CFR 701.5).

[2] Hill, D., "Coal Pillar Design Criteria for Surface Protection" in Aziz, N (ed), Coal 2005: Coal Operators' Conference, University of Wollongong & the Australasian Institute of Mining and Metallurgy, 2005, pp. 31-35.

Initially, an assessment of U.S. longwall production was made. Listed below are the active longwall mining regions and their 2012 longwall production numbers in thousand short tons (rounded)[3].

• Northern Appalachia	82,000
• Central Appalachia	12,000
• Southern Appalachia	12,000
• Illinois Basin	24,000
• Colorado Plateau	35,000
• Northern Rocky Mountains and Great Plains	18,000

Figure 1 below shows the location of coal regions in the United States, as well as the locations of potentially mineable coal. The Appalachian Basin is a combination of Northern, Central, and Southern Appalachian subregions.

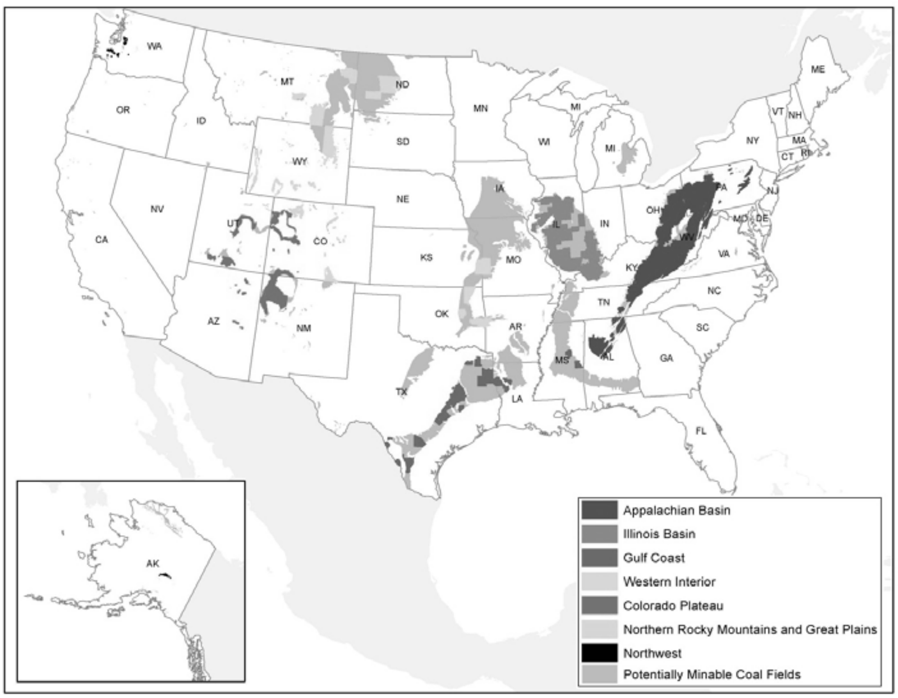

Figure 1: United States Coal Regions (Modified)

Coal regions were categorized as major or minor producers of longwall coal based on current coal production. At about 150 million tons produced in 2012, longwall production from the Northern Appalachia, Illinois Basin, and Colorado Plateau regions represent about 77 percent of the tons produced

[3] U.S. Energy Information Administration (EIA)

in the United States by this mining method[4]. Therefore, these three regions were categorized as major longwall producing regions and were given greater consideration in this report.

Minor longwall producing regions include Central Appalachia, Southern Appalachia, and Northern Rocky Mountains and Great Plains. Together these regions comprise only about 23 percent of the total U.S. longwall production[5]. Each of these minor regions was briefly examined.

After assessing various parameters, threshold overburden depth was adopted for a regional analysis of Northern Appalachia, Illinois Basin, and the Colorado Plateau. Overburden threshold depth is the vertical distance measured from the top of the coal seam to the ground surface. For example, existing literature indicates that in Northern Appalachia, mines operating at an overburden depth of less than 400 feet generally have a greater risk of effects from subsidence on the hydrologic balance[6]. Therefore, for Northern Appalachia, 400 feet was selected as the threshold overburden depth below which MDHB may occur.

In addition to overburden depth, another controlling factor of subsidence effects involves the geologic composition of the overburden. Where rock that can plastically deform during subsidence, such as fine-grained siliciclastic rocks, such as claystone, and certain shale strata, is present in a high percentage of the overburden, streams are less susceptible to permanent stream flow impacts.[7]

The designated threshold overburden depths for the three major longwall producing regions are listed below.

- Northern Appalachia 400 feet
- Illinois Basin 200 feet
- Colorado Plateau 500 feet

For the Illinois Basin, all current mines are operating deeper than the 200-foot threshold depth and future longwall mines are not expected to operate at shallower overburden depths. Shale layers in the Illinois Basin tend to exhibit mechanical plasticity during subsidence events that allow them to sag over a caving zone with only minor fracturing. The plasticity of the shale typically prevents groundwater migration into lower stratum. The subsidence trough will normally recharge and restore groundwater to pre-mining levels. In one study in Saline County, Illinois, the surficial drift experienced only minor changes in

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[4] *Id.*

[5] U.S. Energy Information Administration (EIA)

[6] John A. Owsiany and Burt A. Waite, "The Response of a High Order Stream to Shallow Cover Longwall Mining in the Northern Appalachian Coalfield," In: Proceedings, 20th International Conference on Ground Control in Mining, pp.149-156;
Wade, Scott A., "Stream flow characterization over longwall coal mines in Pennsylvania, Ohio, and West Virginia", West Virginia University, 2008

[7] Wade, Scott A., "Stream Flow Characterization over Longwall Coal Mines in Pennsylvania, Ohio, and West Virginia", 2008.

hydraulic properties from subsidence and was readily recharged.[8] With groundwater levels unaffected or readily recovered, permanent stream loss (MDHB) does not appear to be a factor in this region.

For the Colorado Plateau, most current mines are operating deeper than the 500-foot threshold overburden depth and future mines are anticipated to mine at similar or greater depths. Therefore, permanent stream loss due to longwall mining does not appear to be a prominent issue in this region.

With almost 82 million tons mined in 2012, Northern Appalachia is the largest producer of longwall coal in the United States[9]. The principal longwall-minable coal seam in Northern Appalachia is the Pittsburgh Seam. For the Pittsburgh Seam, overburden depths in Northern Appalachia vary from less than 200 feet in Ohio to greater than 1000 feet in northern West Virginia. Due to the variation in overburden depths across the Pittsburgh coal bed and its vast size, a geospatial analysis was initiated to model the resources that lie above and below the 400-foot threshold overburden depth.

Based upon coal seam height data and using a minimum 4-foot seam height for longwall mineable resources, about 10.5 billion tons were estimated in the Pittsburgh seam.[10] Of this resource, approximately 8.7 billion tons, or 83 percent of the total longwall mineable resources in the Pittsburgh seam, are located where overburden thickness is greater than 400 feet and thus is assumed to be mineable by longwall methods without MBHD being a major concern. In general, where the Pittsburgh seam has less than 400 feet of overburden, it could still be mineable by room and pillar methods and in some cases longwall methods, depending on the results of a site-specific analysis.

In Southeastern Ohio, the overburden above the Pittsburgh seam thins and can be less than 200 feet in thickness. However, this same overburden appears to contain significant claystone and shale strata. Where overburden is dominated by claystone and shale, which typically have relatively high plasticity, longwall mines can potentially operate at less than the overburden threshold depth without causing permanent stream loss. Ideally, these beds should reside near the surface where groundwater can readily recover and continue feeding the streams. The Ohio longwall mines may not be as susceptible to permanent stream loss, compared with other areas in the Northern Appalachian Region, where a high percentage of strata with low plasticity characteristics (i.e. sandstone) are present in the overburden.

Factors other than overburden thickness, such as overburden lithology, drainage area of the stream, topography, rainfall, and others, can influence stream impacts and recovery, but could not be taken into account as part of this analysis. In addition, because this analysis could not determine the precise location of all streams in these areas or predict panel extent and orientation relative to the undermining of a stream for future operations, it is possible that areas with less than 400 feet of cover and were categorized as unmineable by the longwall method, may be located in an area where no jurisdictional streams exist, or where other factors would indicate that material damage to the hydrologic balance outside the permit area would not occur. The scope of this study does not allow for a precise assessment of any particular location, but it can only indicate broad areas where a greater concern for potential MDHB exists.

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[8] Booth, Colin J., Department of Geology, Northern Illinois University. "Hydrologeologic Impacts of Underground (Longwall) Mining in the Illinois Basin", 1992.
[9] U.S. Energy Information Administration (EIA)
[10] This calculation total does not assess whether this resource is economically mineable or would otherwise be unmineable due to legal, environmental, social, or other restrictions.

In conclusion, the analysis included in this report demonstrates that significant underground mineable reserves exist in areas where material damage to the hydrologic balance (permanent stream loss) outside the permit area would not be expected to occur.

2. Introduction and Approach

The U.S. Office of Surface Mining Reclamation and Enforcement (OSM) is revising its regulations implementing the Surface Mining Reclamation and Control Act (SMCRA). In what is known as the Stream Protection Rule[11], OSM proposed revisions to current regulations in eleven separate categories and is currently preparing a Regulatory Impact Analysis (RIA) and an Environmental Impact Statement (EIS) to assess potential effects of the preferred option and various alternatives.[12] The purpose of this document is to determine what effect the addition of a definition of "material damage to the hydrologic balance[13] outside the permit area," will have on the recovery of underground mineable coal. In the context of this report, the term "material damage to the hydrologic balance outside the permit area" relates exclusively to impacts to the hydrologic balance and not to any other impacts potentially caused by underground mining, such as structural damage to buildings or settling surface lands. To enhance readability, the abbreviation "MDHB" will occasionally be used interchangeably with "material damage to the hydrologic balance outside the permit area."

2.1 Proposed Rule Changes

In order to assess MDHB, the proposed definition of "material damage to the hydrologic balance outside the permit area" was reviewed. For alternatives 2, 3, and 4, OSM proposed to define "material damage to the hydrologic balance outside the permit area". The proposed definition is "any quantifiable adverse impact on the quality or quantity of surface or groundwater or on the biological condition of any perennial or intermittent stream that would preclude any designated use under the Clean Water Act or any existing or reasonably foreseeable designated use of surface or groundwater outside the permit area. The definition includes impacts from underground mining (subsidence)." (See EIS, Chapter 2) Therefore, for the purpose of this assessment, permanent stream loss due to subsidence is considered "material damage to the hydrologic balance outside the permit area. Thus, under this analysis all alternatives will have the same impacts since permanent stream loss would constitute MDHB under each. [14]

2.2 Organization of this Report

Listed below is the general layout of the remainder of this report.

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[11] Stream Protection Rule; Environmental Impact Statement, 75 FR 34667, 34667 (June 18, 2010) (Notice of Intent to prepare an environmental impact statement and amend 30 CFR Chapter VII).

[12] *Id.*

[13] The "Hydrologic Balance" is an accounting of the inflow to, outflow from, and storage in a hydrologic unit such as a drainage basin, aquifer, soil zone, lake or reservoir.

[14] Each state regulatory authority may interpret the requirement that no material damage occur to the hydrologic balance outside the permit area differently, however, it is outside the scope of this analysis to analyze differing interpretations of the material damage requirement between states.

Section 2 - Introduction. This section lays the framework for this study. The background, scope, study areas, and limitations are discussed and defined.

Section 3 - Minor Longwall Producing Regions. This section discusses longwall operations and conditions in Central Appalachia, Southern Appalachia, and Northern Rocky Mountains and Great Plains.

Section 4 - Illinois Basin. Longwall mining in the Illinois Basin is discussed along with the unique geology that exists in this region.

Section 5 - Colorado Plateau. The Colorado Plateau longwall mining is discussed, particularly the mining occurring in Utah.

Section 6 - Northern Appalachia. Longwall mining in Northern Appalachia is evaluated and discussed, with focus on the Pittsburgh Seam.

Section 7 - Conclusions.

2.3 Background

In order to assess the impacts of the proposed rule revisions, Morgan Worldwide Consultants, Inc. (MWC) conducted a model mine plan analysis in Appendix B of the EIS. As part of this analysis, thirteen model mines were designed that were representative of the sizes and types of mining in various coal-producing regions of the United States. Alternative regulatory scenarios were applied as part of the RIA and EIS to these mines to determine how changes in regulatory requirements would affect mine designs, the amount of coal recovered, and/or the environmental impacts and benefits of the operation.

In most cases, the results of each model mine could be extrapolated to a regional level to determine impacts and benefits of various components of the rule to the region as a whole. However, modeling material damage to the hydrologic balance outside the permit area requires additional assessment. As described in detail in Appendix B, the MDHB element could not be analyzed for surface mines since the mines are not designed to be in a confined physical location and any hydrologic characteristics outside the permit area were not included in the mine design. In addition, since information concerning water quality and biological condition are unavailable for the streams created for the model mines, MDHB due to these factors could not be assessed.

Thus, the only determinant of material damage to the hydrologic balance outside the permit area that could be assessed as part of the model mine analysis was a decline in the water quantity of streams above underground mining operations. [15] As such, material damage to the hydrologic balance outside the permit area was equated with permanent stream loss for the purposes of this analysis, and all other types of material damage to the hydrologic balance outside the permit area are beyond the scope of this study.

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[15] Although it is recognized that some states include the surface area above the underground mine workings, commonly known as the "shadow area," as part of the permit area, this analysis considers the area above the underground workings as subject to the MDHB requirement. As explained further in the preamble to the Stream Protection Rule, protection to the hydrologic balance and the prevention of material damage applies to areas above the underground workings, regardless of whether these areas are included in the permit area.

2.4 Scope of Study

The purpose of this study is to evaluate how the recovery of underground mineable coal will be affected by the application of MDHB outside its permit area. As stated above, stream loss is the only hydrologic impact from subsidence considered in this study. The scope of this study does not allow for a precise assessment of any particular location, but it can only indicate broad areas where a greater concern for potential MDHB exists. Although other adverse impacts can occur from subsidence, they are excluded from this analysis. See Section 2.5 concerning limitations of this study.

This report will evaluate only regions with longwall production. Those regions with the highest production levels from longwall mines will be emphasized. Since the scope of this report is regional in nature, it should not be used to evaluate the subsidence potential or quantify recoverable reserves at any specific location.

2.5 Limitations

As stated previously, the purpose of this study is to evaluate how the recovery of underground mineable coal will be affected by the application of MDHB outside its permit area. No technical analysis of subsidence and its possible effect on the hydrologic regime is included in this report. This report generally assesses the underground mineable resource for each region with the adaptation of stream protection requirements. The following items are limitations to this study.

a) High extraction room and pillar mining was not considered. The majority of the literature documenting permanent stream loss caused by underground mining operations concerns longwall mines.[16] Generally, room and pillar mines are more flexible because they can be designed to leave protective pillars in-place beneath streams or other surface structures to avoid or minimize impacts caused by subsidence. Furthermore, subsidence from room and pillar mining is unpredictable in many cases, or may occur decades after the completion of mining due to the structural deterioration of coal pillars.[17] For these reasons, room and pillar mining was not considered in this study. As a result, this analysis is focused on longwall mining operations and did not assess the effect of the MDHB alternatives on room and pillar operations.

b) As with room and pillar mining, extracting coal by use of a highwall miner was also not considered.

c) This study did not consider impacts to water quality or biological conditions that may occur from subsidence.

d) This assessment did not consider alterations to groundwater flow.

[16] University of Pittsburgh, "The Effects of Subsidence Resulting from Underground Bituminous Coal Mining on Surface Structures and Features and on Water Resources, 2003 to 2008." Prepared for the Pennsylvania Department of Environmental Protection. Pittsburgh, PA., 2011.

[17] Hill, D., "Coal Pillar Design Criteria for Surface Protection" in Aziz, N (ed), Coal 2005: Coal Operators' Conference, University of Wollongong & the Australasian Institute of Mining and Metallurgy, pp. 31-35, 2005.

e) Only a single longwall mine was considered. No effects from multi-seam mines or abandoned underground mines were considered.

f) Effects originating from surface activities were not considered.

g) Geologic anomalies such as faults, which may respond unpredictably to subsidence, were not considered. Geologic anomalies are generally localized, and therefore, not applicable to a regional study.

h) Possible long-term subsidence from collapsing chain pillars was not considered.

i) Resource related information presented in Section 6.6 of this document should be considered as macro-level approximations and are intended only for the use of this report. Coal resources may be unmineable due to technological, economic, environmental, legal, and other factors. These factors were not considered in this report. Refer to the U.S. Geologic Survey or other applicable sources for published resource estimates.

j) Water quality issues at underground mining operations could cause MDHB regardless of whether the operation results in subsidence. Individual longwall mining operations can result in material damage to the hydrologic balance outside the permit area where overburden depth is greater than 400 feet or could not result in MDHB where overburden depth is less than 400 feet, depending on site-specific variables

k) The analysis assumes that any mine area where the overburden depth is less than the threshold depth may result in material damage to the hydrologic balance outside the permit area.

2.6 Study Areas

The primary focus of this report is on high-producing longwall regions. Therefore, to help determine the study areas for this report, an assessment of longwall coal production in the United States was made. Included in this section are summaries of U.S. longwall production and brief assessments of each longwall producing region.

2.6.1 U.S. Coal Producing Regions

Prior to selecting the study areas, longwall coal production in each region was assessed. The Draft Environmental Impact Statement divides the coal mining areas of the United States into seven regions:

- Northern Rocky Mountains and Great Plains
- Appalachian Basin
- Colorado Plateau
- Illinois Basin
- Gulf Coast
- Western Interior
- Northwest Region (Alaska)

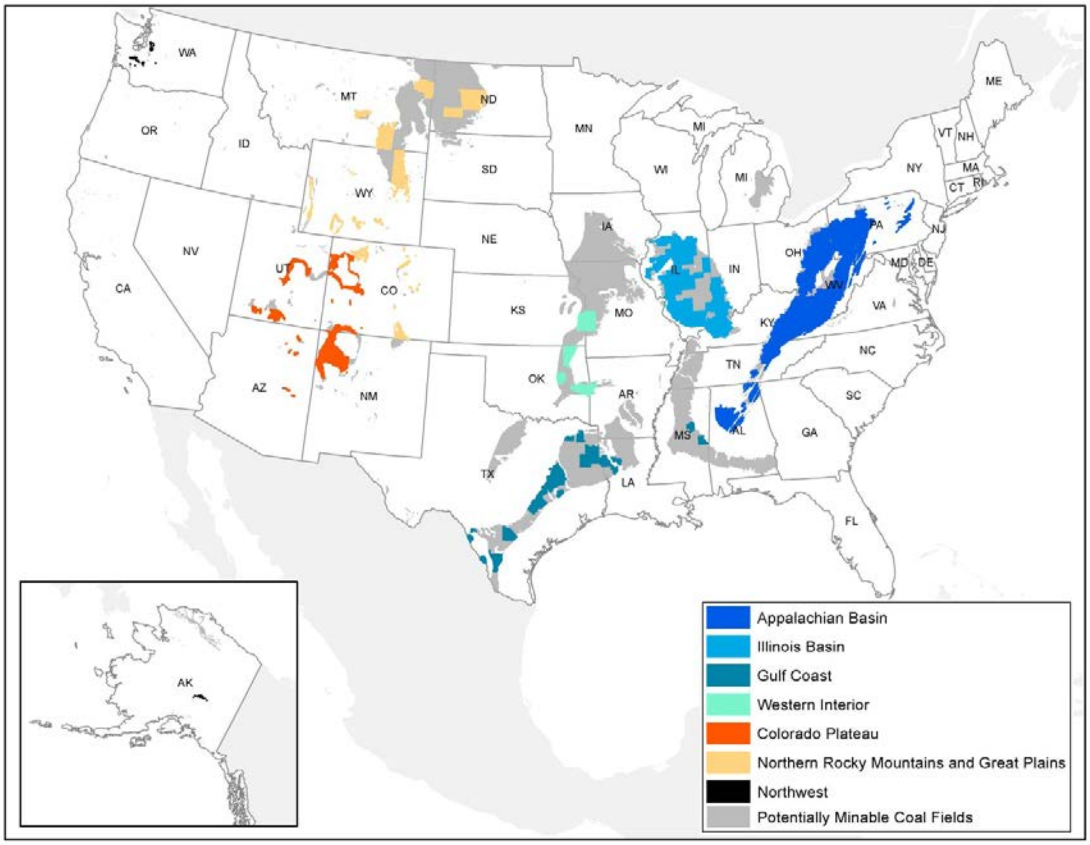

Figure 2: United States Coal Regions

Of these seven regions, longwall mining occurs in the Appalachian Basin, Colorado Plateau, the Illinois Basin, and the Northern Rocky Mountains and Great Plains. The Gulf Coast, Western Interior, and Northwest regions were not addressed since they contain no longwall mining. All tables in this section are from Energy Venture Analysis, Inc.

2.6.2 U.S. Longwall Mine Production

As a percentage of total U.S. underground coal production, longwall mining remained relatively constant, between 48% to 49%, from 2003 through 2011. In 2012, the percentage of longwall production increased by 4% to a total of 53%, becoming the principal method of underground coal extraction in the United States. As shown in Table 1, the total production of longwall mining in 2012 was about 183 million tons.

Tons (1000)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Underground	352,136	366,698	368,480	358,380	351,803	358,358	332,256	337,135	345,150	342,939
Surface	716,296	742,701	760,841	799,754	792,660	812,916	741,242	746,596	748,613	673,529
Total	1,068,432	1,109,399	1,129,321	1,158,134	1,144,463	1,171,274	1,073,498	1,083,731	1,093,763	1,016,468
Longwall Tons	168,618	177,836	178,874	172,897	170,133	172,677	161,406	165,664	168,886	182,880
Longwall % of UG	48%	48%	49%	48%	48%	48%	49%	49%	49%	53%

Table 1: U.S. Coal Production

2.6.2.1 *Illinois Basin Coal Production*

Total coal production in the Illinois Basin (ILLB) has increased from a low of about 89 million tons in 2003 to over 125 million tons in 2012. Longwall mining in the Illinois Basin lies exclusively within the state of Illinois. As seen in Table 3, six longwall mines are currently operating in the Illinois Basin for a total production of about 24 million tons in 2012. In Table 4, additional longwall sections or mines are expected to increase the total production to about 59 million tons per year within the next several years.

Tons (1000)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Illinois	31,760	32,370	32,139	32,729	32,855	33,074	34,014	33,377	37,828	48,703
Indiana	35,378	35,154	34,233	34,700	35,003	36,141	35,857	35,277	37,298	36,318
West Kentucky	21,505	23,409	26,437	27,287	28,267	30,134	32,976	36,896	40,989	42,043
TOTAL ILLB	88,643	90,780	92,781	94,376	94,955	97,970	101,460	104,165	114,463	125,187
IL Share of ILLB	36%	36%	35%	35%	35%	34%	34%	32%	33%	39%

Table 2: Illinois Basin Production by State

State	Company	Mine	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Illinois	Exxon	Monterey #1	3,008	3,051	3,008	2,767	2,134	0	0	0	0	0
Illinois	Foresight Energy	Hillsboro	0	0	0	0	0	0	0	21	491	2,365
Illinois	Foresight Energy	Sugar Camp A	0	0	0	0	0	0	0	324	856	4,690
Illinois	Foresight Energy	Mach #1	0	0	0	94	1,074	5,504	5,921	5,795	7,227	7,528
Illinois	Murray Energy	New Era	6,011	6,518	5,914	7,214	7,009	5,263	6,267	5,775	4,963	5,642
Illinois	Murray Energy	New Future Mine	0	0	0	0	0	0	0	617	1,783	3,642
TOTAL			9,020	9,568	8,921	10,075	10,217	10,767	12,188	12,532	15,320	23,868

Table 3: Illinois Basin Longwall Mines

Company	Complex	Full Production (1000 Tons)
Foresight	Akin	6,800
Foresight	Ewing	6,800
Foresight	Locus Grove	6,800
Foresight	Sugar Camp B	7,500
White Oak	White Oak	7,000
TOTAL		34,900

Table 4: Announced Illinois Basin Longwall Mines

2.6.2.2 *Northern Rocky Mountains and Great Plains Longwall Production*

Production from longwall mining in the Northern Rocky Mountains has steadily increased to over 18 million tons in 2012. Coal production in this region is constrained by less demand due to gas switching and a diminishing market from non-local power plants. Therefore, no significant increases in production are currently forecasted for this region.

State	Company	Mine	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WY	Pacificorp	Bridger Underground	0	43	410	519	2,822	3,501	3,472	3,819	3,043	4,637
MT	Signal Peak Energy	Bull Mountains	32	158	162	321	47	168	776	4,389	5,136	5,708
CO	Peabody	Foidel Creek	8,029	8,558	9,370	8,636	8,290	8,004	7,827	7,727	7,749	7,975
TOTAL			**8,061**	**8,759**	**9,942**	**9,476**	**11,159**	**11,674**	**12,074**	**15,935**	**15,928**	**18,319**

Table 5: Northern Rocky Mountains Longwall Mines

2.6.2.3 Colorado Plateau Longwall Production

Longwall mining in the Colorado Plateau has steadily decreased since 2007 from about 48 million tons to about 35 million in 2012. Production from the Colorado Plateau region has declined in conjunction with the diminishing low sulfur coal demands from non-local power plants.

State	Company	Mine	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
UT	Arch Coal	Dugout Canyon	2,941	3,811	4,592	4,387	3,826	4,145	3,291	2,461	2,395	1,516
UT	Arch Coal	Skyline	2,771	465	380	1,647	2,533	3,120	2,718	2,805	2,948	1,894
UT	Arch Coal	Sufco	7,126	7,568	7,569	7,908	6,712	6,946	6,748	6,398	6,498	5,650
UT	Murray Energy	Crandall Canyon	1,202	872	1,593	605	402	0	0	0	0	0
UT	Murray Energy	Lila Canyon	0	0	0	0	0	0	0	72	156	304
UT	Murray Energy	Aberdeen	444	1,989	1,548	2,089	1,045	242	0	0	0	0
UT	Murray Energy	West Ridge	2,974	2,265	2,627	3,022	4,255	3,809	3,063	3,326	3,566	2,409
UT	Pacificorp	Deer Creek	3,938	3,356	3,910	3,748	3,685	3,878	3,833	2,954	3,143	3,295
UT	Pacificorp	Trail Mountain	0	0	0	0	0	0	0	0	0	0
CO	Arch Coal	West Elk	6,491	6,493	5,577	6,012	6,874	6,506	4,475	4,794	5,896	6,852
CO	Bowie Resources	Bowie #2	4,943	4,096	1,852	4,420	5,481	2,862	1,213	1,333	2,235	3,430
CO	Bowie Resources	Bowie #3	0	600	2,219	0	0	0	0	0	0	0
CO	Oxbow Carbon	Elk Creek	4,596	6,551	6,545	5,128	4,824	4,903	5,703	3,794	3,008	2,958
CO	Oxbow Carbon	Sanborn Creek	494	0	0	0	0	0	0	0	0	0
CO	Deseret G & T	Deserado	2,043	2,551	2,149	1,713	1,424	2,067	2,214	1,723	1,984	1,673
CO	Peabody	Sage Creek	0	0	0	0	0	0	0	0	0	36
NM	BHP,etc.	San Juan	5,890	7,685	7,905	6,993	6,898	7,046	6,499	4,932	3,983	4,960
TOTAL			**45,854**	**48,302**	**48,467**	**47,671**	**47,960**	**45,524**	**39,758**	**34,592**	**35,812**	**34,979**

Table 6: Colorado Plateau Longwall Mines

2.6.2.4 Appalachian Basin Coal Production

The Appalachian Basin is divided into three coal regions: Northern Appalachia, Central Appalachia, and Southern Appalachia. States that make up these coal regions include Ohio, West Virginia, Maryland, Pennsylvania, Kentucky, Tennessee, and Alabama. The total 2012 longwall production for the Appalachian Basin was about 106 million tons, making it the leading longwall coal producing region in the United States. In the following three sections, a discussion of longwall coal production in each of these regions is presented.

2.6.2 .4.1 Northern Appalachia (NAPP)

Northern Appalachia consists of Pennsylvania, Ohio, and the northern West Virginia coalfield. In 2012 about 82 million tons were mined in Northern Appalachia, making it the most productive longwall mining region in the Appalachian Basin. See Table 7. Additionally, another 32 million tons from new operations are expected to increase production to over 100 million tons per year. See Table 8 and Table 9. Almost all of the longwall production in this region originates from the Pittsburgh coal seam.

Tons (1000)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Underground	98,378	106,875	110,952	107,070	106,699	105,886	100,270	103,627	105,715	104,134
Surface	25,924	26,467	27,393	27,251	25,282	29,320	25,964	25,496	25,542	20,654
TOTAL NAPP	124,302	133,343	138,345	134,321	131,981	135,206	126,233	129,123	131,257	124,788
Longwall Tons	75,566	82,660	88,734	84,746	84,177	82,062	78,520	79,984	81,097	81,746
Longwall % of UG	77%	77%	80%	79%	79%	78%	78%	77%	77%	79%
Longwall % of Total	61%	62%	64%	63%	64%	61%	62%	62%	62%	66%

Table 7: Northern Appalachia Production

State	Company	Mine	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
MD	Alliance Resource	Mettiki	3,252	3,146	2,739	2,316	0	0	0	0	0	0
OH	Murray Energy	Century	4,628	5,821	6,631	6,451	7,142	6,844	6,033	6,214	7,081	8,447
OH	Murray Energy	Powhatan #6	4,886	4,537	5,343	4,370	4,595	5,798	6,733	6,378	6,416	5,768
PA	Alpha	Cumberland	6,247	5,195	7,091	7,516	7,264	7,321	6,819	5,764	6,185	6,425
PA	Alpha	Emerald	6,620	5,768	6,344	5,922	5,674	6,343	5,559	4,902	3,713	4,384
PA	Consol Energy	Bailey	9,391	10,134	11,077	10,175	9,828	9,996	10,267	10,607	10,833	10,123
WV	Alliance Resource	Mettiki	0	0	115	561	2,786	2,561	2,215	2,449	2,318	2,285
WV	Arch Coal	Leer	0	0	0	0	0	0	0	0	10	56
PA	Consol Energy	Enlow Fork	9,889	10,219	9,774	10,703	11,222	11,089	11,093	9,942	10,190	9,459
PA	Consol Energy	Mine 84	3,963	3,964	3,830	3,505	3,606	1,838	514	0	0	0
PA	Murray Energy	Maple Creek	165	0	0	0	0	0	0	0	0	0
WV	Alliance Resource	Tunnel Ridge	0	0	0	0	0	0	0	175	275	2,001
WV	Consol Energy	Blacksville	5,450	5,719	5,259	5,040	5,150	5,584	3,769	4,508	4,342	3,231
WV	Consol Energy	Loveridge	304	4,971	6,359	6,383	6,642	5,193	6,004	5,869	5,639	5,869
WV	Consol Energy	McElroy	6,792	8,357	10,419	10,477	9,667	9,637	9,864	10,095	9,253	9,400
WV	Consol Energy	Robinson Run	5,739	6,246	6,148	5,740	6,502	5,627	5,545	5,500	5,958	4,992
WV	Consol Energy	Shoemaker	3,844	3,694	3,506	965	79	1,138	296	3,850	5,149	5,316
WV	Patriot Coal	Federal #2	4,397	4,890	4,100	4,622	4,020	3,093	3,810	3,732	3,745	4,045
TOTAL			**75,566**	**82,660**	**88,734**	**84,746**	**84,177**	**82,062**	**78,520**	**79,984**	**81,107**	**81,801**

Table 8: Northern Appalachia Longwall Mines (1000 tons)

State	Company	Complex	Full Production (1000 Tons)
PA	Alliance	Penn Ridge	5,000
PA	Alpha	Foundation	7,000
PA/WV	Consol	BMX	5,000
WV	Consol	Wolfpen Knob	8,500
WV	Arch	Leer #1	3,500
WV	Arch	Tygart #2	3,000
TOTAL			**32,000**

Table 9: Announced Northern Appalachia Longwall Mines)

2.6.2.4.2 Central Appalachia Coal Production (CAPP)

Central Appalachia consists of coalfields located in eastern Kentucky, southwest Virginia, northern Tennessee, and southern West Virginia. Coal production in Central Appalachia has declined signifiantly from its peak production in 2006 of about 236 million tons to about 147 million tons in 2012. However, the percent of longwall production has risen from a low of 7% in 2007 to its current high of 15% in 2012. Longwall production peaked at about 15 million tons in 2003 before stabilizing at about 12 million tons per year for the period from 2010 through 2012. See Table 10. Longwall production originates from one mine located in Virgina and four mines located in West Virgina. See Table 11.

Tons (1000)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Underground	130,160	127,191	122,881	117,659	109,233	114,733	97,594	95,788	93,488	77,527
Surface	100,505	105,015	112,491	118,516	116,408	118,714	97,062	88,459	89,234	69,156
TOTAL CAPP	**230,159**	**232,192**	**235,373**	**236,175**	**225,642**	**233,447**	**194,656**	**184,247**	**182,723**	**146,714**
Longwall Tons*	14,984	12,629	9,820	10,942	8,142	13,158	9,803	12,760	12,320	11,502
Longwall % of UG	**12%**	**10%**	**8%**	**9%**	**7%**	**11%**	**10%**	**13%**	**13%**	**15%**
Metallurgical Tons	77,689	77,036	75,361	72,821	70,992	76,702	64,155	70,370	69,996	62,943
Longwall % of Met	**19%**	**16%**	**13%**	**15%**	**11%**	**17%**	**15%**	**18%**	**18%**	**18%**

*** All longwall tons are from mines whose primary market is metallurgical.**

Table 10: Central Appalachia Production

ST	Company	Mine Complex	Mine	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WV	Alpha	Liberty	JUSTICE #1	1,820	870	734	933	685	1,002	612	423	365	753
WV	Arch Coal	Mountain Laurel	MOUNTAINEER II MINE	0	0	9	295	1,759	4,187	3,756	4,606	3,292	2,544
WV	Cliffs	Pinnacle	PINNACLE MINE	2,470	1,753	2,636	2,014	1,424	2,112	518	1,108	1,166	2,433
WV	Patriot Coal	Panther	American Eagle	4,128	4,095	3,468	2,405	1,457	2,325	2,072	1,940	1,843	2,266
VA	Consol Energy	Buchanan	BUCHANAN MINE #1	4,686	4,377	1,724	5,009	2,817	3,531	2,846	4,682	5,654	3,506
VA	Consol Energy	VP 8	VP 8	1,880	1,533	1,248	286	0	0	0	0	0	0

Table 11: Central Appalachia Longwall Mines (1000 tons)

2.6.2.4.3 Southern Appalachia Coal Production (SAPP)

Southern Appalachia consists of coalfields in southern Tennessee, northern Alabama, and northwestern Georgia. Coal production in Southern Appalachia has remained at about 20 million tons from 2003 through 2012 with longwall production consisting of more than half of the overall production. Longwall production peaked at about 15 million tons in 2003 and 2004 and is currently at about 12 million tons per year. See Table 12. For 2012, longwall production originated from five mines: Oak Grove mine, Shoal Creek mine, Blue Creek #4 mine, Blue Creek #7 mine, and the North River #1 mine. See Table 13.

Tons (1000)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Underground	15,351	16,114	13,295	10,737	11,462	12,281	11,505	12,513	10,879	12,570
Surface	4,762	6,232	8,003	8,285	8,180	8,288	7,330	7,759	8,192	6,709
TOTAL SAPP	20,113	22,397	21,427	19,215	19,962	21,139	19,160	20,638	19,381	19,412
Longwall Tons	15,134	15,918	13,102	10,548	11,264	12,053	11,277	12,311	10,728	12,410
Longwall % of UG	99%	99%	99%	98%	98%	98%	98%	98%	99%	99%
Metallurgical Tons	11,616	12,242	9,761	7,919	8,427	9,921	9,021	10,236	9,106	10,892
LW Met Tons	11,616	12,192	9,670	7,784	8,128	9,130	8,571	9,274	8,020	10,161
LW Met % of Met Tons	100%	100%	99%	98%	96%	92%	95%	91%	88%	93%

Table 12: Southern Appalachia Production

Company	Mine Complex	Mine	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Chevron Mining	North River	NORTH RIVER # 1	3,517	3,726	3,432	2,764	3,137	2,923	2,706	3,037	1,359	0
Cliffs	Oak Grove	OAK GROVE MINE	1,730	1,502	1,716	1,415	1,035	985	871	926	526	2,207
Drummond	Shoal Creek	SHOAL CREEK MINE	3,840	3,813	2,218	818	1,326	2,106	1,615	1,680	1,761	1,287
Walter Energy	Blue Creek #4	NO. 4 MINE	2,798	3,053	3,039	2,187	3,074	3,188	2,719	2,797	2,123	1,903
Walter Energy	Blue Creek #5	NO. 5 MINE	1,386	1,484	657	806	0	0	0	0	0	0
Walter Energy	Blue Creek #7	NO. 7 MINE	1,861	2,339	2,039	2,558	2,692	2,852	3,366	3,870	3,610	4,764
Walter Energy	North River	NORTH RIVER # 1	0	0	0	0	0	0	0	0	1,348	2,249

Table 13: Southern Appalachia Longwall Mines (1000 tons)

2.6.3 Summary

Longwall production is expected to increase in some regions or remain near 2012 production levels for the foreseeable future. Production in the Illinois Basin will reportedly increase by 35 million tons per year as new mines become active. Similarly, Northern Appalachia is expected to increase production by about 32 million tons per year. However, other regions will remain the same or possibly decrease production. Production levels in Central and Southern Appalachia should each remain at about 12 million tons per year. Also, the Northern Rocky Mountains and Colorado Plateau regions are expected to remain near the same production levels as in 2012. See Table 14 and Figure 3.

Three regions are expected to comprise about 77 percent of the projected longwall production in the U.S. for the foreseeable future. These regions are:

- Northern Appalachia

- Illinois Basin
- Colorado Plateau

For the purpose of this report, Northern Appalachia, Illinois Basin, and Colorado Plateau will be considered the ***major*** longwall producing regions in the U.S. Whereas Central Appalachia, Southern Appalachia, and Northern Rocky Mountains and Great Plains will be considered ***minor*** longwall producing regions.

Evaluations of the Illinois Basin and the Colorado Plateau regions are included in this report. For Northern Appalachia, a more detailed analysis of the Pittsburgh Seam has been conducted since it represents the principal coal seam in the highest longwall producing region in the United States. A section dedicated to the minor longwall producing regions, Central Appalachia, Southern Appalachia, and Northern Rocky Mountains and Great Plains, has also been included.

Region	2012 Longwall Production (thousand short tons)
Northern Appalachia	81,746
Central Appalachia	11,502
Southern Appalachia	12,410
Illinois Basin	23,868
Colorado Plateau	34,979
Northern Rocky Mtns	18,319
TOTAL	**182,824**

Table 14: 2012 Longwall Production

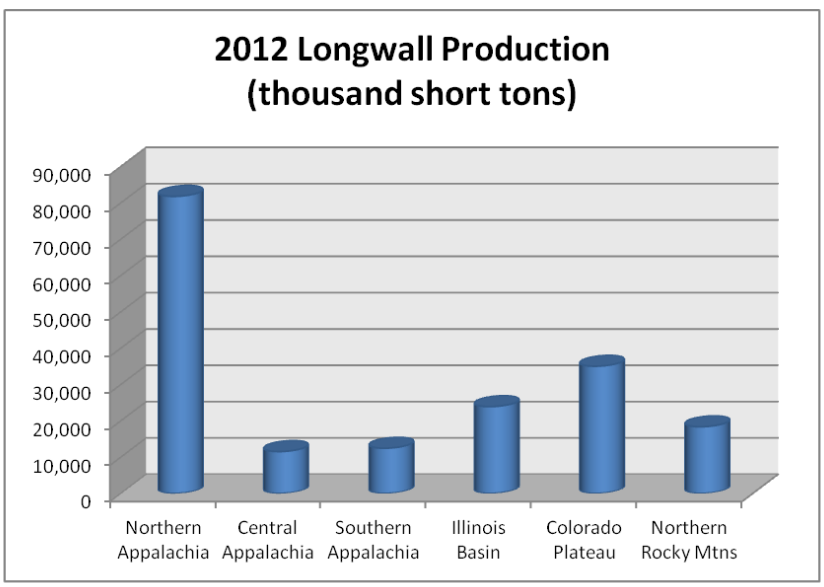

Figure 3: 2012 Longwall Production

Region	Projected Longwall Production (thousand short tons)
Northern Appalachia	106,746
Central Appalachia	11,502
Southern Appalachia	12,410
Illinois Basin	58,768
Colorado Plateau	34,979
Northern Rocky Mtns	18,319
TOTAL	**242,724**

Table 15: Projected Longwall Production

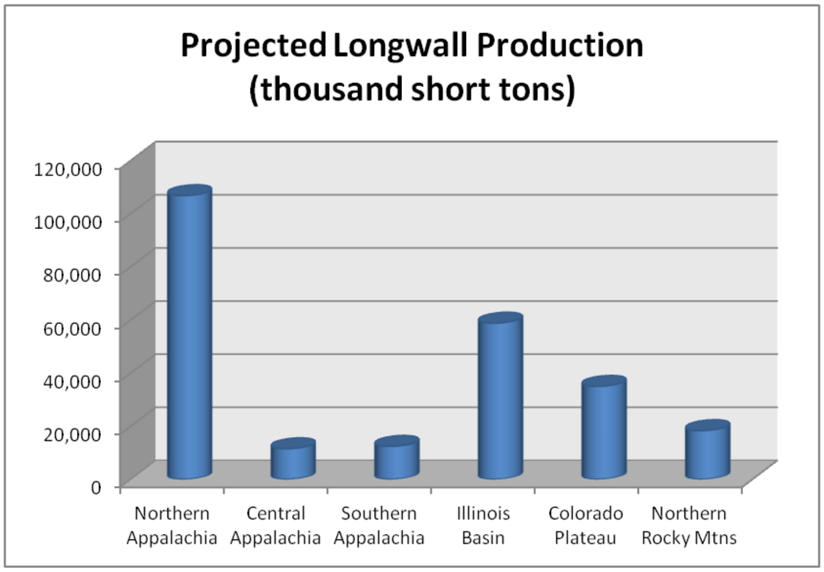

Figure 4: Projected Longwall Production

2.7 Literature Review

A literature review was conducted for this report to evaluate the available information concerning the effects of subsidence on stream loss. Factors influencing possible stream loss from subsidence are varied and include coal height, mine configuration, extraction rate, overburden thickness, lithology, drainage area, previous mining, topography, and local and regional aquifer characteristics.[18]

Because the scope of this report is regionally based, its analysis is restricted to factors that could be evaluated across large areas. Consequently, literature that focused on site specific factors was not included in this study.

[18] Energy Information Administration, U.S. Department of Energy, "Longwall Mining", 1995

Within the constraints of this broad-based perspective, the literature review indicates an inverse relationship exists between overburden depth and permanent stream loss (deeper overburden depth equals less permanent stream loss). Furthermore, the review suggests that each region has varying threshold overburden depths, which are reflective of their unique geologic conditions. Longwall mining could generally occur at depths greater than the threshold level without causing permanent stream loss, but longwall mining at depths shallower than the threshold level may require a detailed investigation, due to concerns with subsidence causing permanent stream loss.

Certain factors may cause the threshold depth to vary on a local or subregional level. For instance, tensile cracks attributed to longwall mining can be found in overburden greater than the threshold overburden depth where a high percentage of sandstone is present. However, where overburden is dominated by claystone and shale, longwall mines can potentially operate at shallower depths without causing permanent stream loss due to the plasticity of these beds.

In Illinois, where glacial drift consists of finer material with lower hydraulic conductivity, groundwater flow rates are lower. Since the water table in glacial till generally recovers after subsidence has occurred, permanent stream loss from longwall mining has not been a central issue in this region.

While conditions could allow for longwall mining in areas with more shallow overburden or result in permanent stream loss at deeper mines, this analysis focuses almost solely on the relationship between longwall mining and overburden depth. This approach allows for a broad-based regional analysis by identifying large areas where longwall mining presents an increased risk of permanent stream loss. It should be noted that this study does not identify or address high-risk areas where stream loss is probable.

In all cases the overburden depths of the previously designed model mines in Appendix B were deeper than the threshold levels. As a result, MDHB due to permanent stream loss was not predicted to occur at any of these conceptual mines. Thus, it was unclear from the model mine analysis the extent to which other current or future mines would be at risk of causing MDHB due to permanent stream loss and how those operations would be affected as a result. Extrapolating the results based on the model mines to a regional level could be misleading with the unintended implication that underground mines in any region would not cause material damage from permanent stream loss despite their overburden depths.

Since each region has different threshold overburden depths and could not be analyzed through the model mine analysis, the regions containing significant longwall mining are assessed in greater detail in this report.

2.8 Longwall Mining and Subsidence Impacts

Longwall mining involves the layout and extraction of large panels extending commonly 1000 feet or more wide by 10,000 feet, or more, long. During longwall mining, coal is mined from the panel, usually by means of a shearer with rotating cutters. Figure 5 represents a typical longwall mining section.

The cutting device is moved back and forth across the face, removing up to three feet of coal with each pass. The sheared coal is carried away from the face by an armored face conveyor and then transported out of the mine. A series of powered supports, lined up side-by-side across the longwall panel, provides roof support along the cutting face.

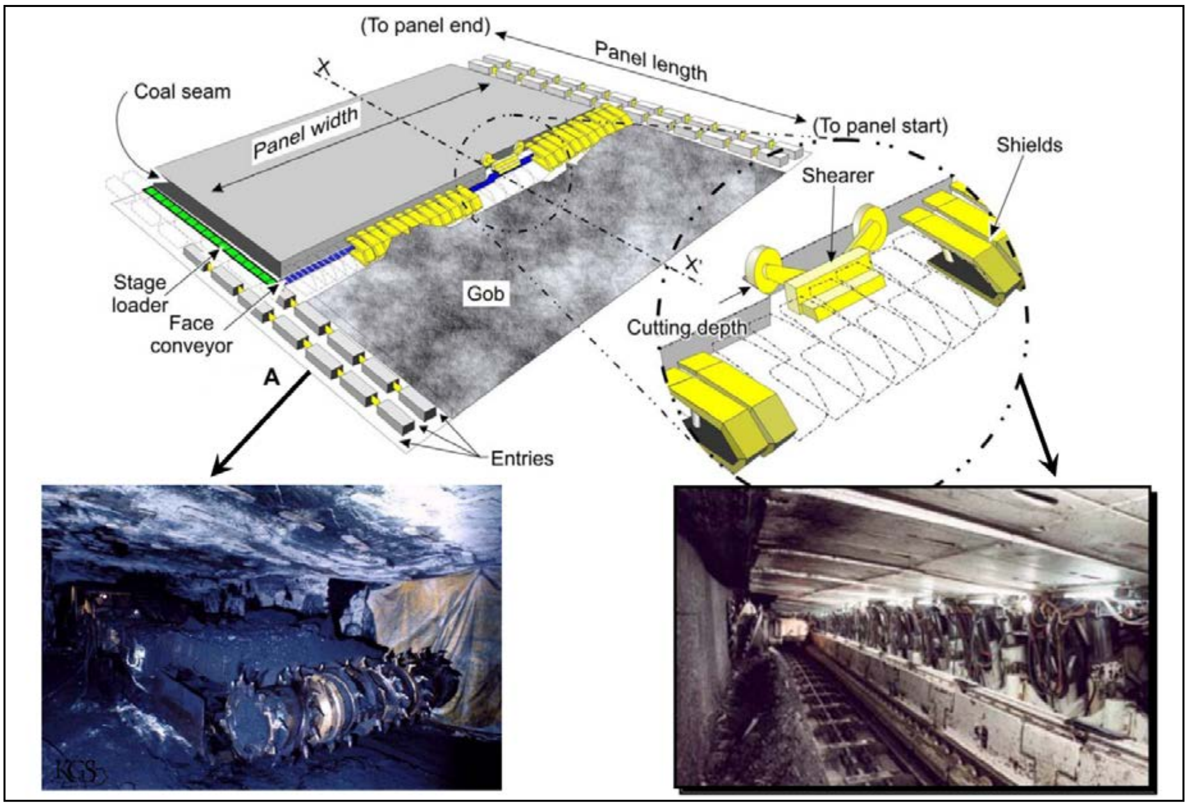

Figure 5: Schematics of a Longwall Mine[19]

Planned roof collapse is intrinsic to longwall mining and its effects may occur rapidly compared to room and pillar coal mining. Since coal is completely removed for panels up to 240 acres in size, roof collapse from longwall mining is inevitable.

Subsidence may occur when overlying strata collapses into voids created by mining, ultimately leading to deformation of the surface.[20] The degree of deformation depends upon several factors, including the

[19] Karacan, C.O. and Dougherty, H.N. "Evaluation and Production Models for Coal Mine Methane Control and Utilization", NIOSH Slide Presentation

amount of stress change, the amount of space over which the impact occurs, and the degree of rock support.[21] These factors, if sufficient, can cause the rock above the underground mine void to rubbelize and deform overlying strata.[22] Resulting ground movements can create bedrock fractures, which could affect the hydrologic regime and cause MDHB.

Several geological and mining factors affect whether substantive surface subsidence will occur. These factors include coal seam thickness, overburden depth, dip, the amount of material extracted, the width of the mined area, mining method, extraction rate, strength and make-up of the rock surrounding the mine void, stress state, the presence of geologic characteristics such as faults and folds, the nature of near

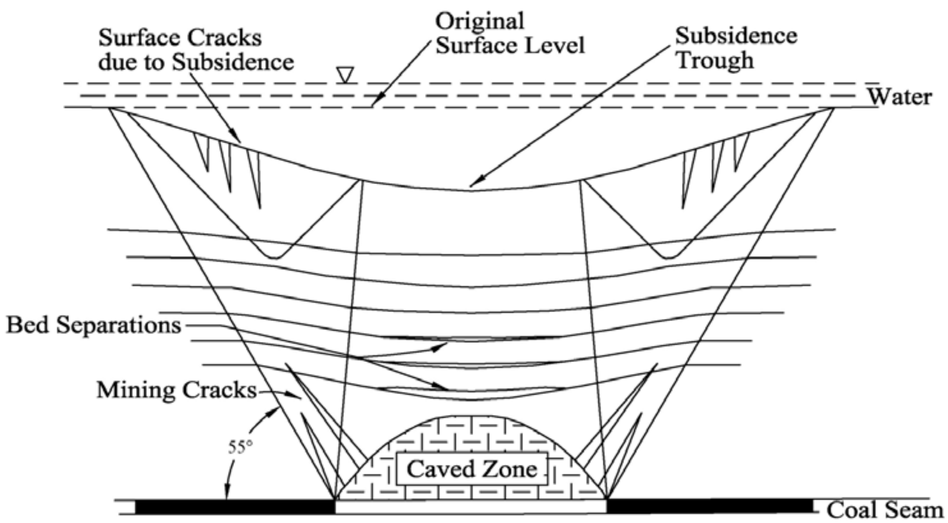

Figure 6: Diagram of Longwall Mining Subsidence (Diagram not to Scale)[23]

surface material, and hydrogeology.[24] With numerous variables influencing the nature of mine subsidence and its potential to cause permanent stream loss, a site specific analysis would provide the most accurate assessment of possible impacts for an individual underground mine.

The collapse of the rock can cause fractures in the overlying strata and subsidence of surface topography. For the purpose of illustration, Figure 6 is an exaggerated depiction of the effects of subsidence. Actual subsidence can displace the surface from amounts that are immeasurable to several feet.

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[20] Harrison, John P., “Mine Subsidence,” *SME Mining Engineering Handbook* 3rd Edition Volume 1 p.627, edited by Peter Darling, 2011.
[21] *Ibid.*
[22] *Ibid.*
[23] Kendorski, F.S., (Adapted from) “Effect of Full Extraction Underground Mining on Ground and Surface Waters A 25 Year Retrospective.” *Proceedings, 25th Intl. Conference on Ground Control in Mining*. West Virginia University, Morgantown, 2006, p. 2
[24] *Ibid.* at 631-632.

As the longwall panel advances, the surface topography experiences both tension and compression. The tensile forces open surface cracks, which can allow water to drain from the surface as the face advances, however the compression forces the fractures to close (

Figure 7). In 1979, Francis Kendorski published a model that predicts the limit of fracturing based on seam thickness. It was developed through a review of studies conducted in Appalachia, Illinois, the USSR, UK, India, and Australia. This model was updated in 1993.[25] Kendorski defines five zones above a longwall excavation: Caved Zone, Fractured Zone, Dilated Zone, Constrained Zone, and Surface Fracture Zone (

Figure 7).

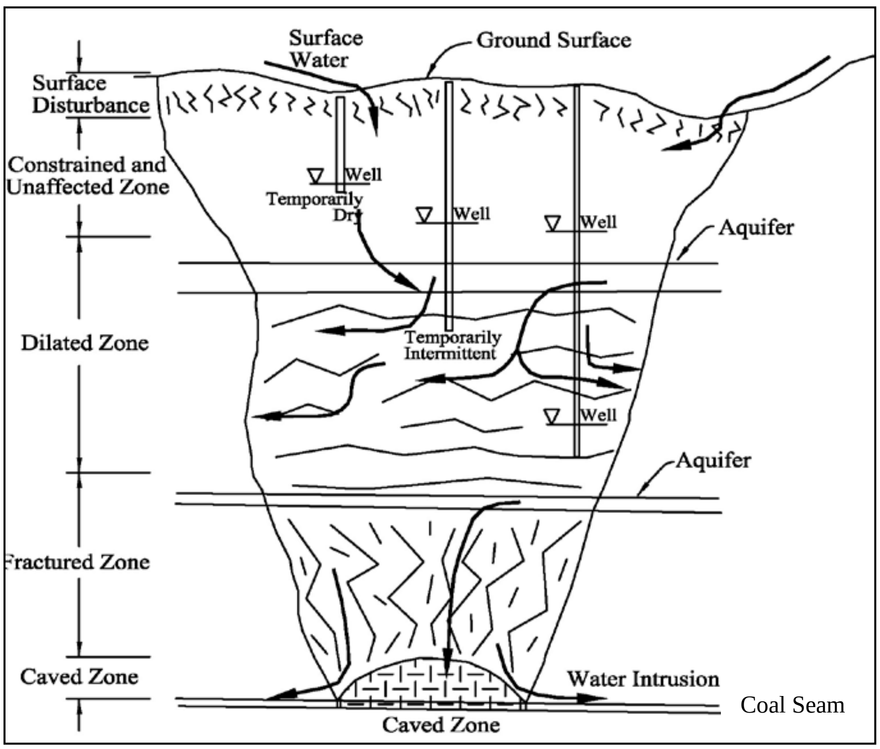

Figure 7: Diagram of Zones of Fracturing[26]

Kendorski defined the "Caved Zone" as the zone of roof failure with rubble depth ranging from three to six-times the height of the void created by the excavation. The "Fractured Zone" can extend above the "Caved Zone" to a height ranging from 24 times to 30 times the height of the void. This zone is

[25] Kendorski, F.S., "Effect of Full-Extraction Mining on Ground and Surface Waters," Proceedings, 12th Intl. Conference on Ground Control in Mining, West Virginia University, Morgantown, pp. 412-425, 1993.

[26] Kendorski, F.S., (Adapted from) "Effect of Full Extraction Underground Mining on Ground and Surface Waters." *Proceedings, 12th Intl. Conference on Ground Control in Mining*. West Virginia University, Morgantown, pp. 412-425, 1993.

comprised of “continuous open fractures”. If these fractures should intersect a groundwater source, they could redirect flow to the "Caved Zone". The "Dilated Zone" is a zone of increase groundwater storativity with little or no enhanced vertical hydraulic conductivity. This zone can be affected by subsidence (i.e. sagging) but does not contain connective fractures to the zones below it. The "Constrained Zone" incurs little effect from subsidence at depths greater than 60 times the height of the void plus 50 feet. However, when faults, joint patterns, and other features are present, localized strain effects may occur. The "Surface Fracture Zone" extends only 50 feet below the surface. In this context, fractures formed in the "Surface Fracture Zone" are due to subsidence and are not related to the Stress-Relief zone shown in Figure 16 and Figure 17 .

Generally, a longwall mining operation will not cause permanent stream loss as long as the "Fractured Zone" does not intersect the "Surface Fracture Zone". Using Kendorski’s model, the minimum overburden thickness should not be less than 30 times the excavation height plus 50 feet. For a 6-foot seam, this threshold thickness would be 230 feet. If the overburden depth is less than the amount determined by using this formula, the "Fractured Zone" may intersect the "Surface Fracture Zone", forming continuous drainage pathways to the mined area. The Kendorski model does not specifically address the near surface groundwater zones formed by stress-relief fracturing.

Understanding the stress relief zone provides a framework for understanding how longwall mining can affect near-surface groundwater resources. Subsidence, whether caused by longwall mining or by full seam extraction room-and-pillar mining, can result in tension and compression in the near surface zone. Subsidence-induced movements can cause stress-relief fractures to open or close and reduce or enhance their hydrologic connectivity. If the fractures expand then groundwater storage and effective transmissivity increases. Likewise, expansion or contraction of fractures can transform connectivity pathways and alter groundwater movement. [27]

In addition, fracture development and movement in the stress-relief zone (Figure 16) can cause temporary disruption to stream flow. As fractures open and close due to subsidence-induced strains, groundwater will move to areas of higher conductivity. Over time, streams may recover as the expanded fracture zone is filled and the hydraulic gradient reaches equilibrium.

Factors that may affect subsidence impacts on groundwater resources include proximity to mining (Figure 16), mining sequence, geology, coal extraction percentage, thickness and strength of overburden, height of coal void, topography and presence of pre-existing fracture sets which extend mining-induced hydrologic impacts.[28]

Thus, while overburden thickness is not the sole factor controlling subsidence effects, generally the thicker the overburden, the less likely that subsidence fractures will induce permanent stream loss. Local factors can vary widely between mining operations and, therefore, cannot be readily incorporated into a regional analysis.

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[27] California University of Pennsylvania, "The Effects of Subsidence Resulting from Underground Coal Mining on Surface Structures and Features and on Water Resources: Second Act Five-Year Report", 2005.
[28] Callaghan, Fleeger, Barnes and Dalberto, "Groundwater Flow On The Appalachian Plateau of Pennsylvania", 1998.

2.9 Regional Approach to Subsidence Analysis

While several predictive models of subsidence exist, they are generally limited in focus and are not expandable to a regional level. Therefore, a literature review was conducted to assess physical characteristics that are most conducive to a regional analysis. This review indicated that the application of an overburden threshold limit appears to be the most logical approach for subsidence assessment on a regional level. Therefore, a review of threshold limits was conducted for the three major longwall producing regions: Northern Appalachia, Illinois Basin, and the Colorado Plateau.

Northern Appalachian geology is dominated by sandstone, shale, and intermittent coal seams. A study, "The Response of a High Order Stream to Shallow Cover Longwall Mining in the Northern Appalachian Coalfield" by Owsiany and Waite[29], indicates that 400 feet of overburden depth is adequate to prevent permanent stream loss. This study was presented in the 20th International Conference on Ground Control in Mining. Based on this study and other information gathered from the literature review, 400 feet was selected as the threshold depth for the Northern Appalachian region.

The Illinois basin contains shale with plasticity properties and glacial drift, and therefore, threshold overburden depths are difficult to define with certainty. The physical and hydrologic properties of glacial till help to isolate it from disturbances caused by subsidence. A series of studies[30] by the Illinois State Geologic Survey on the available coal resources throughout the state indicated that underground coal could be mined at overburden depths greater than 75 feet, depending on the thickness and competency of the bedrock. An inventory of current longwall mines revealed that companies are mining at overburden depths greater than 200 feet. Therefore, a 200-foot overburden threshold depth was chosen for the purposes of this assessment and to apply a consistent methodology for analysis across regions. (See the Disclaimers section below.)

Overburden in the Colorado Plateau is typically dominated by massive sandstone strata overlain by thinner layers of shale, siltstone and/or limestone. Generally, the mines in the Colorado Plateau operate at greater depths than in many other longwall mining areas in the United States. The 500-foot threshold overburden depth[31] is used only for the purposes of this assessment and to apply a consistent methodology for analysis across regions. (See the Disclaimers section below.)

While conditions could allow for longwall mining in areas with less overburden or result in permanent stream loss at deeper overburden depths, this analysis focuses primarily on the relationship between longwall mining and overburden depth. This approach allows for a broad-based regional analysis by identifying large areas where longwall mining presents an increased risk of permanent stream loss. It should be noted that this study does not identify or address high-risk areas where stream loss is probable.

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[29] Owsiany, J.A. and Waite, B.A., "The Response of a High Order Stream to Shallow Cover Longwall Mining in the Northern Appalachian Coalfield", 20th International Conference on Ground Control in Mining, 2001

[30] Treworgy, C.G., et al., "Availability of Coal Resources for Mining in Illinois", Illinois State Geologic Survey, 1998

[31] Wilkowske , C.D. and Cillessen, J.L., "Hydrologic conditions and water-quality conditions following underground coal mining in the North Fork of the Right Fork of Miller Creek drainage basin, Carbon and Emory Counties, Utah, 2004-2005" USGS Scientific Investigations Report 2007-5026, 2007.

2.10 Disclaimers

Determining with accuracy the site-specific variables that influence the propagation of subsidence effects to the surface and their ultimate influence on the hydrologic balance are exceptionally difficult tasks. Additionally, expanding a site-specific analysis to a regional study increases its complexity by several orders of magnitude as more variables are considered. These challenges influenced the development of this assessment.

To evaluate the effects of subsidence from longwall mining, assumptions that simplified the analytical process were made. A single variable, overburden threshold depth, was chosen since it had been previously studied and could be readily modeled. Overburden depth is measured from the top of the coal seam to the surface. For the purpose of this report, overburden depth in the Illinois Basin is measured from the top of the coal seam to the base of the unconsolidated material (glacial till).

Most subsidence related literature is centered in the Appalachian basin. This information provided the basis for most of the analysis included in this assessment. Northern Appalachia is generally more developed than other regions with numerous manmade structures in place that could experience impacts from subsidence following the extraction of an underlying coal seam. Therefore, this region is the most studied with regard to the potential consequences associated with coal mining related subsidence.

Also see Section 2.5 Limitations for more information. Disclaimers for this study are listed below.

a. Since this report is regionally based, methodology and conclusions originating, either partially or wholly, from this study should not be applied to specific mines or mining blocks.

b. After reviewing an inventory of longwall mines in the Illinois Basin, a threshold overburden depth of 200 feet was used. This threshold overburden depth is considered representative of the current mining practices in the Illinois Basin but may not be applicable where geologic anomalies or substantial glacial drift exist on a local level.

c. The threshold overburden depth (500 feet) used for the Colorado Plateau is in accordance with a study indicating that BLM required a minimum of 500 feet of overburden beneath perennial streams.[32] This threshold overburden depth may not be applicable where geologic anomalies or discontinuities exist on a local level. At least one mine in the region exhibited complete stream loss at depths up to 1,500 feet due to block faulting. While the damage was mitigated and the stream recovered, overburden depth did not seem to be as clear an indicator of potential to cause MDHB as in other regions. In addition, because the majority of mines were located on different coal seams and overburden and localized geologic conditions varied, this analysis could not be expanded to a regional level. Although most mines in this coal region are located at depths that should lessen concerns related to permanent stream loss, impacts could still occur, even in deeper mines. However, since at least one example exists of successful mitigation of stream loss, it appears that remedial measures are available. As with other regions, a

[32] Wilkowske ,C.D. and Cillessen , J.L., "Hydrologic conditions and water-quality conditions following underground coal mining in the North Fork of the Right Fork of Miller Creek drainage basin, Carbon and Emory Counties, Utah, 2004-2005" USGS Scientific Investigations Report 2007-5026 (2007).

detailed analysis of local conditions would need to be conducted to assess the viability of a particular proposed longwall mine.

d. The threshold overburden depth (400 feet) in Northern Appalachia is based on studies conducted in this region. This threshold overburden depth may not be applicable where geologic anomalies or discontinuities exist on a local level.

e. Due to varying local conditions, threshold overburden depth may not always be a reliable indicator of the potential for permanent stream loss.

3. MINOR LONGWALL PRODUCING REGIONS

Minor longwall producing regions were defined in the *Study Areas* section of this report. These regions include Central Appalachia, Southern Appalachia, and Northern Rocky Mountains and Great Plains. Approximate 2012 longwall production numbers for each region are shown below.

- Central Appalachia 12 million tons per year (tpy)
- Southern Appalachia 12 million tpy
- Northern Rocky Mountains 18 million tpy

Together these regions comprise only about 15 percent of the total U.S. longwall production. The following sections briefly discuss each of these regions.

3.1 Central Appalachia

Central Appalachia consists of coalfields located in eastern Kentucky, southwest Virginia, northern Tennessee, and southern West Virginia. Coal production in Central Appalachia has declined signifiantly from its peak production in 2006 of about 236 million tons to about 147 million tons in 2012. However, the percent of longwall production has risen from a low of 7% in 2007 to its current high of 15% in 2012. For Central Appalachia, longwall production originates from one mine located in Virgina and four mines in West Virgina. Longwall mining in Southern West Virginia is in four seperate seams, while in Northern Appalachia longwall mining is almost exclusively in the Pittsburgh Seam. The West Virginia mines, with approximate 2012 production tons, are shown below.

- Justice No. 1 Mine 0.8 million tons
- Mountaineer II Mine 2.5 million tons
- Pinnacle Mine 2.4 million tons
- American Eagle Mine 2.3 million tons

Table 16 list details for each West Virginia longwall mine.

Mine Name	Permittee	WVDEP Permit No.	Longwall Seam	Approx. Overburden Depth (ft)[33]	County	Quad	Latitude	Longitude
Justice No. 1	Independence Coal Company	U501398	No. 2 Gas	340' min 400+ avg	Boone	Madison	38-0-56	81-45-15
Mountaineer II (Alma No. 1)	Mingo Logan Coal Company	U503197	Alma	440' min	Logan	Clothier	37-54-43	81-47-55
Pinnacle Mine	Pinnacle Mining Cmpany LL	U020483	Pocahontas	600' min	Wyoming	Mullens	37-32-42	81-29-30
American Eagle	Panther, LLC	U039100	Eagle	640' min	Kanawha	Cedar Grove	38-9-51	81-28-5

Table 16: Central Appalachia WV Longwall Mine Details[34]

[33] Overburden depths are based on a visual examination of mine drawings submitted to the West Virginia Division of Environmental Protection (WVDEP)

[34] Mine details from information provided by the West Virginia Division of Environmental Protection (WVDEP)

Overburden depths for Central Appalachian longwall mines appear to be, most cases, greater than the 400 foot threshold depth proposed for the Appalachian Basin. The Justice No. 1 mine in Boone County, West Virginia has an minimum overburden depth of about 340 feet. However, this is only for a small section of one panel. Most other overburden depths for this mine are well over the 400 foot threshold. The minium overburden depth for the Alma No. 1 mine is about 440 feet. Similar to the Justice mine, the Alma No. 1 mine operates at overburden depths greater than 400 feet. The Pinnacle and American Eagle mines both operate above 600 feet of overburden.

Central Appalachia has experienced an extensive history of mining. Surface and underground mining have been employed on small and large scales, depending on the available capital, market demands, economic, and other conditions. Previous mining has targeted seams that are the most economical and least challenging to recover. The remaining coal reserves in Central Appalachaia are generally bounded by partially-mined coal seams, creating a more difficult and hazardous environment for extracting residual resources. Conditions that may limit longwall mining include existing underground works above and below the targeted seam, and geologic anomalies.

In this region, determining the type of mining method employed by a particular mine may be difficult. For instance, longwall mining may be used for a period, depending on the seam height and other factors, and later, the mining operator may revert back to the more flexible room and pillar mining method to recover less favorable reserves in an effort to balance the safety of the working conditions.

3.2 Southern Appalachia

Southern Appalachia encompasses coalfields in southern Tennessee, northern Alabama, and northwestern Georgia. Coal production in Southern Appalachia has remained at about 20 million tons from 2003 through 2012 with longwall production consisting of more than half of the overall production. Longwall production peaked at about 15 million tons in 2003 and 2004 and is currently at about 12 million tons per year. For 2012, longwall production originated from five mines: Oak Grove mine, Shoal Creek mine, Blue Creek #4 mine, Blue Creek #7 mine, and the North River #1 mine. All of these mines are located in Alabama.

Alabama longwall operations generally operate in the Blue Creek seam with overburden thickness of over 1,000 feet.[35] Given the geology in Alabama and their longwall mining depths, MDHB due to permanent stream loss is not likely to occur.

3.3 Northern Rocky Mountains and Great Plains

The Northern Rocky Mountains and Great Plains region includes coal fields in Montana, North Dakota, Wyoming, and eastern Colorado. Three longwall mines are currently operating in this region: Bull Mountains in Montana, Bridger Underground in Wyoming, and Foidel Creek in Northwestern Colorado. Production from these three mines totaled about 18 million tons in 2012. Coal productivity trends from 2003 to 2012 project a moderate increase in longwall production for the foreseeable future.

[35] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 24.

Beginning at an existing highwall, the Bull Mountains mine developed five portals to access a large block of coal in the Mammoth coal seam. Longwall panels were designed for a minimum of 200 feet of overburden depth. Two large shale beds, totaling about 60 feet in thickness, lie about 110 feet above the Mammoth coal seam. [36] These shale beds will likely deform plastically and inhibit stream loss from subsidence. Given the geology and site-specific information, coupled with hydrologic balance protection required at 30 CFR 817.41, MDHB due to permanent stream loss has minimal potential to occur.

The Bridger Mine is located near Point of Rocks , Wyoming and exclusively serves the Jim Bridger Power Plant. This mine extracts coal from the Fort Union Formation. [37] The mineable seam ranges from 7 feet to 17 feet in thickness. The overburden consists primarily of sandstone and shale beds. The mine was originally a surface mine until stripping ratios became excessive, and then it was converted to a longwall mining operation. The overburden thickness above the longwall panels ranges from about 400 feet to nearly 1000 feet.[38] Given the geology and site-specific information, coupled with hydrologic balance protection required at 30 CFR 817.41, MDHB due to permanent stream loss has minimal potential to occur.

The Foidel Creek Mine is owned by Peabody Energy's Twentymile Coal Company and is located about 24 miles southwest of Steamboat Springs, Colorado. Production from the mine totaled 8 million tons in 2012. The mine extracts coal from the Wadge seam, which ranges in height from 8.5 feet to 10 feet.[39] Overburden thickness ranges from 800 feet to 1700 feet on their Sage Creek Lease.[40]

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[36] Environmental Assessment, Bull Mountains No. 1, Federal Lease MTM 97988, Musselshell County, Montana, DOI-BLM-MT-C010-2009-0010-EA., 2009.

[37] Environmental Assessment, Bridger Coal Lease Modification to WYW154595, WY-040-EA12-19, January 2013

[38] Maleki, H., Pollastro, C., "Geotechnical Program at Bridger Coal Company", 2008.

[39] Sollars, P.K., et al., "Twentymile Coal Company's Underground Conveyance System", 2000

[40] O'Mara,Marty, et al., "Combined Geology and Engineering Report and Maximum Economic Recovery Report for Sage Creek Lease",

4. ILLINOIS BASIN

The Illinois Basin is a subsurface structural feature that encompasses most of Illinois and extends into Indiana and Kentucky. See Figure 8. The Illinois Basin was once part of a larger basin that continued southward into the Mississippi Valley. During the Paleozoic Era, uplifting along the basin's southern boundary formed its current limits. At the floor of the Illinois Basin, Pennsylvanian rock plunges to about 2000 feet below sea level.[41] See Figure 9. During and after the Paleozoic era, the basin filled with approximately 100,000 cubic miles of primarily carbonate and siliciclastic rocks, and was subsequently buried by glacial till in most areas of the basin north of the Ohio River.[42]

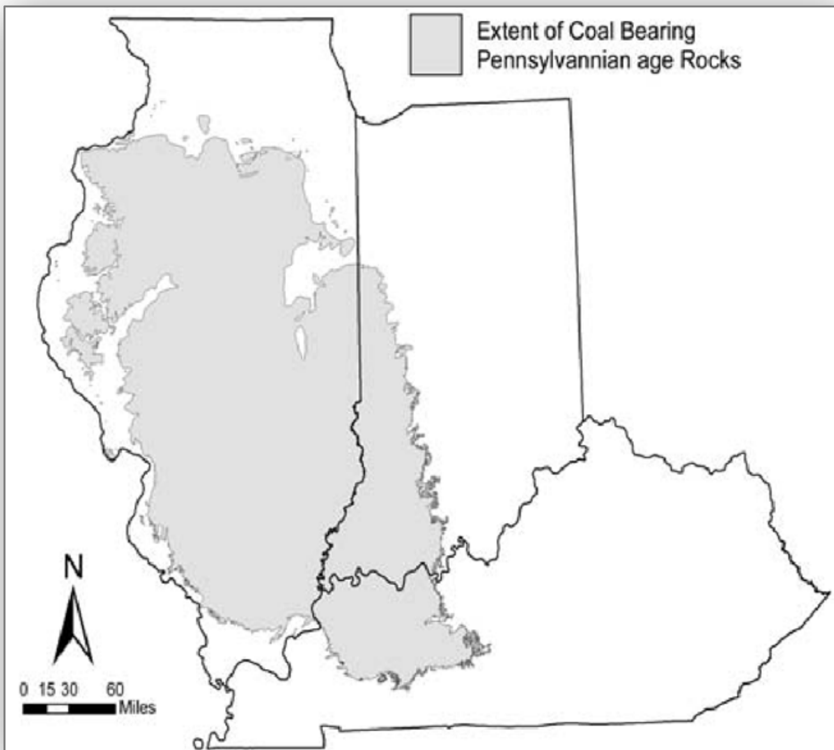

Figure 8: Pennsylvania Coal-Bearing Area in Illinois Basin (from Longwall Mining in Illinois: A Controversy over Planned Subsidence of Flat Farmland by Daniel Barkley, Illinois Department of Natural Resources.)

The distinct concave geometry of the Illinois Basin also resulted in extreme elevation differences for coal seams, including the Herrin and Springfield seams, which formed along its profile. These seams vary in elevation by over 1000 feet across the region. See Figure 9 and Figure 10.

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[41] Weller, J. Marvin, and Bell, Alfred H., "Illinois Basin", 1937.
[42] Kolata, Dennis R. and Nelson, John W., Illinois State Geological Survey, "Tectonic History of the Illinois Basin", 1990.

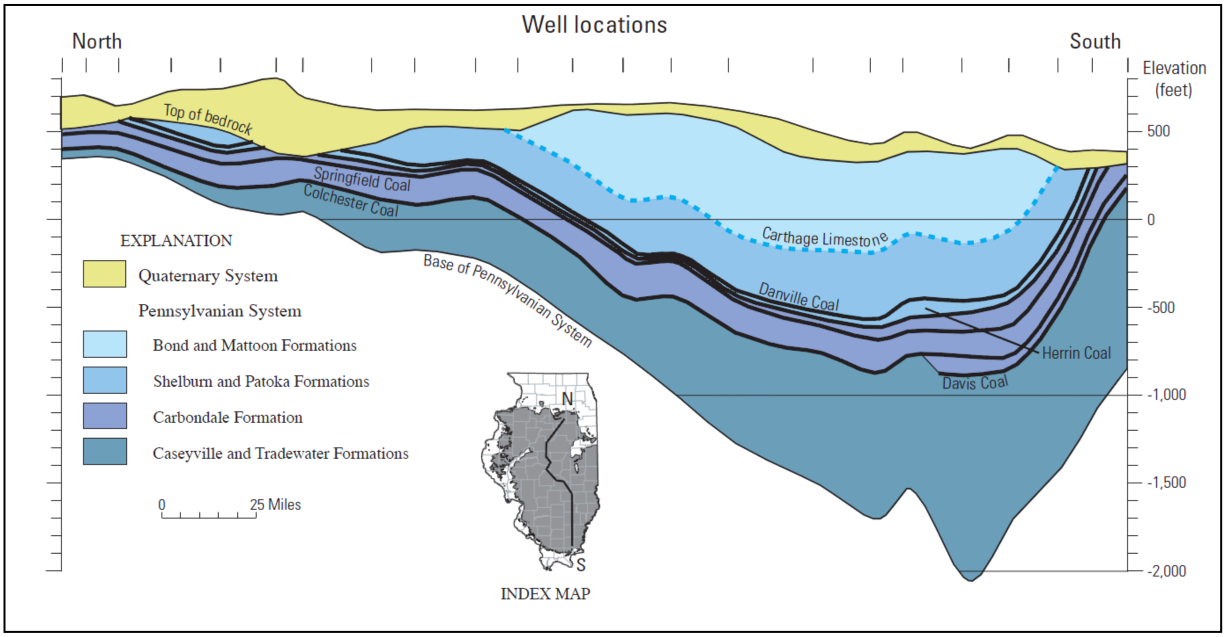

Figure 9: Generalized north-south cross section of the Pennsylvanian System in Illinois. (from U.S. Geological Survey Professional Paper 1625-D.)

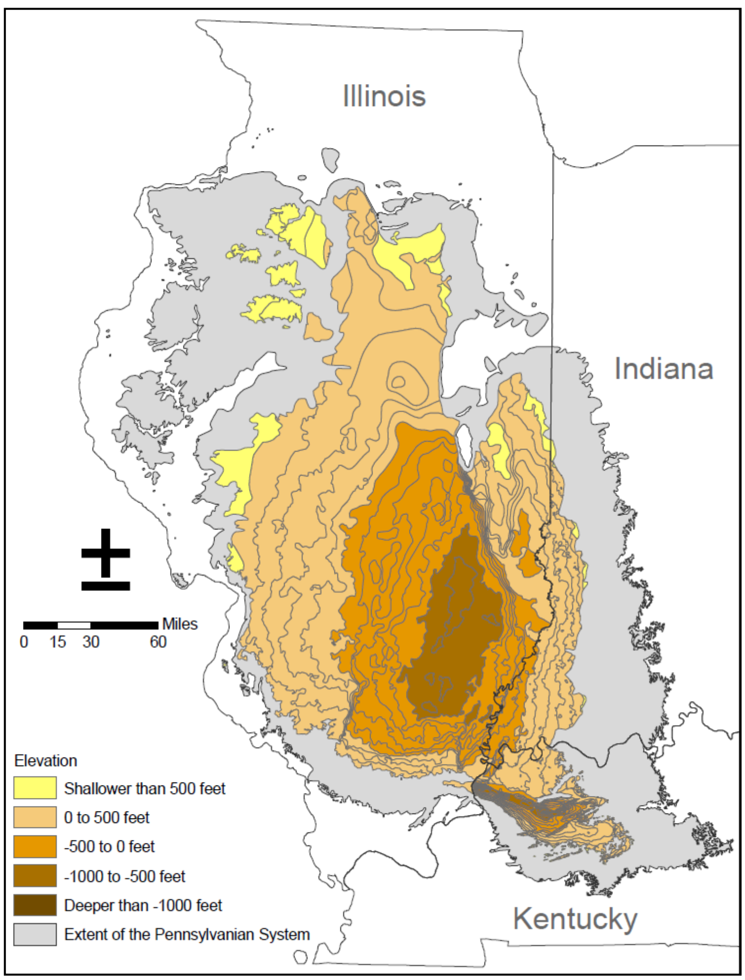

Figure 10: Elevation of Herrin Coal (from Illinois Basin: Geology and Characterization at the Tanquery site (MGSC), presented by David Morse, Illinois State Geological Survey, University of Illinois. 2011.)

The contrast between the hydrological regimes of Appalachia and the Illinois Basin is considerable.

The Appalachian coalfield generally consists of bedrock outcrops in hilly terrain. Appalachian aquifers were formed in bedrock fractures after periods of weathering and stress-relief and in the alluvial/colluvial material remaining in valleys after down-cutting, erosional events. Shale and coal strata act as aquacludes below the fractured zones. At higher elevations, some of these fractured, water-bearing zones are almost entirely localized.

The Illinois Basin consists of generally flat terrain. Much of the coal seams are overlain with glacial drift that varies from depths of 10 feet to over 200 feet in some areas. See Figure 11. Where glacial drift consists of finer till, groundwater flow is inhibited and bedrock fractures are less developed.[43] Coal strata in the Illinois Basin typically underlie sedimentary rock, such as shale and sandstone, which were formed in subsequent dispositional periods.

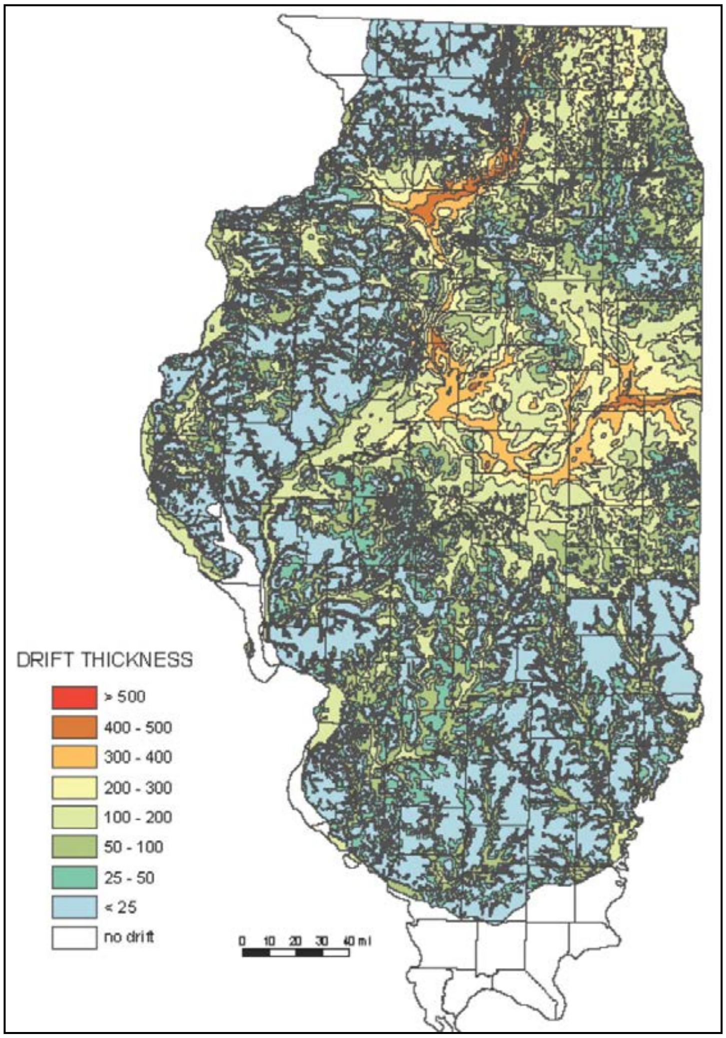

Figure 11: Map showing glacial and post-glacial deposits overlying bedrock. (from Illinois State Geologic Survey.)

[43] Booth, Colin J., Department of Geology, Northern Illinois University. "Hydrogeologic Impacts of Underground (Longwall) Mining in the Illinois Basin", 1986.

4.1 Subsidence Influences on Glacial Drift and Bedrock Aquifers

Where the glacial drift consists of finer particles, it tends to inhibit groundwater movement near the surface and the development of fracture zones in underlying bedrock aquifers. At least one study indicated that fine glacial drift can limit the response of the water table to subsidence events.[44]

Bedrock aquifers in the Illinois Basin are generally sandstone with low hydraulic conductivity. The hydrogeologic responses of bedrock aquifers to longwall mining in Illinois tend to follow similar patterns to those observed in Appalachia. In bedrock, subsidence can cause fracturing and dilation of joints and bedding planes. This movement can locally increase hydraulic conductivity and aquifer storage capacity.[45]

In the Illinois Basin, subsidence from longwall mining can have markedly different effects than in Appalachia. Shale layers in the overlying strata tend to exhibit plastic qualities that allow them to sag over a caving zone with only minor fracturing. The plasticity of the shale typically prevents groundwater migration into lower stratum. However, subsidence still has the potential to disrupt groundwater flow and cause drainage into an underground mine, wherever its location. The subsidence trough will normally recharge and restore groundwater to pre-mining levels.[46]

Recently, central Illinois has experienced subsidence impacts from longwall mining in the Herrin Coal seam. The depth of the Herrin coal seam is between 280 and 370 feet, and its thickness is between 5.5 and 8 feet. Figure 12 shows the extent and thickness of the Herrin Seam. The maximum subsidence is over five feet. Above the mine, prime farmland, which slopes at less than 0.5 percent, has subsided, resulting in changes to drainage patterns. Because the water table normally lies near the surface, subsidence has also resulted in highly saturated soils and surface ponding.[47]

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[44] Booth, Colin J., Department of Geology, Northern Illinois University. "Hydrologeologic Impacts of Underground (Longwall) Mining in the Illinois Basin", 1992.
[45] *Id.*
[46] Veith, David L, , "Mined Land Subsidence Impacts on Farmland with Potential Application to Illinois: A Literature Review", Bureau of Mines Information Circular, 1987.
[47] Barkley, Daniel, Mining Engineer and Subsidence Specialist, Illinois Department of Natural Resources, Office of Mines and Minerals, Springfield, Illinois, "Longwall Mining in Illinois: A Controversy over Planned Subsidence of Flat Farmland", 2007.

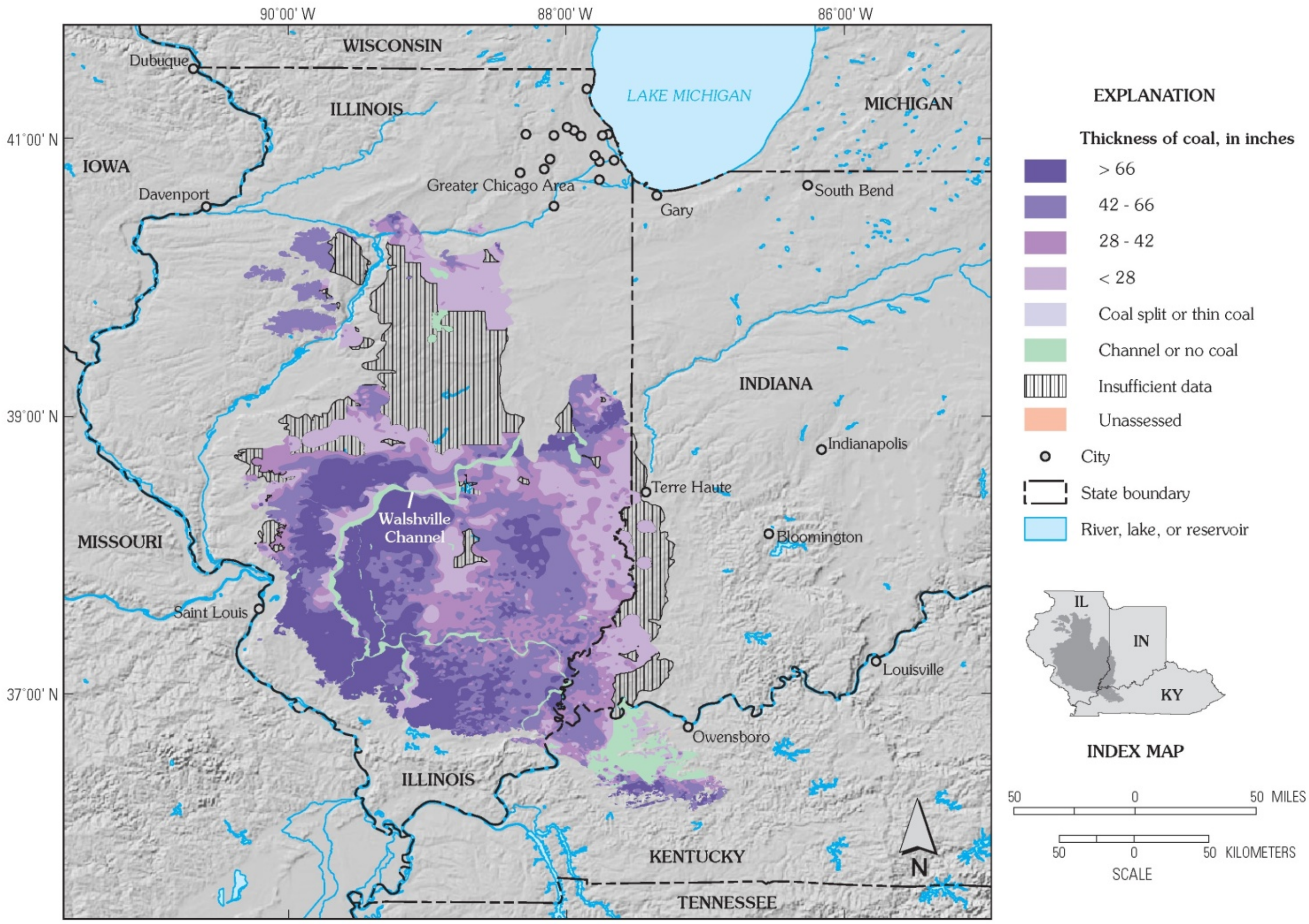

Figure 12: Map showing thickness of the Herrin Coal in Illinois, Indiana, and western Kentucky. (from U.S. Geological Survey Professional Paper 1625-D.)

4.2 Current Longwall Mines

Based on a review of the 2012 U.S. Longwall Census, all current longwall mines in the Illinois Basin are located in the state of Illinois and are producing coal from the Herrin No. 6 and Springfield seams. The names of these mines are: Mach Mining, New Era, New Future, Sugar Camp, and Hillsboro.[48]

In October 2011, permit data was obtained from the Illinois Division of Land Reclamation (IDLR) in Springfield. A summary of Illinois longwall mining operations is shown in Table 17.

[48] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 24.

Mine Company	Mine Name	Permit Number	Coal Seam	Geology/Overburden Characteristics	Overburden Thickness	Notes
Foresight Energy	Sugar Camp Mine	382	Herrin #6	Predominantly shale beds, followed by sandstone with some limited limestone layers. 56-76% shale, 13-40% sandstone, limestone present but mostly insignificant.	Maximum overburden thickness ranges from 590 to 885 feet with an average of 745 feet.	
Foresight Energy	Mach Mining Pond Creek Mine	375	Herrin #6	59-80% shale, 11-34% sandstone, limestone present but mostly insignificant.	534-561 feet	
Foresight Energy	Deer Run Mine	399	Herrin #6	Predominantly shale beds. 51-71% shale, minor limestone and sandstone beds.	447-552 feet, average of 491 feet.	
Alliance Resources	White Oak Mine	409	Herrin #6	Dominated by shale; some sandstone, and some interbedded limestone.	940-1090 feet	
Murray Energy	Gallatia Mine #5 and #6	2	Herrin #6 and Springfield/Harrisburg #5	No geologic information was available.	475-600 feet above the #5 seam and 375-500 feet above the #6 seam. Interburden thickness between the two seams	The mine has been longwall mining for 25 years and no history of stream loss or impacts have occurred that would be considered MDHB under the comtemplated SPR.
	Shay Mine #1 (formerly Monterey #1)	56	Herrin #6	No geologic information was available.	250-300 feet	This permit was issued as one of the early SMCRA permits in 1983. Originally it was permitted as a room and pillar, limited extraction mine, but operations were converted primarily to longwall in 1994. 17 longwall panels were completed between 1994 and 2007. The Shay Mine currently operates exclusively as a room and pillar mine, however, no adverse impacts to the hydrologic balance that would constitute MDHB during longwall operations at the mine.

Table 17: Summary of Longwall Mining Operations in Illinois (compiled from Illinois permitting information)

As shown in Table 17, all of the longwall mines in Illinois operate at overburden depths greater than 200 feet. The Shay Mine #1 is the only mine to approach the 200-foot overburden depth threshold. For this mine, OSM’s oversight report did not indicate that impacts to the hydrologic balance had occurred.

4.3 Conclusions

For the Illinois Basin, all current mines are operating beyond the 200-foot threshold depth and future longwall mines are not expected to approach this limit. Results from one study indicated that the water table in the glacial drift recovered to near pre-mining levels within four years after longwall mining had passed.[49] Therefore, permanent stream loss (MDHB) does not appear to be a factor in this region. As a result, no further analysis of coal resources in this region is considered necessary.

[49] Roosendall, Van, Danny J., et al., "Final Report of Subsidence Investigations at the Galatia Site, Saline County, Illinois", 1997.

5. COLORADO PLATEAU

The Colorado Plateau extends into four states: Western Colorado, Utah, New Mexico, and Arizona. See Figure 13. Currently thirteen longwall mines are operating in this region. These mines include six (6) mines in Utah, six (6) mines in Colorado, and one mine in New Mexico. In 2012, the total longwall production from this region was about 43 million tons.

The Colorado Plateau once consisted of wetlands that bordered the shoreline of an ancient seaway. Peat deposits accumulated in these wetland areas during the Cretaceous Period eventually forming coal beds that now extend into four states: Utah, Colorado, New Mexico, and Arizona.

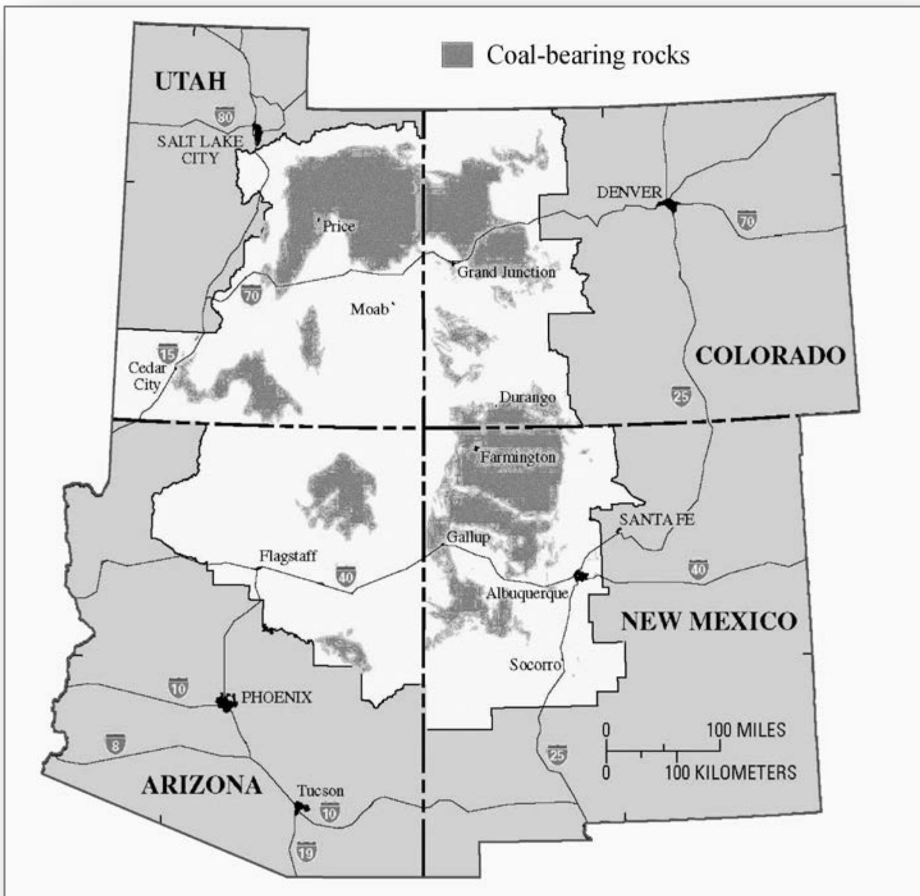

Figure 13: Colorado Plateau Coal-Bearing Areas (from USGS Fact Sheet FS-145-99 (Modified))

Longwall mining operations in the Colorado Plateau coal region generally occur in areas where overburden is thicker, compared to other coal regions, and is typically dominated by sandstone overlain by thin layers of shale, siltstone and/or limestone. A literature review indicated that overburden depths less than 500 feet would typically cause an increased risk of permanent stream loss where subsidence occurred beneath a stream[50].

5.1 Existing Mines

As with the Illinois Basin, permitting data was obtained for the longwall mines currently operating in the Colorado Plateau and an evaluation was made of stream impacts, if any had occurred. Table 18 summarizes the current longwall mining permits in Utah.

As shown in Table 18, the mines operate at depths much greater than the 500 foot threshold posited from the literature review, with the shallowest depth of cover at 900 feet.

In addition, a mining operation underlying U.S. Forest Service Land must receive authorization from the Forest Service to undermine a perennial stream. A review of the permit data revealed that the Sufco Mine, one of the first to receive authorization from the U.S. Forest Service to mine underneath a perennial stream, did cause impacts to the stream. Block faults from the mining operation, which was 1,500 feet below the perennial stream, developed all the way to the surface and drained the stream. However, the mine company was able to mitigate the temporary impact by sealing the fault and fractures with bentonite clay slurry. Afterward, the stream fully recovered.

The West Elk Mine in Colorado also caused similar stream impacts. It received authorization from the U.S. Forest Service to mine underneath a perennial stream and the results of block faulting appeared at the surface. In addition, several other longwall operations in Colorado operate, at least at some places, at depths close to the 500-foot overburden threshold.

Longwall mining operations, coal seam mined, and overburden depths in Colorado are shown in Table 19 below.

[50] Wilkowske, C.D. and Cillessen, J.L., "Hydrologic conditions and water-quality conditions following underground coal mining in the North Fork of the Right Fork of Miller Creek drainage basin, Carbon and Emory Counties, Utah, 2004-2005" USGS Scientific Investigations Report 2007-5026 (2007)

Mine Name	Typical Depth of Cover	Typical Overbuden Lithology	Formations
Dugout	1,000 - 1,700	massive, thickly layered fine grained sandstone overlain by thin to thick layers of siltstone, sandy silt-stone, limestone & shale	Blackhawk Castlegate Price River North Horn Flagstaff
Skyline	900 - 1,500	massive coarse grained sandstone interbedded with shale & silt shale overlain by layers of limestone shale & sandstone	Blackhawk Castlegate Price River North Horn Flagstaff Colton
Sufco	1,200 -1,800	massive coarse grained sandstone interbedded with shale & silt shale	Blackhawk Price River North Horn
Aberdeen	1,000 - 1,800	massive, thickly layered fine grained sandstone overlain by thin to thick layers of siltstone, sandy silt-stone, limestone & shale	Blackhawk Castlegate North Horn Colton
Lila Canyon	No LW activity	similar to West Ridge, Aberdeen, Dugout	<---
West Ridge	1,400 - 2,500	massive, thickly layered fine grained sandstone overlain by thin to thick layers of siltstone, sandy silt-stone, limestone & shale	Blackhawk Castlegate Price River North Horn Colton
Deer Creek	900 - 1,100	massive fine to coarse grained sandstone interbedded with shale & silt shale overlain by layers of limestone shale & sandstone	Star Point Blackhawk

Table 18: Longwall Mining Permits in Utah (compiled from Utah permitting information)

Mine Name	Mining Company	Seam Mined	Overburden Depth
Bowie Mines No. 2 (idle)	Bowie Resources	B	1,100-1,700 feet
Deserado	Blue Mountain Energy	B	400-900 feet
Elk Creek	Oxbow Mining	D	500-2,000 feet
Twentymile	Peabody Energy	Wadge	1,400-1,650 feet
West Elk	Arch Coal	E	600-1,200 feet

Table 19: Longwall Mines in Colorado[51]

[51] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 24.

Based on a review of permitting information and satellite imagery, longwall mining operations in Wyoming and New Mexico do not undermine perennial streams, and the single longwall mine in Montana does not undermine intermittent or perennial streams. In Wyoming, the Bridger Mine has a depth of cover of 700 feet. New Mexico's San Juan mine has overburden depths ranging from 400-900 feet[52], and no permanent loss of streams has been reported by the state regulatory authority or identified during OSM oversight.

5.2 Conclusions

The purpose of this assessment was to conduct a regional analysis to evaluate how longwall mining operations would be affected by a definition of "material damage to the hydrologic balance outside the permit area." For the Colorado Plateau coal region, most all current mines are operating above the 500-foot threshold depth and future mines are not anticipated to be less than 500 feet of overburden. Therefore, the occurrence of permanent stream loss due to longwall mining does not appear to be prominent in this region.

[52] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 26.

6. APPALACHIAN BASIN

The Appalachian Basin is divided into the Northern Appalachia, Central Appalachia, and Southern Appalachia coal regions. The total longwall production for the Appalachian Basin was about 106 million tons in 2010, making it by far the largest longwall coal producing region in the United States. Figure 14 depicts the areal extent of the Appalachian Basin coal regions.

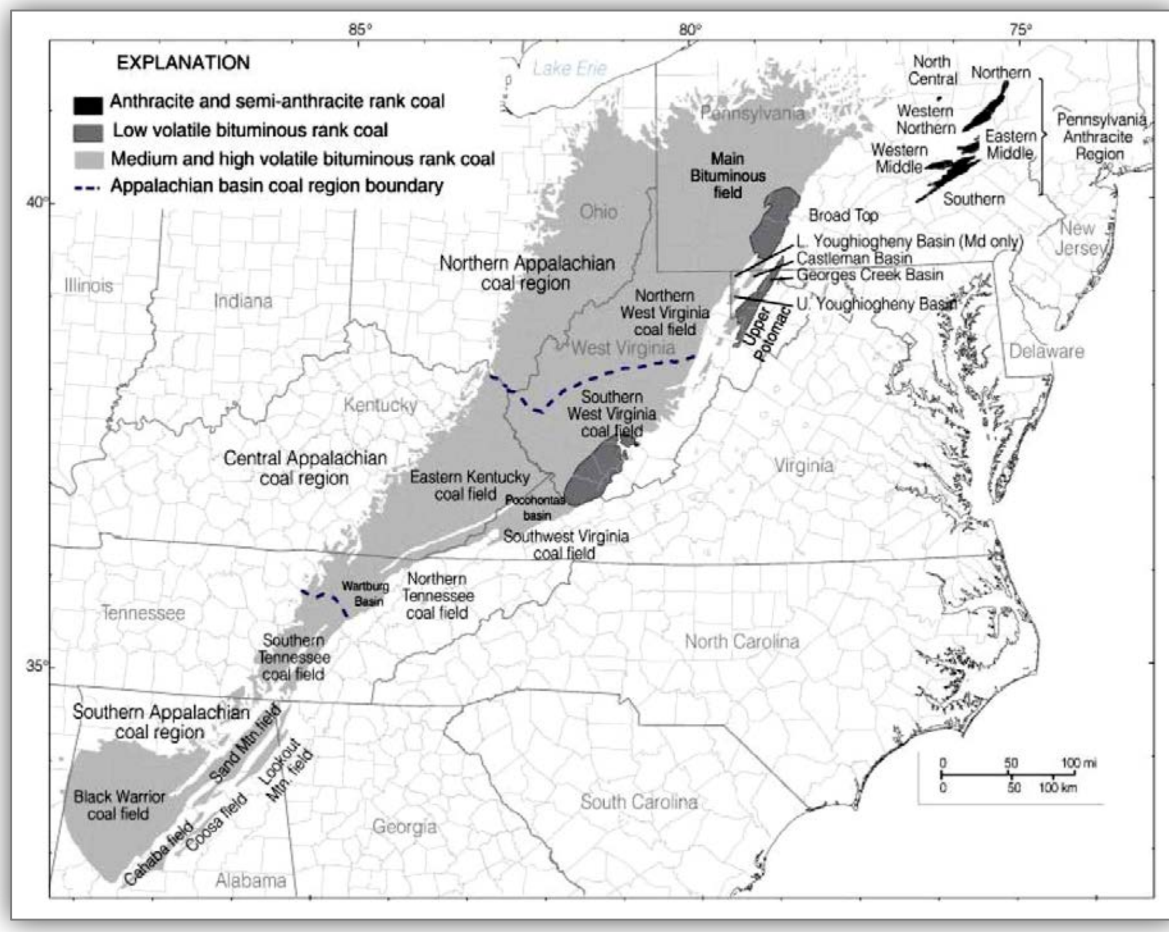

Figure 14: Appalachian Basin Coal Regions[53]

Longwall mining in the Appalachian Basin occurs predominantly in Southern Appalachia in Alabama and in Northern Appalachia in West Virginia, Pennsylvania, and Ohio.[54] While no model mine was created for Alabama longwall operations, these mines tend to operate in the Blue Creek seam with overburden

[53] Ruppert, Leslie F., et al, "Geologic controls on thermal maturity patterns in Pennsylvanian coal-bearing rocks in the Appalachian basin", 2010.

[54] Three longwall mines operate in Central Appalachia.

thickness greater than 1,000 feet. [55] Given the geology in Alabama and the depths at which mining typically occurs, MDHB due to permanent stream loss is not likely to occur.

However, in Northern Appalachia, a sub region of the Appalachian Basin, literature indicated that permanent stream loss was more likely to occur where depths of cover were less than 400 feet.[56] An assessment of the longwall operations in this region revealed that several mines have overburden depths less than 400 feet. Because the majority of these mines operate in the Pittsburgh seam, a geospatial analysis was conducted on a regional level to evaluate overburden depths in areas where longwall mining is occurring and the extent and location of shallower overburden depths. The geospatial analysis incorporated certain data such as past, present, and projected longwall mining boundaries and coal seam thicknesses.

In addition, only one longwall mineable seam can be analyzed at a time, since the model assesses longwall mineable coal based on seam thickness and overburden depth. While it is recognized that some longwall operations in Northern Appalachia mine seams other than the Pittsburgh seam, an analysis of these operations would be site specific since they all mine different seams. As with longwall operations in the Colorado Plateau coal region, operations in Northern Appalachia would require a site specific analysis of MDHB potential, which is determined by the regulatory authority for current and future operations. Although these seams can be evaluated geospatially a separate model for each longwall mineable seam was not part of this analysis.

6.1 Model Discussion

The geospatial analysis is limited to the Pittsburgh coal seam in Northern Appalachia, the northern section of the Appalachian Basin region discussed in the EIS. The majority of longwall mining in Northern Appalachia occurs in the Pittsburgh seam.[57] All longwall mining operations in Pennsylvania and Ohio mine the Pittsburgh seam and 8 of 13 longwall operations in West Virginia mine the Pittsburgh seam. Overall, about 45% of the 2012 longwall mining production comes from Northern Appalachia. While this includes the five longwall operations in seams other than the Pittsburgh, the Pittsburgh seam is by far the largest producing longwall mineable seam in the country.[58] Figure 15 shows longwall mining production in Pennsylvania, West Virginia, and Ohio from 2001 through 2010.[59]

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[55] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 24.
56 Owsiany, J.A. and Waite, B.A., "The Response of a High Order Stream to Shallow Cover Longwall Mining in the Northern Appalachian Coalfield", 20th International Conference on Ground Control in Mining, 2001
[57] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 24.
[58] EIA, Annual Coal Report 2010, Table 3 – Underground Production by State and Mining Method, available at www.eia.gov/coal/annual.
[59] EIA, Annual Coal Reports 2001-2010, Table 3 – Underground Production by State and Mining Method, available at www.eia.gov/coal/annual.

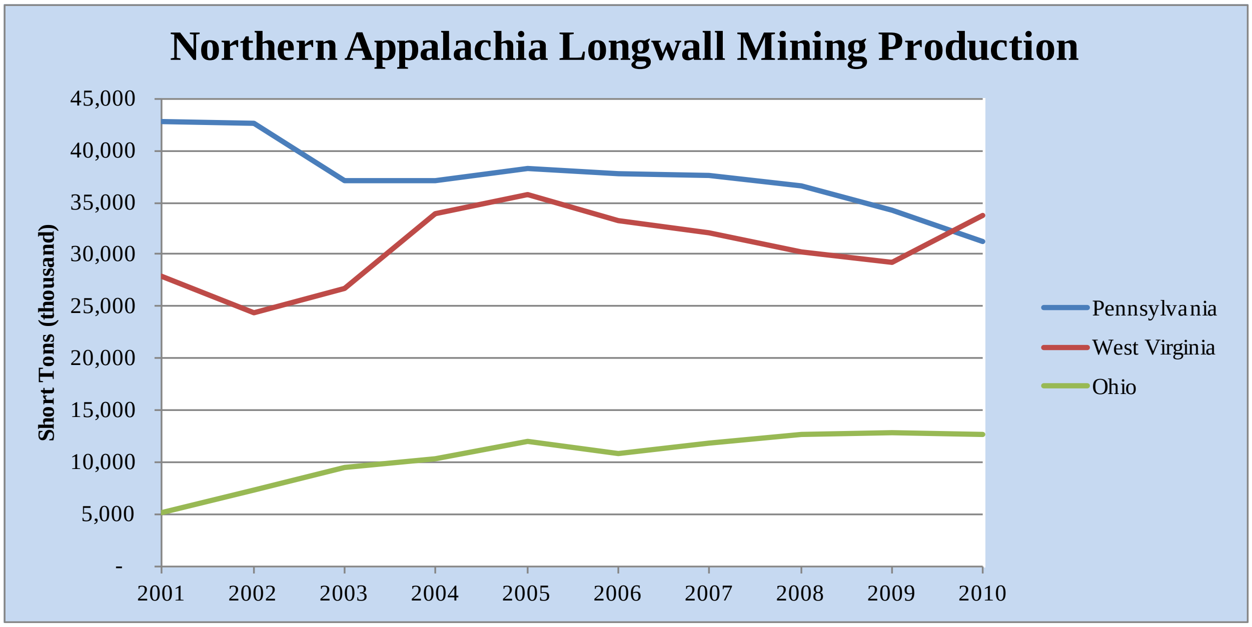

Figure 15: Longwall Mining Production in Northern Appalachia's Pittsburgh Seam, 2001-2010[60]

In addition, Northern Appalachia contains more longwall mining operations than any other region[61], several currently operating mines have overburden thicknesses approaching the 400 foot threshold posited in Appendix B[62], and data such as overburden thickness, coal seam height, mined area, and proposed permit boundaries were readily available.

The core goals of this assessment are as follows:

- Evaluate the effect of implementation of the proposed definition of MDHB in Northern Appalachia;
- Define the extent of the coal resource and longwall mineable reserves in the Pittsburgh seam, the most prominent longwall mineable seam in Northern Appalachia;
- Create a geospatial model depicting the location of longwall mineable reserves in relation to overburden depth;
- Compile the results of the analysis and discuss possible impacts on coal reserves and longwall mining; and
- Explain analytic assumptions and the limitations of the study.

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[60] *Ibid.*
[61] Fiscor, Steve "U.S. Longwall Census," Coal Age February 2012: 24.
[62] *Ibid.*

In assessing MDHB from underground mining operations, scientific research that shows an inverse relationship between overburden thickness and detrimental impacts to water quantity as a result of subsidence from longwall mining was relied upon.[63] Although other factors contribute to subsidence-related impacts, these parameters were not applied due to the conceptual nature of the model mines designed for this analysis. Since the model mines analyzed as part of EIS Appendix B are abstract and do not have a physical location, there are no biological data, water quality or quantity data, data on current stream use, or any groundwater mapping or lithologic data associated with these mines. In addition, because site specific factors that affect hydrologic impacts caused by mining operations vary widely, it was infeasible to take all of these variables into consideration. Thus, for underground mining operations, overburden depth was the primary variable used to assess whether permanent stream loss caused by subsidence would be likely to occur.

Based on the proposed definition of material damage to the hydrologic balance outside the permit area, it was assumed that any permanent stream loss caused by an operation would constitute MDHB and assessed whether MDHB would occur solely on this basis. Therefore, this analysis does not include an assessment of any adverse impacts to water quality or biological stream condition or any water quantity related impacts short of permanent and complete flow loss that would result in MDHB. Thus, even if this analysis does not predict the likelihood for material damage to the hydrologic balance outside the permit area to occur in certain locations, MDHB could still occur depending on site specific biological, chemical, and physical conditions.

6.2 Appalachian Geology and Groundwater Flow

The Appalachian region has experienced a long and complex history of mountain-building, weathering and deposition periods. Notably, in the Carboniferous Period (360 million years ago), thick layers of peat accumulated leading to the formation of extensive coal deposits. In the Permian Period (290 million years ago), another continental collision resulted in mountain building and renewed clastic deposition into the Appalachian Basin. By the end of the Permian Period, the Appalachian Basin changed from a depositional basin to an area above sea level. The next 250 million years were marked by extensive erosion and stream incision, creating the regional relief that is observed today.[64]

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[63] Stoner, J.D., et al., "Probable Hydrologic Effects of Subsurface Mining." Ground Water Monitoring Review. V. 3, no. 1, pp. 128-137, 1983.
Cifelli, R.C. and Rauch, H.W., "Dewatering Effects from Selected Underground Coal Mines in North-Central West Virginia." Proceedings 2nd Workshop on Surface Subsidence Due to Underground Mining. West Virginia University, Morgantown, WV, pp. 249-263, 1986.
Dixon, D.Y. and Rauch, H.W., "Study of Quantitative Impacts to Ground Water Associated with Longwall Coal Mining at Three Mine Sites in the Northern West Virginia Area. Proceedings, 7th Conference on Ground Control in Mining. West Virginia University, Morgantown, WV, 1988.
Dixon, D.Y. and Rauch, H.W., "The Impact of Three Longwall Coal Mines on Stream Flow in the Appalachia Coalfield.: Proceedings, 9th International Conference on Ground Control in Mining, West Virginia University, Morgantown, WV, pp. 169-182, 1990.
[64] Barnes, John H. and Sevon,W.D., "The Geological Story of Pennsylvania" (Pennsylvania Geological Survey, 4th Series) Harrisburg, 2002.

The removal of massive tons of bedrock caused a redistribution of internal forces within the remaining strata, creating stress-relief fractures that extend to about 300 feet below the surface.[65] Stress-relief fractures include vertical joints that formed along valley side-slopes as laterally supporting rock was dislodged and removed during erosional down-cutting. [66]

Slumping along the valley wall fractures caused compression in the valley floor, resulting in ground shifts that caused thrust faults, bedding-plane partings, arching, and vertical extension fractures above arches. The resultant highly permeable, stress-relief flow systems consist of interconnected valley-wall and valley-floor fracture sets. A confining layer of alluvial clay can cause segments of the groundwater subsystem to become artesian in the valley floor.[67] (Figure 16 and Figure 17)

In the Appalachia Plateau, secondary discontinuities such as fractures and bedding-plane partings provide an efficient medium for groundwater storage and movement. Fractures form the primary paths for groundwater flow in Appalachia due to their lower frictional resistance relative to the intergranular pores of sandstone. However, in this geologic setting, the hydraulic gradient exerts the greatest influence on the direction of groundwater flow.[68]

While conducting research in the Mercer, Pennsylvania quadrangle, Poth (1963) found shallow groundwater circulating in a series of "hydrologic islands" in hills surrounded by perennial streams. (Figure 19) A shallow, local groundwater system operates within each hydrologic island, functioning independently from groundwater systems in neighboring islands. Generally, the base of the local flow system lies below the level of the stream valleys bordering the islands. The local groundwater system receives recharge entirely from within the hydrologic island.[69]

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[65] Sames and Moebs, "Roof Instability Induced by Stress Relief Joints in Central Appalachian Drift Coal Mines. Journal of Coal Quality, Vol. 10, No. 3, 1991.
[66] Callaghan, Fleeger, Barnes and Dalberto, "Groundwater Flow On The Appalachian Plateau of Pennsylvania", 1998.
[67] Kipp and Dinger, "A Conceptual Model of Groundwater Flow in the Eastern Kentucky Coal Field." Symposium on Surface Mining, Hydrology, Sedimentology and Reclamation. University of Kentucky, Lexington, Kentucky, pp. 543-548, 1987.
[68] Poth, C.W., "Geology and Hydrology of the Mercer Quadrangle, Mercer, Lawrence, and Butler Counties, Pennsylvania. Water Resources Report 16. Pennsylvania Topographic and Geologic Survey, 4th Series, Harrisburg, PA, 149 p., 1963.
[69] Callaghan, Fleeger, Barnes and Dalberto, "Groundwater Flow On The Appalachian Plateau of Pennsylvania", 1998.

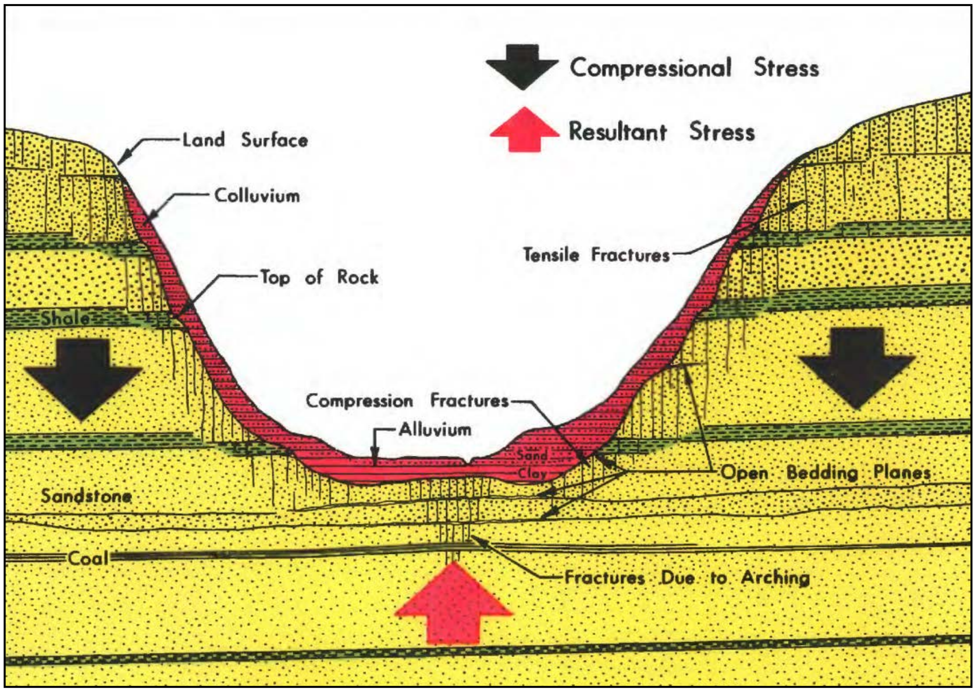

Figure 16: Generalized Geologic Section Showing Features of Stress-Relief Fracture[70]

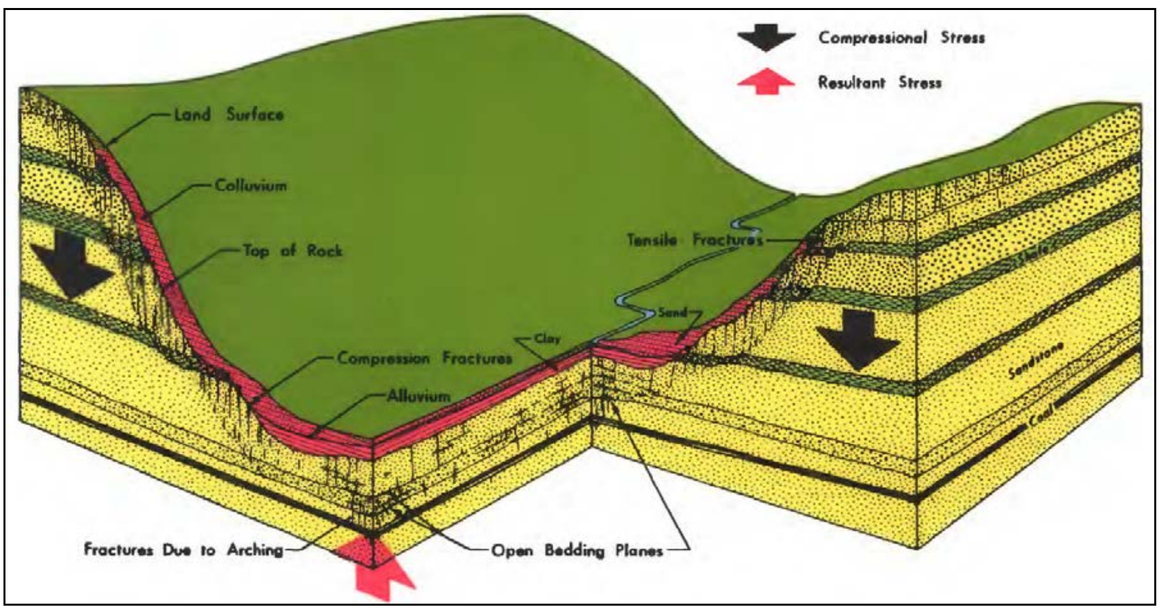

Figure 17: Block Diagram of Generalized Geologic Section Showing Features of Stress-Relief Fracturing[31]

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[70] Wyrick and Borchers, "Stress-Relief Fracturing In an Appalachian Valley." Geologic Survey Water-Supply Paper 2177, p. 13, 1981.

In the idealized depiction of groundwater flow shown in Figure 18, sandstone units are shown as aquifers and shale as aquacludes. Permeability in sandstones may be hundreds of times greater than in shale units.[71] Primary porosity is the intergranular pore space within sandstone while secondary porosity consists of the interconnected fracture network. Groundwater wells intersecting this fractured zone will generally have the greatest yields. Joints are rock fractures where displacement has not occurred. Systematic joints are dominate, incorporating local joints, and will extend nearly vertically through rock units. Systematic joints are often continuous and can transmit groundwater long distances and more rapidly than non-systematic joints. In Figure 19, the joints found beneath valleys are plenteous, consisting of both systematic and non-systematic joints.[72]

Deeper fractures or joints will connect intermediate groundwater flow to valley streams. Hydrostatic pressure forces groundwater upward through these joints to the streambed. The near surface fractured zone contributes the vast amount of well water for domestic use. Since fracturing diminishes with depth in this environment, studies have indicated that 99.9% of total groundwater circulation occurs within 175 feet of the surface.[73]

Flow systems can be classified as local, intermediate and regional. These classifications characterize the time required for groundwater to flow from a recharge area to a discharge area. Intermediate groundwater may take decades to circulate back to the surface while regional groundwater may take centuries.[74] See Figure 20.

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[71] Brown, R.L and Parizek, R.R., "Shallow Groundwater Flow Systems Beneath Strip and Deep Coal Mines at Two Sites", Clearfield County, Pennsylvania Special Research Report No. SR-84, The Pennsylvania State University, University Park, PA, 207 p., 1971.

[72] Callaghan, Fleeger, Barnes and Dalberto, "Groundwater Flow On The Appalachian Plateau of Pennsylvania", 1998.

[73] Stoner, J.D., Williams, D.R., Buckwalter, T.F., Felbinger, J.K., Pattison, K.L., "Water Resources and the Effects of Coal Mining, Greene County, Pennsylvania". Water Resource Report 63. Pennsylvania Department Environmental Resources, 166 p., 1987.

[74] Callaghan, Fleeger, Barnes and Dalberto, "Groundwater Flow On The Appalachian Plateau of Pennsylvania", 1998.

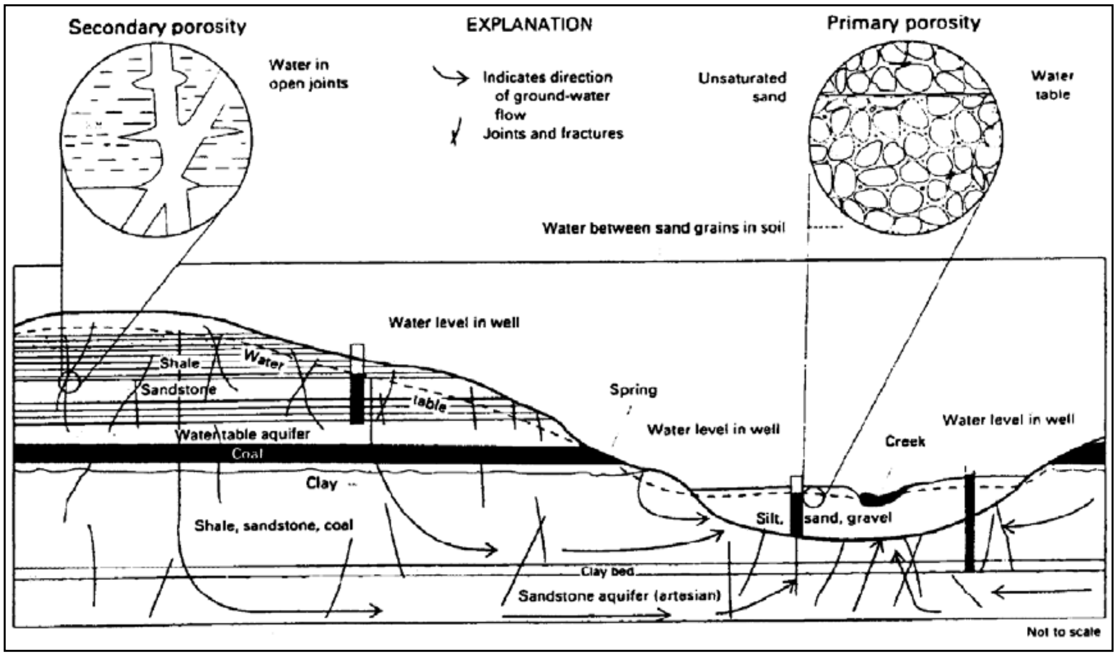

Figure 18: Water Table Aquifer (Upper), Confined Aquifer (Lower), and Groundwater Flow Lines[75]

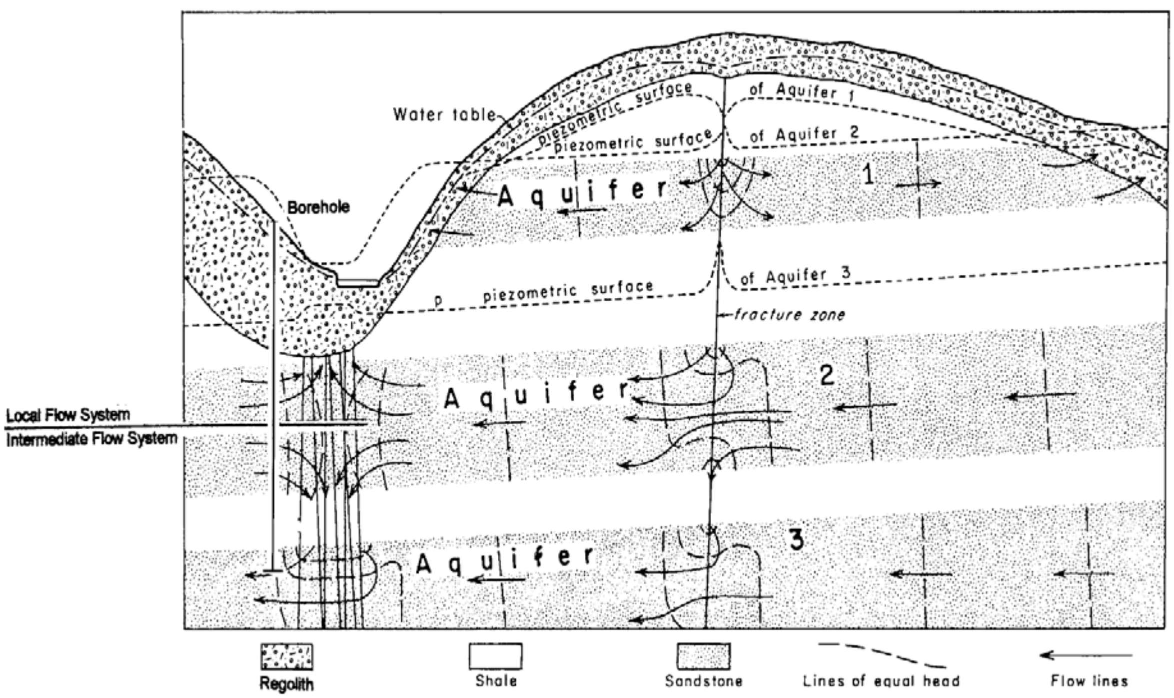

Figure 19: Idealized Pattern of Groundwater Flow to and Beneath a "Hydrologic Island"[76]

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[75] Hobba, W.A, (Modified from) "Ground-water Study 5, In: Ground-Water Information Manual: Coal Mine Permit Application -- Vol. II. OSMRE, U.S. Department of Interior, pp. 147-188, 1987.

[76] Poth, C.W., (Modified from) "Geology and hydrology of the Mercer quadrangle, Mercer, Lawrence, and Butler Counties, Pennsylvania", Water Resource Report 16, Pennsylvania Topographic and Geologic Survey, 4th Series, Harrisburg, PA, 149 p., 1963.

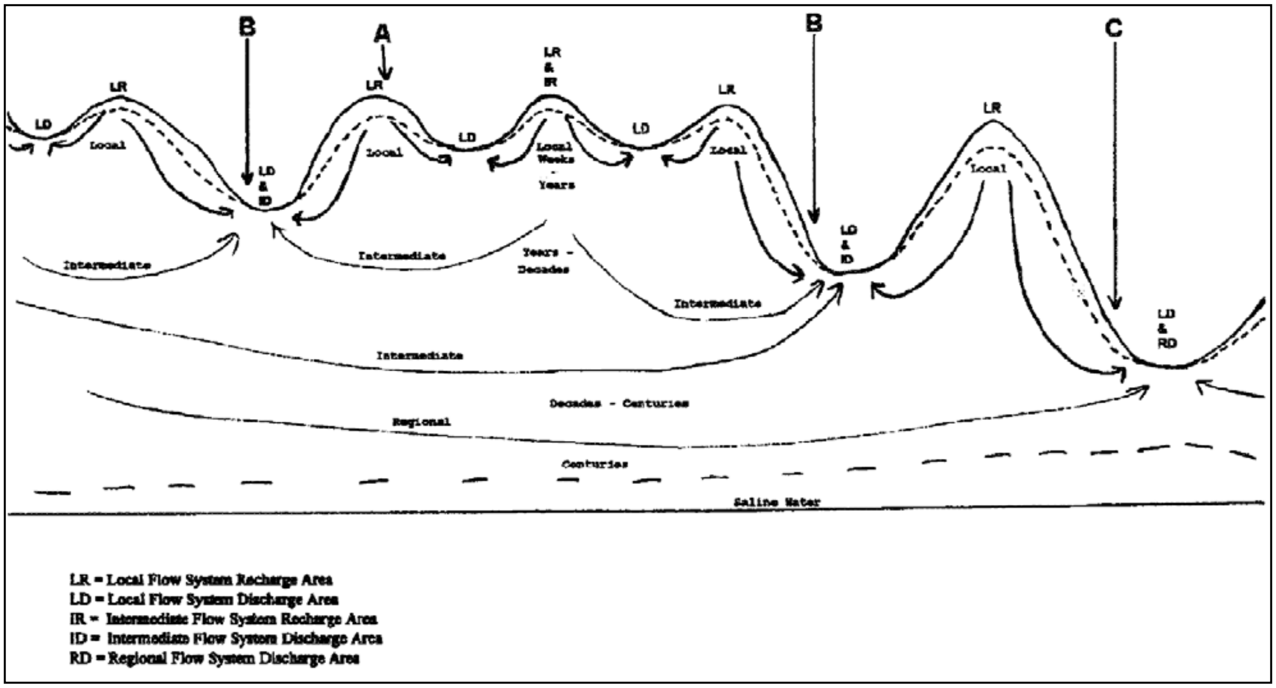

Figure 20: Sketch of Composite Groundwater Flow System[77]

[77] Callaghan, Fleeger, Barnes and Dalberto, "Groundwater Flow On The Appalachian Plateau of Pennsylvania", 1998.

6.3 Data Sources

For the Pittsburgh Seam analysis, a basic model was created that included state boundary data, topographic data, permit boundaries for longwall mining operations, and coal seam thickness. In assessing longwall mineable areas and overburden thicknesses, additional data were acquired for coal seam thicknesses and overburden thicknesses. A list of data utilized in this analysis is below.

- Pittsburgh Seam data are from the U.S. Geological Survey (USGS) Professional Paper 1625-C. http://pubs.usgs.gov/pp/p1625c/

- The National Elevation Dataset (NED) for Pennsylvania, West Virginia and Ohio is from the USGS. http://ned.usgs.gov/#

- State boundaries for Ohio, Pennsylvania and West Virginia are from the National Atlas. http://www.nationalatlas.gov/

- Longwall mine boundaries in the Pittsburgh seam originated from the Pennsylvania Spatial Data Access (PASDA) website. http://www.pasda.psu.edu/

- The Ohio mine boundaries were digitized from published mine maps found online. These maps originated from the Casey Run Task Force Alternate Impoundment Site Report, dated September 10, 2009 and are available through the Sierra Club website, who acquired them through an open records request. http://www.sierraclub.org/coal/oh/resources/ohio_valley_coal.aspx

- The Pennsylvania permit boundaries were downloaded from data titled “Active Underground Permit Boundaries” published by the Pennsylvania Department of Environmental Protection, Bureau of Mining and Reclamation in January 2012. http://www.pasda.psu.edu/uci/MetadataDisplay.aspx?entry=PASDA&file=UndergroundMiningPermit2012_01.xml&dataset=259

- The West Virginia permit boundaries were downloaded from the Department of Environmental Protection, Division of Mining and Reclamation Data. The data, titled “Underground Mining Limits,” are updated daily. The download date was Thursday, March 22, 2012. http://gis.dep.wv.gov/data/omr.html

6.4 Analytical Approach

This assessment examined areas of longwall mineable coal in the Pittsburgh seam where overburden thickness is less than 400 feet[78] and where the resource may be affected by the proposed definition of material damage to the hydrologic balance outside the permit area. The remaining coal resource in the Pittsburgh seam was evaluated to assess this issue. Parameters were then created to define longwall

[78] EIS Appendix B describes the analysis which resulted in the 400-foot of overburden threshold.

mineable coal, and these parameters were applied to the total resource to determine the location and amount of longwall mineable resources in the Pittsburgh seam. Next, overburden thicknesses were overlaid to evaluate the extent of the longwall mineable resources where overburden thickness falls below 400 feet.

The first step in the analysis was to create a base geospatial model to show the location of the Pittsburgh seam and determine the total amount of remaining coal. The United States Geological Survey (USGS) defined the Pittsburgh resource area in Professional Paper 1625-C.[79] The Pittsburgh seam resource area extends from Pennsylvania into Ohio and West Virginia. The majority of the mineable resource in the Pittsburgh seam in Maryland has been mined and no longwall mines are currently operating or projected to operate in Maryland. Therefore, Maryland was excluded from this study. In order to determine the remaining resource, previously mined areas were removed. This was done by merging the USGS and the Pennsylvania Spatial Data Access data and then deleting the combined area from the resource area. This procedure created a boundary of the remaining Pittsburgh coal resource, which is the basis for this study.

A map of the resource area in the Pittsburgh seam, as defined by the above parameters, is shown in Figure 21. The map shows the outcrop of the Pittsburgh coal seam, the previously mined area, and the remaining coal resource.

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[79] USGS, "U.S. Geological Survey Professional Paper 1625-C 2000. Resource Assessment of Selected Coal Beds and Zones in the Northern and Central Appalachian Basin Coal Regions", 2000.

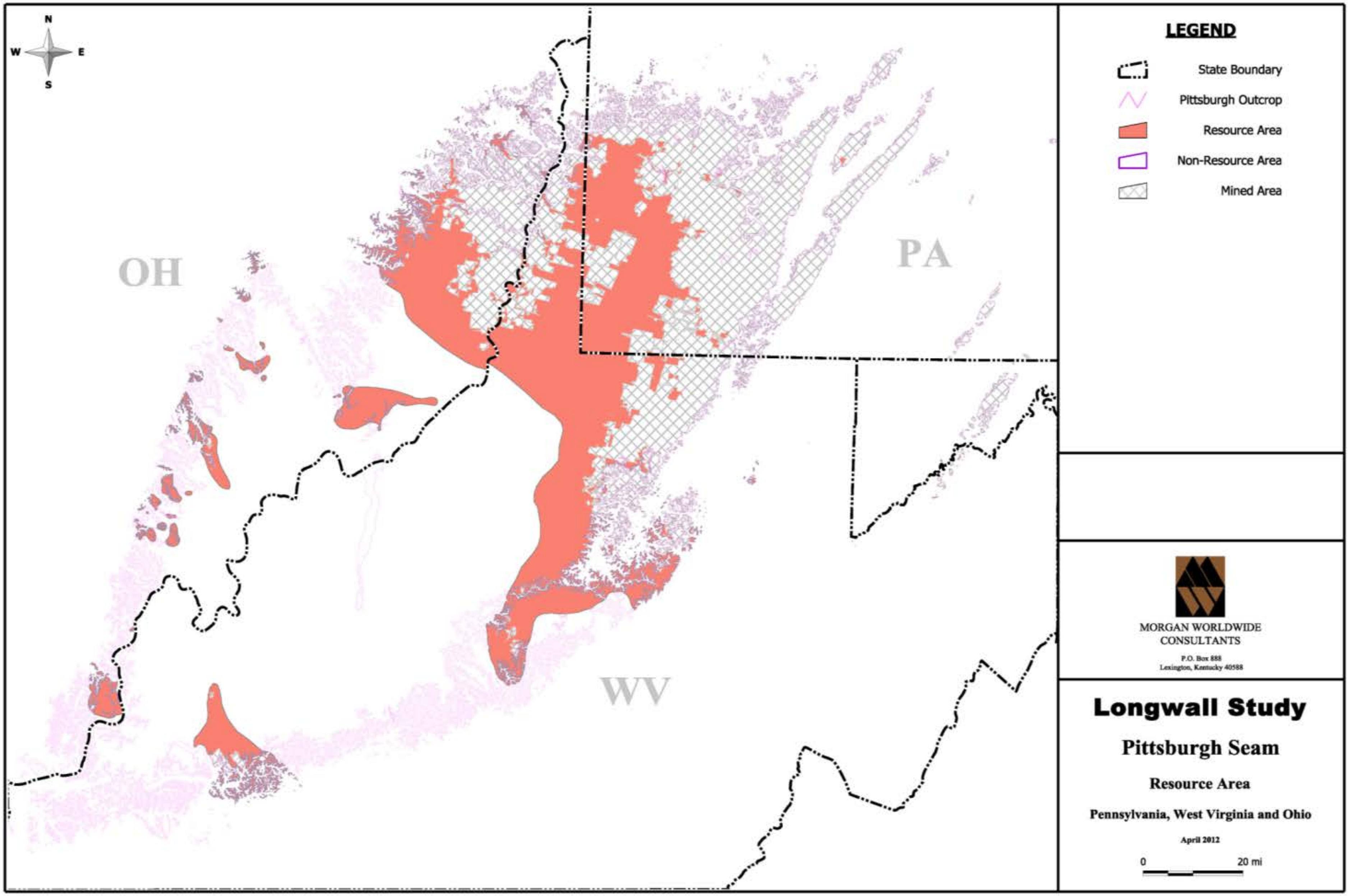

Figure 21: Pittsburgh Seam Resource Area

The next step in the analysis was to determine the portion of the resource area that is mineable by longwall methods. To define the longwall mineable area using the model, USGS data showing Pittsburgh coal seam height were used. Line data were re-contoured to create coal height areas ranging from about four to eleven feet. Initially, coal seam height was the sole variable used to define the longwall mineable portion of the resource. According to the February 2012 *Coal Age* "U.S. Longwall Census," which lists information for each longwall mining operation in the United States, including seam height, the lowest seam height mined in the Pittsburgh No. 8 seam was 60 inches, or 5 feet.[80] Additionally, the *SME Handbook* states that most longwall mining operations operate in seam heights ranging from 1.75 to 3.75 meters (5.74 to 12.3 feet thick).[81] Based on this information, the longwall mineable area in the Pittsburgh seam was originally defined as areas with a seam height of 5 feet or greater.

However, in order to check the assumptions described above, current and proposed longwall permit boundaries were placed over the resource area as defined by the 5-foot seam height. As shown in Figure 22, while the majority of the permit boundaries in West Virginia and Pennsylvania fell within the previously defined area, many of the permit boundaries in Ohio were located in areas where coal seam heights were less than 5 feet.

As a result, the resource area was expanded to include seam heights between 4 and 5 feet. The expanded resource area and overlying permit boundaries are shown in Figure 23.

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[80] Fiscor, Steve, "U.S. Longwall Census," Coal Age February 2012: 24.
[81] Darling, Peter, *SME Mining Engineering Handbook*, 3rd edition 1400, 2011.

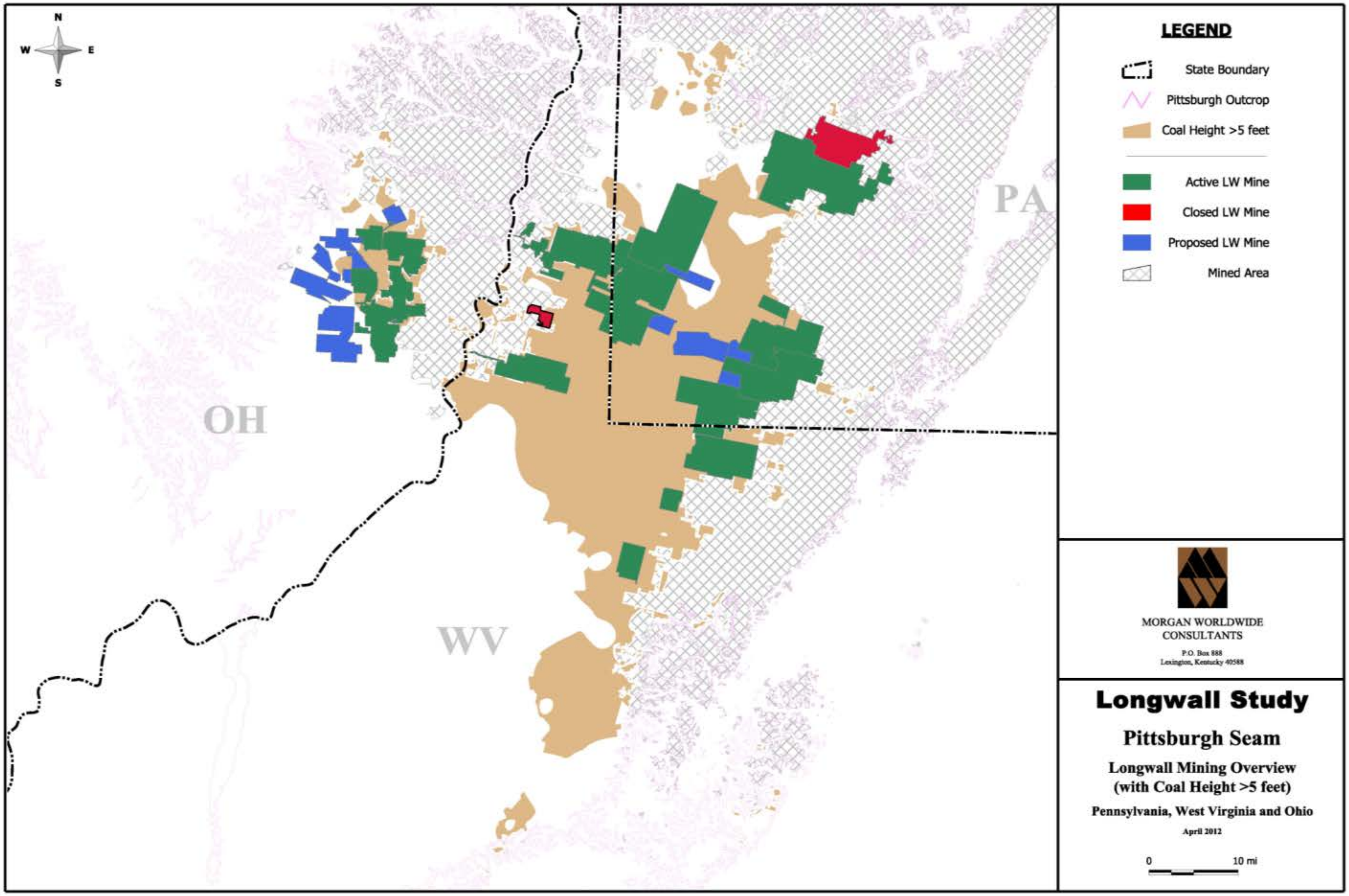

Figure 22: 5-Foot Coal Seam Thickness in Relation to Longwall Mining Permits

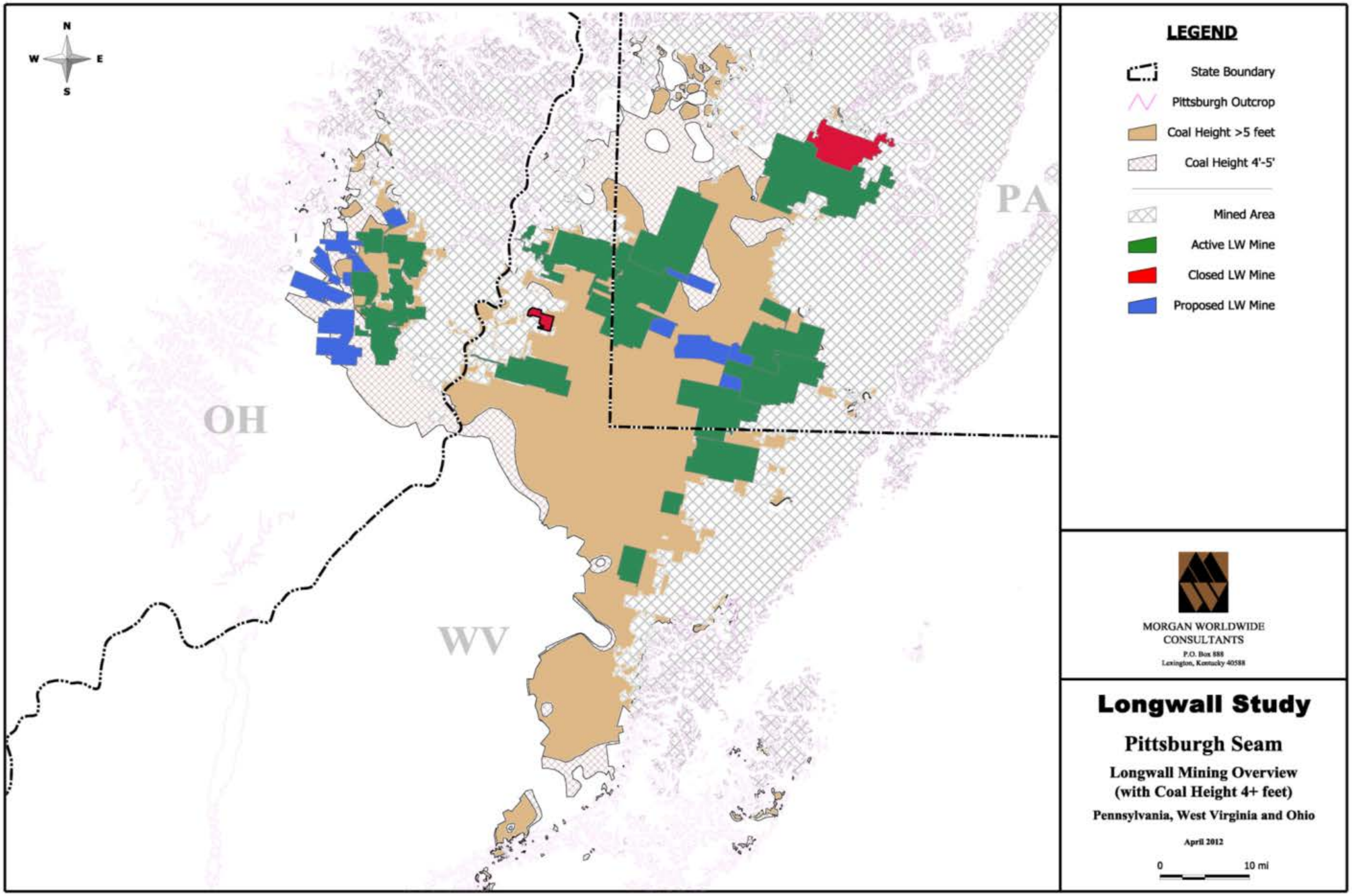

Figure 23: 4-Foot Coal Seam Thickness in Relation to Longwall Mining Permits

After defining the longwall mineable coal resource area, the next step in the analysis was to determine the overburden thicknesses within this area. From these areas, another surface was created by the triangulation method and average coal heights were queried. The average coal heights were used to define the longwall minable coal (four feet or more in height). After defining areas with coal heights of four feet or more, the overburden depths above these areas were determined.

To model where longwall mines operating in the Pittsburgh seam may have increased risk of causing material damage to the hydrologic balance outside the permit area, overburden thickness data were acquired from the National Elevation Dataset (NED). The NED is the primary elevation data product published by the USGS. The elevation data are derived from varied sources and converted into a single projection and coordinate system. The surface defined by the USGS NED was subtracted from the Pittsburgh seam surface to create an overburden thickness surface.

After defining the study area, including the coal seam thicknesses and depth of overburden, the next step was to determine where overburden depths were less than the 400-foot threshold. As described in Appendix B and above, results from a literature review indicated that permanent stream loss due to longwall mining in the Pittsburgh seam is a concern at cover depths less than 400 feet. While site specific conditions at some operations would allow for longwall mining at depths less than 400 feet without a risk of MDHB, this study uses overburden thickness as the chief predictor of the likelihood that permanent stream loss will occur as a consequence of longwall mining. Where overburden depths were less than 400 feet, it was assumed that these areas would be mined using room and pillar methods.[82] In application, however, based on more detailed site specific analysis, it may be feasible to longwall mine at depths less than 400 feet without causing material damage to the hydrologic balance outside the permit area and some operations in Northern Appalachia, such as Enlow Fork in Pennsylvania, have been permitted at shallower depths and not resulted in impacts.

The overburden thicknesses were divided into three ranges (0-400 feet, 400-600 feet, and 600+ feet). Areas were color coded based upon a range of overburden thickness. Figure 24 shows the area where longwall mineable coal resources exists in the Pittsburgh seam based upon the defined resource area, mined out area, coal seam thickness, and the range of overburden in each area.

[82] Although it is recognized that subsidence can occur with room and pillar operations, as noted previously in this document, subsidence caused by room and pillar operations would not be expected to result in permanent stream dewatering. Because room and pillar operations are more flexible, the mine plan can be modified to ensure that a greater degree of roof support is in place below streams. In addition, in some cases it would be uneconomical due to the difference in recovery factors for room and pillar mining to replace a longwall operation, especially for longwall mines that are large in scale.

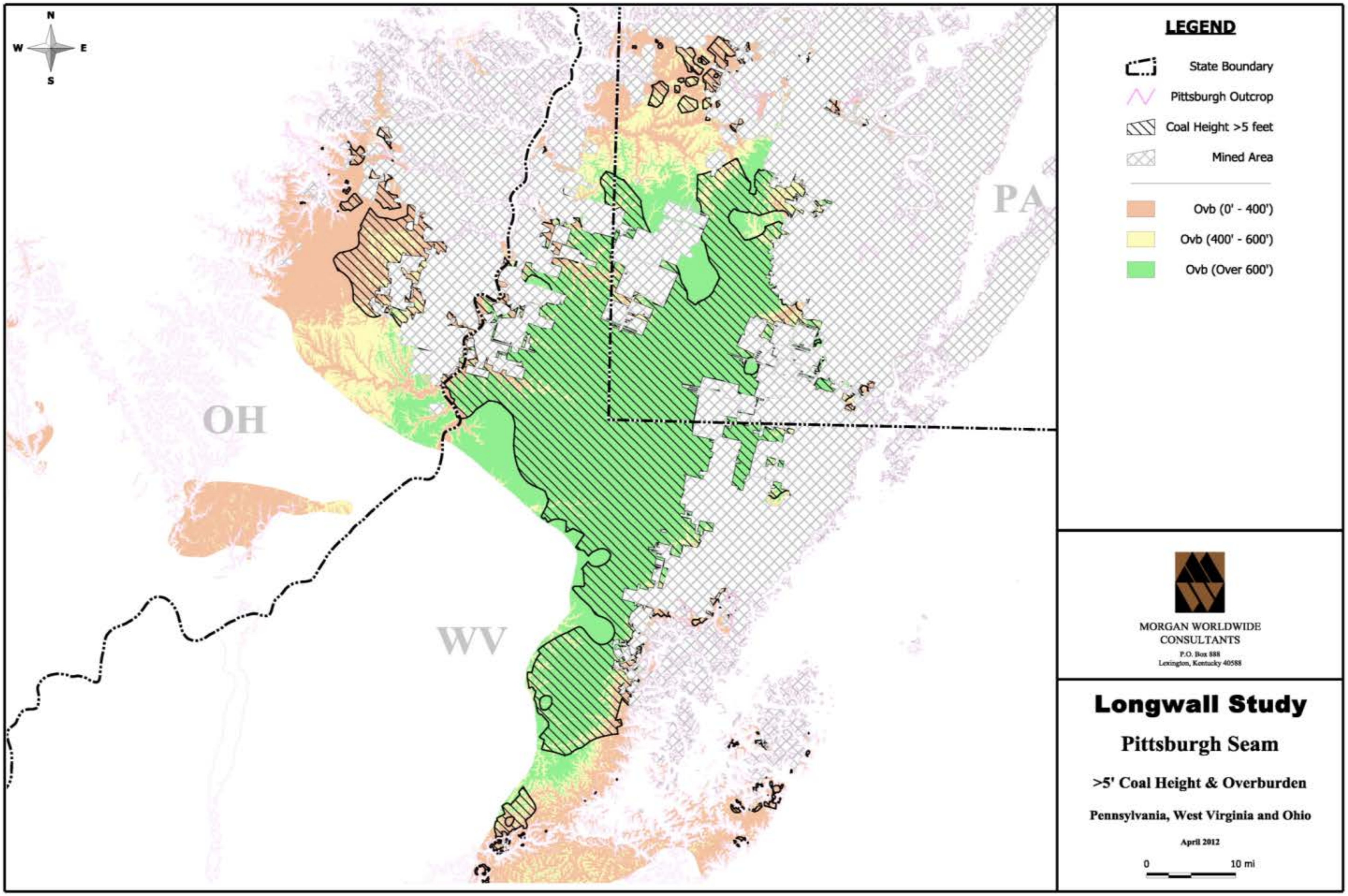

Figure 24: Coal Seam Height in Relation to Overburden Thickness

6.5 Assumptions and Limitations of this Analysis

The methodology employed in this analysis of the Pittsburgh Seam is based on the following key assumptions:

- The definition of "material damage to the hydrologic balance outside the permit area" is interpreted the same way for baseline and all action alternatives, although some alternatives are the same as baseline;
- Longwall mining induced subsidence that causes permanent stream loss is MDHB;
- Longwall mineable reserves are defined as coal with a seam height of four feet or greater;[83]
- Where overburden thickness is less than 400 feet, coal could be mined by room and pillar methods (with limited extraction rates) to avoid causing permanent stream loss and thus, MDHB[84]; and
- Since stream data and locations were not incorporated into this assessment, the potential for MDHB is dependent solely on the threshold overburden thickness, regardless of whether a stream is present above the mining operation.

Some of the limitations listed below are also included in Section 2.5. These restrictions include:

- This analysis did not define or consider coal resources that are unmineable because of technological, economic, environmental, legal, or other factors;
- Resource related information presented in Section 6.6 of this document should be considered as macro-level approximations and are intended only for the use of this report. Refer to the U.S. Geologic Survey or other applicable sources for published resource estimates;
- Longwall mining occurs in other coal seams in West Virginia, but these were not considered in this analysis;
- Water quality issues at underground mining operations could cause MDHB regardless of whether the operation results in subsidence. Individual longwall mining operations can result in material damage to the hydrologic balance outside the permit area where overburden depth is greater than 400 feet or could not result in MDHB where overburden depth is less than 400 feet, depending on site-specific variables;

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[83] A 4-foot seam height was used to define longwall mineable reserves, however, in practice, based on site specific conditions, operators may mine coal seams less than 4 feet thick using the longwall method.

[84] Note that in some cases the regulatory authority would permit longwall mining operations at depths of less than 400 feet if an assessment of the geology, streams, and other relevant factors show no danger of causing MDHB. All mines are assessed during the mine permitting process individually on a case-by-case, site specific, basis as to their MDHB potential.

- The analysis assumes that any area where overburden was less than 400 feet thick would cause material damage to the hydrologic balance outside the permit area, regardless of whether a stream was located in that area, resulting in overestimation of areas that would only be mineable by room and pillar methods; and

- This analysis could not determine the extent to which subsidence associated with room and pillar operations could result in permanent stream loss. Subsidence associated with room and pillar mining is typically a localized event, can over a decade following the closure of the mining operations, and requires a site-specific analysis to determine the degree of impacts and whether permanent stream loss could occur.

6.6 Results

This section presents the anticipated impact of the proposed definition of MDHB, in terms of permanent stream loss, on longwall mining in Northern Appalachia. The section first assesses the extent of the total longwall mineable resource in the Pittsburgh seam based on a 4-foot coal height and incorporating overburden depth. Next, the coal resources and overburden thicknesses are assessed on a state-by-state basis. As a check on the analysis, currently operating longwall mining permits were layered on top of the map showing the 4-foot coal seam height and layers where overburden thickness was greater than 400 feet to determine whether currently operating or proposed future permits were in line with the assumptions relied upon in this analysis.

6.6.1 Resource Where Overburden Depth is Less than 400 Feet

Based upon coal seam height data and using a minimum 4-foot seam height for longwall mineable coal resources, a total of 10.5 billion tons of mineable coal were calculated to exist in the Pittsburgh seam.[85] See Figure 25.

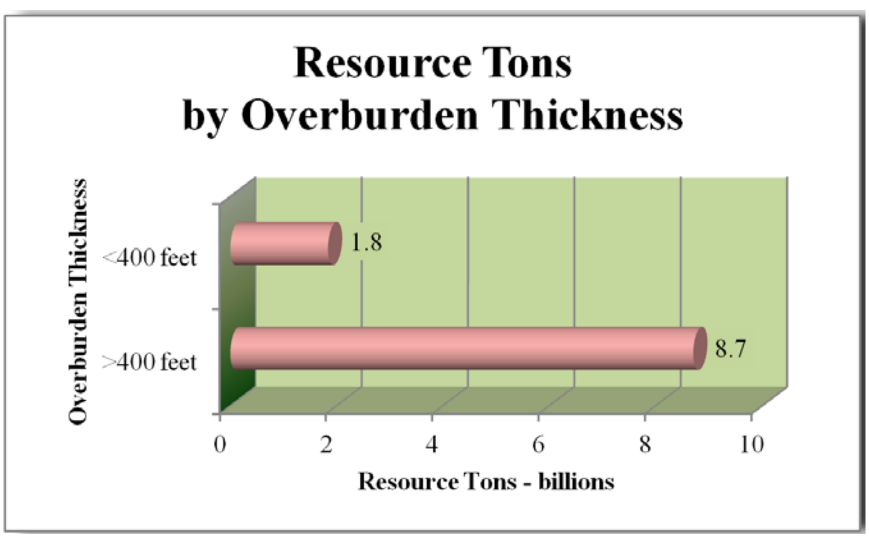

Figure 25: Pittsburgh Seam Resource Tons by Overburden Thickness (billions of short tons)

[85] This calculation total does not assess whether this resource is economically mineable or would otherwise be unmineable due to legal, environmental, social, or other restrictions.

Of this resource, approximately 8.7 billion tons, or 83 percent of the total longwall mineable reserve in the Pittsburgh seam, are located where overburden thickness is greater than 400 feet and thus is assumed to be mineable by longwall methods. Coal seams with less than 400 feet of overburden could still be mineable by room and pillar methods, and in some cases longwall methods, depending on a site specific analysis, assuming no additional constraints or restrictions.

While approximately 83 percent of the total resource is located at depths greater than the 400-foot overburden thickness threshold, a breakdown of the resources and overburden thickness by state shows that 61 percent of the resources in Ohio are located at depths shallower than 400 feet. In contrast, only about 12 percent and 9 percent of the resources in Pennsylvania and West Virginia, respectively, are located in areas where overburden is less than 400 feet thick.[86] Table 20 lists the in-situ coal resources at each range of overburden depth by state.

Overburden Thickness	OH	PA	WV	Total
0'-400'	0.9	0.4	0.5	1.8
400'-600'	0.4	0.6	0.6	1.7
>600'	0.1	2.4	4.6	7.0
Total	1.4	3.4	5.7	**10.5**

Table 20: Coal Resource Tonnage by Overburden Depth and State (billions of short tons)

[86] While it is recognized that underground mining typically does not occur at depths less than 100 feet due to safety considerations, poor coal quality, and the potential for catastrophic subsidence, coal between 0-100 feet was considered in the analysis since coal at these depths had previously been mined in some areas due to easy accessibility at the outcrop. Additionally, the geospatial analysis showed that currently permitted longwall mining operations encompassed some areas where overburden was less than 100 feet. Therefore, coal seams with overburden of less than 100 feet thick were included as part of the coal resource in this analysis, however, the amount of coal at depths between 0-100 feet makes up a very small percentage of the coal resource in all states.

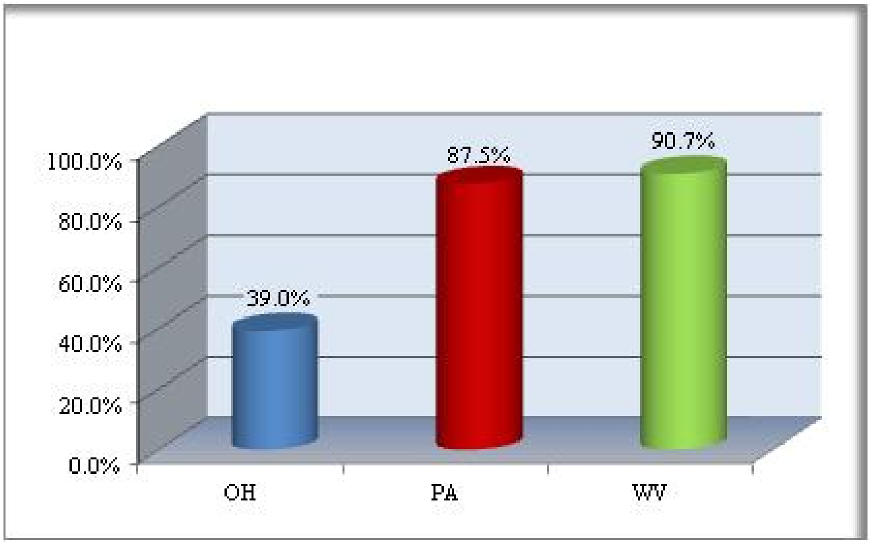

Figure 26: Percent of Resources with Greater than 400 Feet of Overburden by State

To further assess potential impacts on a state-by-state basis, the percentage of the resource in each state located in the three overburden thickness categories (0-400 feet, 400-600 feet, and 600+ feet) was calculated (Figure 26).

As shown in Figure 27, the vast majority of resources in West Virginia (approximately 80 percent) are located at depths greater than 600 feet, indicating that most of these resources can be mined by the longwall method with little risk of causing permanent stream loss absent any extenuating factors. Similarly, in Pennsylvania, approximately 69 percent of the coal resource is located at depths greater than 600 feet, with an additional 19 percent of the resource located at depths between 400 and 600 feet. However, in Ohio, 61 percent of the resource is located at depths with less than 400 feet of cover, with only 8 percent of the resource located at depths greater than 600 feet.

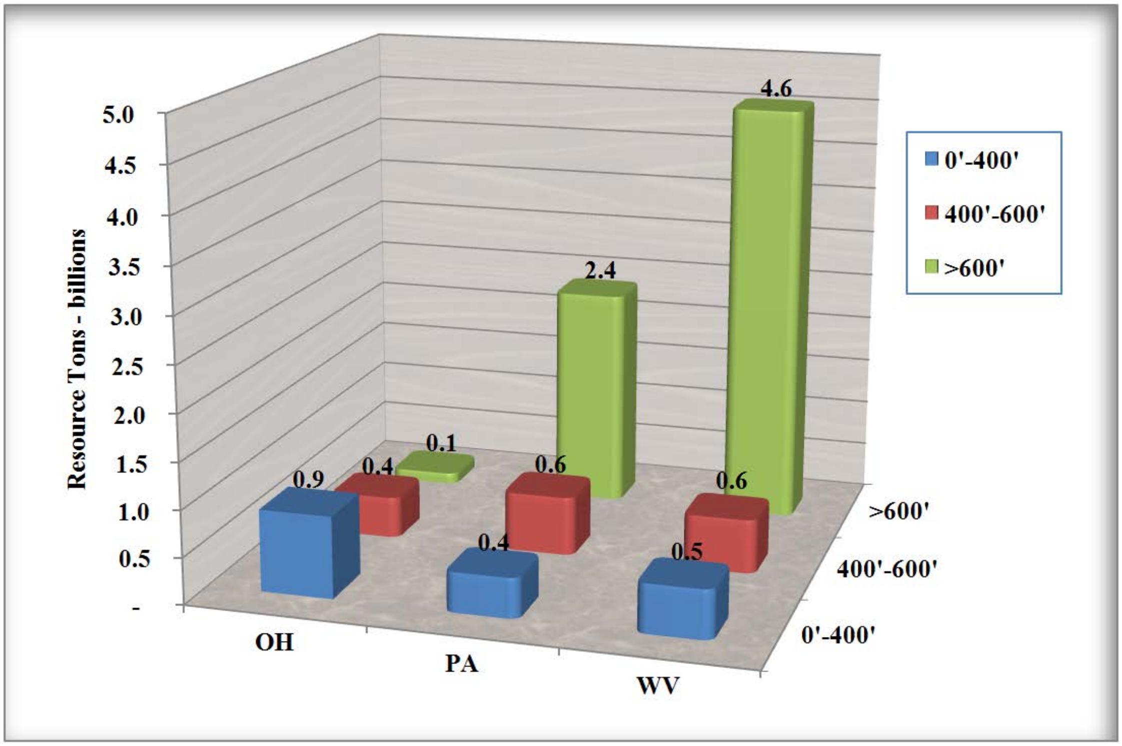

Figure 27: Overburden Thickness and Coal Tonnage by State (billions of short tons)

Pittsburgh seam longwall mine production and future projections were then assessed to compare potential future production to the remaining resource considered to be longwall mineable (areas with greater than 400 feet of overburden). Initially, the resource was divided into longwall mineable coal and coal that may not be longwall mined based on the 400-foot overburden threshold. After calculating the tonnage of longwall mineable coal, a conservative 65 percent recovery factor was applied to estimate the amount of longwall resources.[87] Next, past production data and future production projections for each longwall mine, operating in the Pittsburgh seam, were assessed. Table 21 tabulates the recoverable longwall resources by state.

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[87] Although the longwall recovery rate is typically closer to 85%, resulting in more coal recovery than room and pillar mining, a conservative 65% factor was used since mineability factors such as environmental constraints and legal requirements (*see, e.g.,* 30 U.S.C. 1272) for locating mining operations were not evaluated as part of this analysis.

	Pennsylvania	West Virginia	Ohio
Resources with **Less than** 400 Feet Overburden (Room and Pillar mining only)	0.4	0.5	0.9
Resources with **Greater than** 400 Feet Overburden (longwall Mineable)	3.0	5.2	0.5
Recoverable Resources with Greater than 400 feet Overburden (65% recovery factor)	2.0	3.4	0.3

Table 21: Assessment of Coal Resources and Longwall Production by State (billions of short tons)

Pittsburgh seam longwall mining production and projected production is shown by mine in Figure 28. As shown, while longwall coal production on the Pittsburgh seam has fluctuated in recent years, production and associated projections show a steady increase in production since 2009.

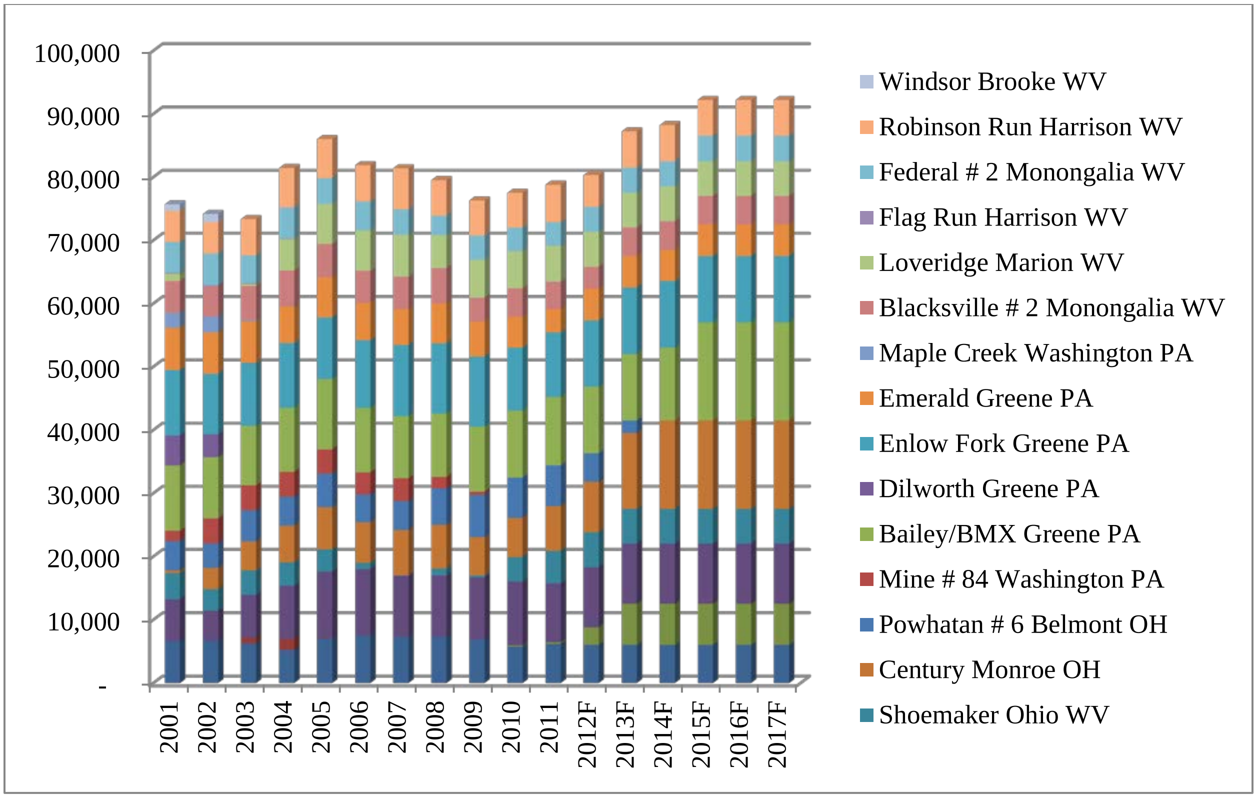


Figure 28: Longwall Mining Production and Projections in Northern Appalachia, Pittsburgh Seam (thousands of short tons)[88]

While it is impossible to predict future Pittsburgh seam production for the life of the estimated longwall mineable resources, including the introduction of new mines, various production scenarios were created to come up with a range of possible outcomes. The first scenario assumed an average production rate equal to the lowest production year since 2001 for each state. The second scenario assumed an average production from 2001 through the 2017 production projections for each state. The third scenario assumed an average production equal to the highest production year since 2001, including the production projections, for each state. Finally, the fourth scenario used a trend analysis to estimate future production increases beyond 2017. Pittsburgh seam longwall production by state is shown in Figure 29, while resource estimates based on the four scenarios above are shown in Table 22.

[88] Past production data derived from MSHA's Mine Data Retrieval System and compiled by Energy Ventures Analysis. Future production projections by Energy Ventures Analysis.

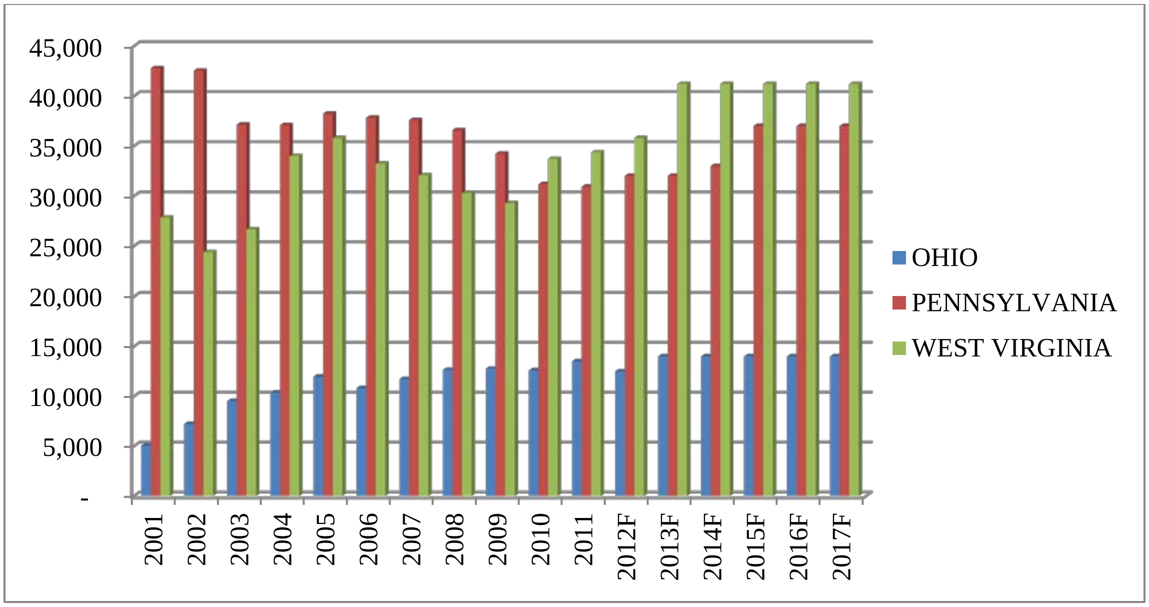


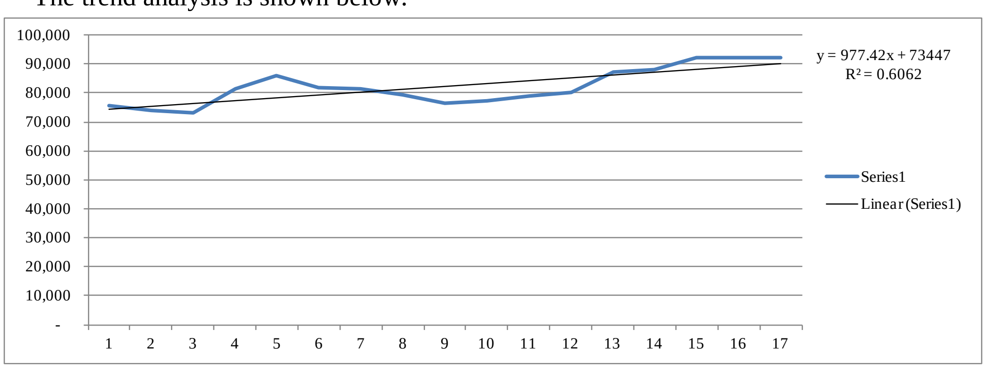
Figure 29: Pittsburgh Seam Longwall Production and Projected Production by State (thousands of short tons)

	Pennsylvania	West Virginia	Ohio
Scenario 1: Lowest Year (thousands of short tons)	31,000	24,000	5,000
Scenario 2: Average Year (thousands of short tons)	36,000	34,000	12,000
Scenario 3: Highest Year (thousands of short tons)	43,000	41,000	14,000
Scenario 4: Projected 2025 Production	100,000		

Table 22: Production Rates for Life of Reserve Scenarios (thousands of short tons)

As shown in Table 22 above, the lowest, average, and highest actual or projected longwall coal production from the Pittsburgh seam was acquired. In addition, a trend analysis was conducted to estimate the rate at which longwall coal production from the Pittsburgh seam was changing over time. The trend indicated that production was increasing by approximately 1 million tons per year.[89] Therefore, 1 million

[89] The trend analysis is shown below.



tons per year were added to the 2017 projections to approximate the amount of longwall coal production that could be expected to come from the Pittsburgh seam in 2025 based on the trend analysis. This total of 100 million tons was only 2 million tons more than the total of the highest projected production from each state (Scenario 3 in Table 22), which was 98 million tons. Because these totals were so close, life of resource estimates were only conducted for Scenarios 1-3.

Each of the three production scenarios was applied to the estimated longwall mineable coal to project the life of resource in each state. The estimated longwall mineable resources were taken from Table 22 and the three coal production scenarios were applied.

	Pennsylvania	West Virginia	Ohio
Longwall Recoverable Resource (billions of short tons)	2.0	3.4	0.3
Yearly Coal Production Scenario 1 (thousands of short tons)	31,000	24,000	5,000
Life of Resource - years (Scenario 1: Low Production)	63	142	60
Yearly Coal Production Scenario 2 (thousands of short tons)	36,000	34,000	12,000
Life of Resource - years (Scenario 2: Average Production)	54	100	25
Yearly Coal Production Scenario 3 (thousands of short tons)	43,000	41,000	14,000
Life of Resource - years (Scenario 3: High Production)	45	83	21

Table 23: Estimated Life of Pittsburgh Seam Longwall Resources under Three Scenarios

As shown in Table 23, even assuming a high production scenario, longwall mineable resources at depths greater than 400 feet are projected to last for about 20 years in Ohio, 45 years in Pennsylvania, and 80 years in West Virginia. In addition, these numbers do not take into account coal that could be mineable at depths less than 400 feet without causing MDHB or coal seams that may be thinner than the 4-foot seam height used in this analysis. As a result, these estimates would exclude additional coal that could be longwall mineable.

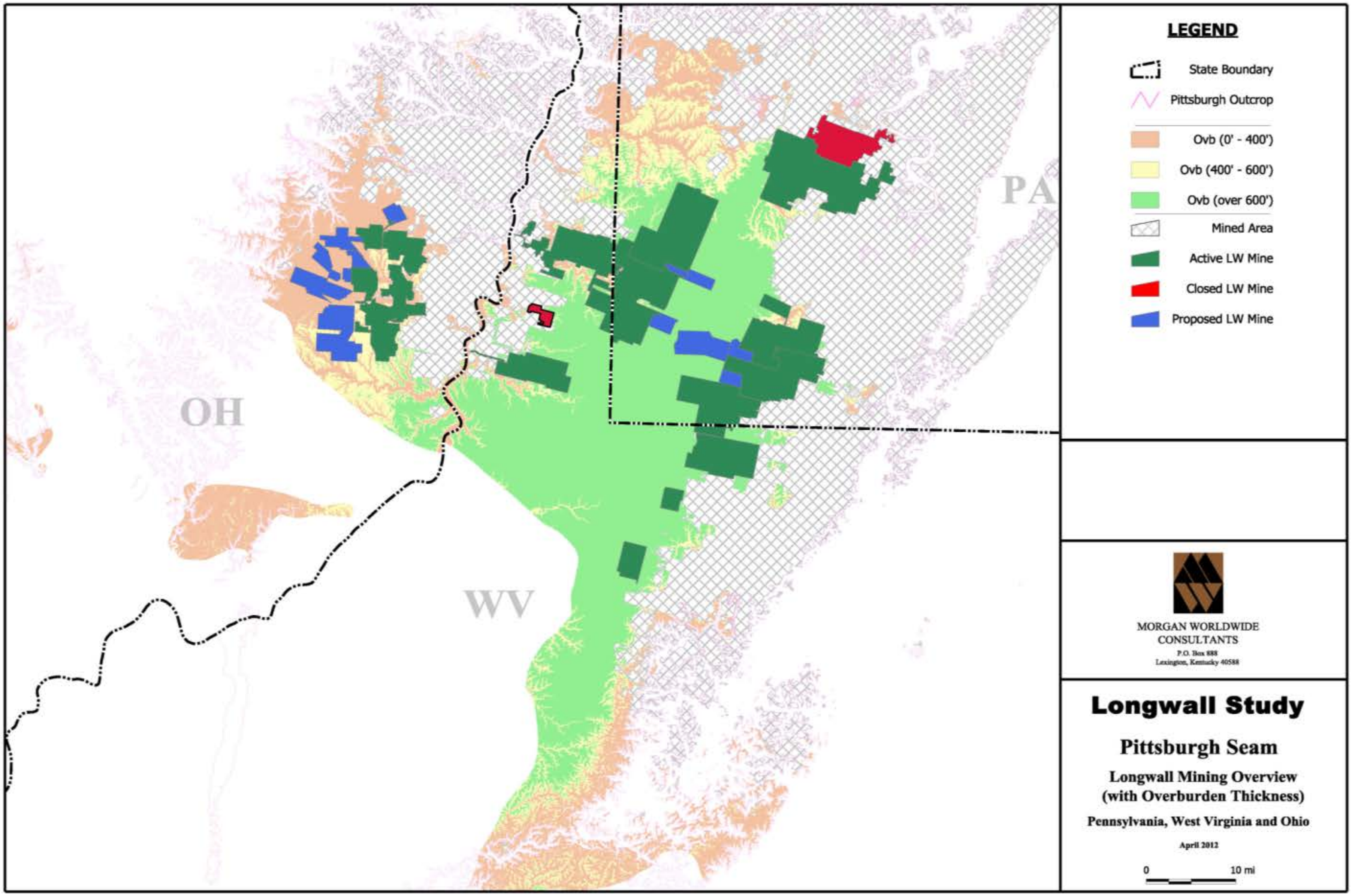


Figure 30: Longwall Mine Permit Boundaries in Relation to Overburden Thickness

6.6.2 Ohio Longwall Mining Practices and Conditions

After determining the resources that could potentially be affected by the material damage element in each state, the analysis was cross checked with actual permit data. GIS data of the locations of past, current, and proposed longwall mining permits in the Pittsburgh seam area were acquired in order to determine the relationship between currently operating permits and the results of the spatial analysis. The goal of comparing permit locations to the spatial data was to determine if the 400-foot overburden depth threshold to define longwall mineable resources was consistent with current mining operations. Figure 30 shows the three overburden thickness ranges along with active, closed, and proposed longwall mining operations in the region.

As shown in Figure 27, the majority of the Pittsburgh seam resources in Pennsylvania and West Virginia lie within areas where the overburden depth is greater than 400 feet. However, in Ohio, many of the current and proposed mining operations are located in areas where overburden thickness is less than 400 feet.

Because of the inconsistencies between the parameters used to define overburden depth for this analysis and the actual overburden depths above currently operating and proposed permits in Ohio, an assessment of Ohio longwall mine permit data was conducted to determine the reasons for these inconsistencies. Permit data was acquired for the two currently operating longwall mining operations in eastern Ohio to assess the depths at which longwall mining occurred. The shallowest depth at which longwall mining occurred in these cases was about 200 feet, which is much less than the 400 feet of overburden that was analyzed. In reviewing the probable hydrologic consequences section of the permit applications, it appears that experiences from past mining in the area indicate that for areas where there is 200 feet or more of cover, any reductions in stream flow occur mostly in the headwaters of the stream and that a majority of streams that were undermined returned to normal flow conditions within several years after mining.

Additionally, the overburden lithology in Ohio may allow for longwall mining at shallower depths. Permit data indicates that shale and clay stone units overlie the coal seams, which may inhibit the downward migration of groundwater. According to the permit data, the clay stone beds will not fracture without significant strain and are relatively impermeable. The permit application indicated that the clay stone beds provide an adequate barrier against inflow from surface water and shallow groundwater disruptions caused by longwall mining. Thus, according to Ohio permitting data, material damage to the hydrologic balance outside the permit area would be expected to occur at depths less than 200 feet, might occur between 200-400 feet depending on site specific variables, and would likely not occur at depths greater than 400 feet.

The geologic formation where these clay beds generally reside is referred to as the Upper Pennsylvanian Monongahela Group. The Upper Pennsylvanian Monongahela Group is situated in the Northern Appalachian Basin in Ohio, West Virginia, Pennsylvania, and Maryland. It extends over more than

11,000 sq. mi and ranges in thickness from 200 feet, in western Ohio, to 430 feet in north-central West Virginia (EPA, 2004, and references therein).[90]

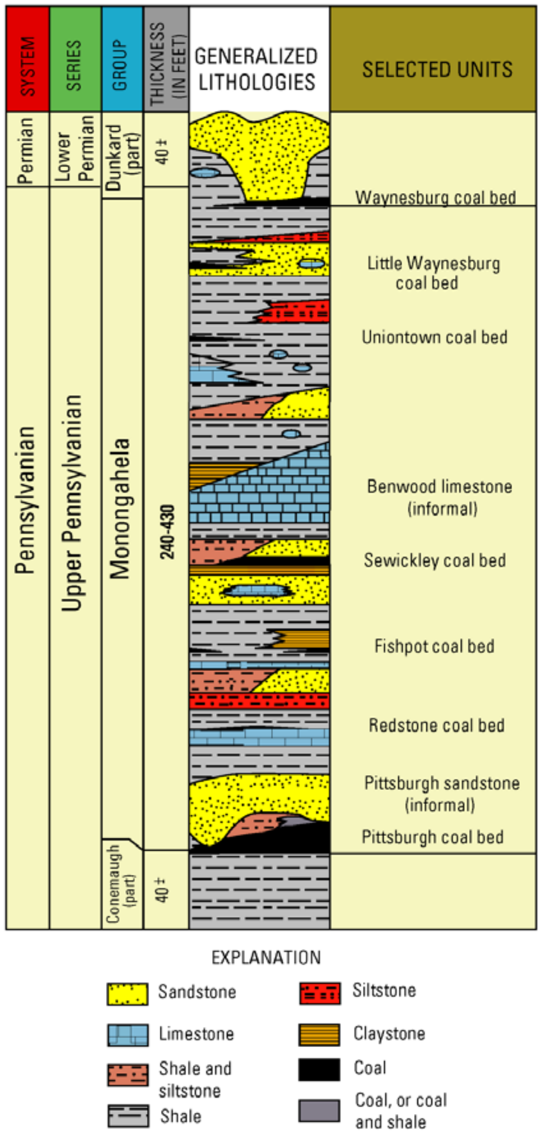


Figure 31: Generalized stratigraphic column of the Upper Pennsylvanian Monongahela Group showing major coal beds. (Tewalt, et al., 2000)

The Monongahela Group comprises the Pittsburgh Formation and the Uniontown Formation (www.geology2.pitt.edu, and references therein). See Figure 31. The Pittsburgh coal bed, of the Pittsburgh Formation, forms the basal unit of the group with overlying, interbedded coal and sedimentary deposits of the Pittsburgh and Uniontown Formations extending up to the base of the Waynesburg coal bed, of the Permian Dunkard Group. The deposits were later uplifted and partially eroded during the regional Allegheny Orogeny (Tewalt, et al., and references therein).

The Pittsburgh coal bed, and other Pennsylvania and Permian coal beds of this region, were derived from peat deposits and were interbedded with sediments within a regional foreland basin (Tewalt, et al., and references therein). The Monongahela beds were laid down in predominantly swamp and lacustrine (lake) environments. The clastic sedimentary deposits of the Monongahela Group include sandstone, siltstone, shale, mudstone, claystone, and limestone. These are freshwater deposits, laid down in extensive, shallow lakes and mudflats of the region (EPA, 2004; www.geology2.pitt.edu, and references therein).

In a 1995 study by R. J. Matetic in Vinton County, Ohio, the overburden above an active longwall panel consisted of 30% sandstone, 30% shale, 30% claystone, and 10% coal. The study indicated that the

[90] Tewalt, S. J., Ruppert, L. F., Bragg, L. J., Carlton, R. W., Brezinski, D. K., Wallack, R. N., and Butler, D. T., "Chapter C – A digital resource model of the Upper Pennsylvanian Pittsburgh coal bed, Monongahela Group, northern Appalachian Basin coal region, in Northern and Central Appalachian Basin Coal Regions", 2000 resource assessment of selected coal beds and zones in the northern and central Appalachian Basin coal regions: U. S. Geological Survey Professional Paper 1625-C", CD-ROM, version 1.0, 2001.

geology found at this site was typical of that found in southeastern Ohio. See Figure 32. Overburden thickness for the longwall panels analyzed in this study ranged from 214 feet to 280 feet.[91]

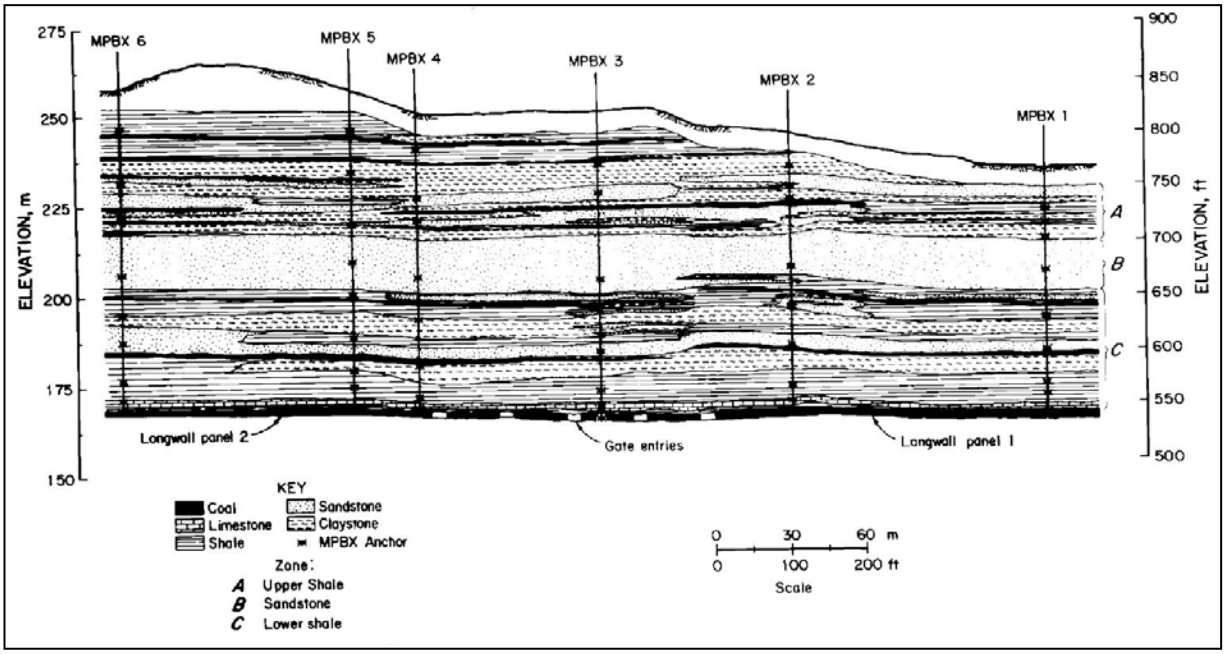


Figure 32: Generalized Cross-Section of Vinton County Study Area

In summary, coalfields in southeastern Ohio appear to have significant shale and claystone in the overburden above the Pittsburgh seam. Where overburden is dominated by claystone and shale, which typically have relatively high plasticity, longwall mines can potentially operate at shallower depths without causing permanent stream loss. Ideally, these beds should be near the surface where groundwater can readily recover and continue feeding the streams. The Ohio longwall mines may not be as susceptible to permanent stream loss compared with other areas in the Northern Appalachian Region, where strata with low plasticity (i.e. sandstone) are markedly present in the overburden.

In places where claystone and shale are not present in sufficient thicknesses in the overburden, longwall mining may not be feasible. In these cases, room and pillar mining, with well-designed coal pillars, may be the best means to extract the coal. However, secondary room and pillar mining may not be feasible at these shallower overburden depths.

Figure 33 and Figure 34 show a more complete breakdown of the coal resources in Ohio by overburden depth. Approximately 15 percent of the coal resource in Ohio or about 0.3 billion short tons is located in areas where overburden thickness is less than 200 feet thick and about 0.6 billion short tons is located in areas where overburden thickness is less than 300 feet thick. See also Table 24.

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[91] Matetic, R.J, et al., "Modeling the Effects of Longwall Mining on the Ground Water System", 1995.

Ovb Thickness	Tons	% of Total
<100	0.1	3.6%
100 - 200	0.2	11.3%
200 - 300	0.3	23.9%
300 - 350	0.2	11.6%
350 - 400	0.2	10.6%
+400	0.6	39.0%
Total	**1.4**	**100.0%**

Table 24: Ohio Resource Tons by Overburden Thickness (billions of short tons)

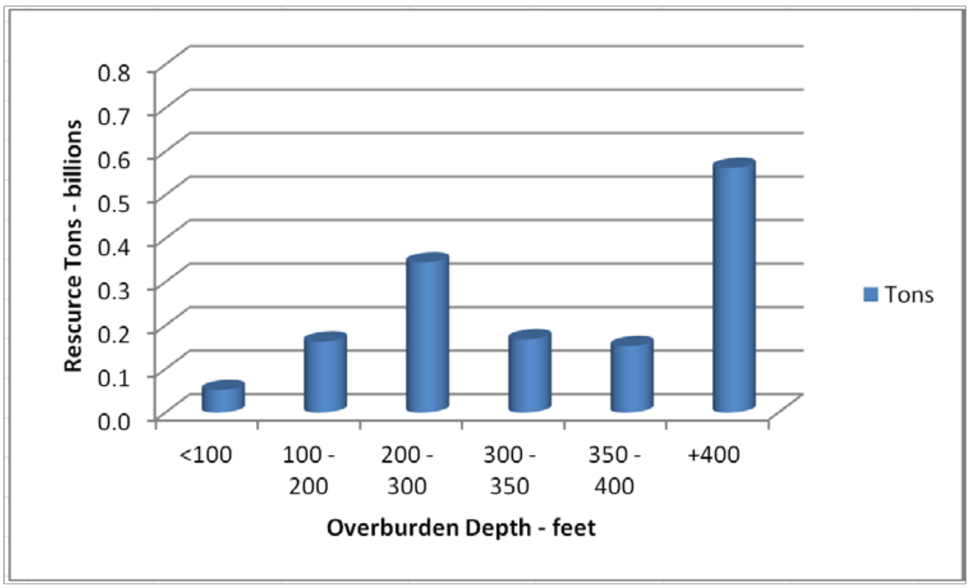

Figure 33: Ohio Resource Tons by Overburden Thickness (billions of short tons)

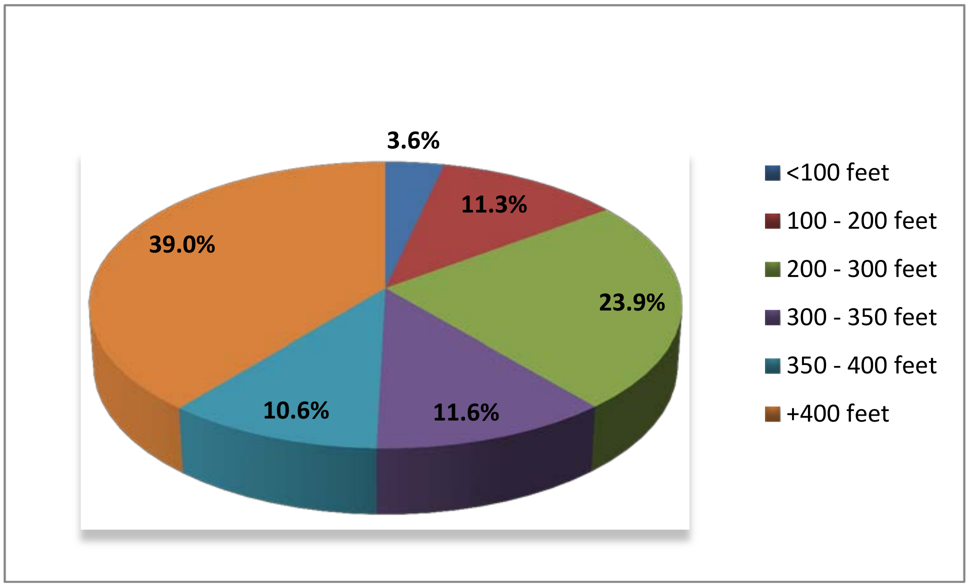

Figure 34: Percentage of Ohio Coal Tons by Overburden Thickness

7. CONCLUSIONS

To address the potential impacts of a national MDHB definition, this report examined longwall coal resources on a regional level. Coal regions were categorized as major or minor producers of longwall coal based on recent coal production. At about 150 million tons produced in 2012, longwall production from the Northern Appalachia, Illinois Basin, and Colorado Plateau regions represent about 77 percent of the tons produced in the United States by this mining method[92]. Therefore, these three regions were categorized as major longwall producing regions and were given greater consideration in this report. Minor coal regions include Central Appalachia, Southern Appalachia, and Northern Rocky Mountains.

After evaluating various parameters, threshold overburden depth (defined as the vertical distance measured from the top of the coal seam to the surface) was adopted for a regional analysis of Northern Appalachia, Illinois Basin, and the Colorado Plateau. If necessary, a subsequent evaluation of regional lithology was also conducted. Other factors affecting possible stream loss from subsidence are varied and include mine configuration, extraction rate, local lithology, drainage area, previous mining, topography, and local and regional aquifer characteristics. However, these factors are site-specific and cannot be incorporated into a regional assessment of the potential effects of longwall mining.

The designated threshold overburden depths for the three major longwall producing regions are listed below.

- Northern Appalachia 400 feet
- Illinois Basin 200 feet
- Colorado Plateau 500 feet

[92] U.S. Energy Information Administration (EIA)

For the purpose of this report, MBHD is defined as permanent stream loss. Findings for the major coal regions are summarized below.

Northern Appalachia

For the Pittsburgh Seam in Northern Appalachia, the analysis indicates that if only coal resources with 400 feet or more of overburden are deemed recoverable by the longwall mining method, decades of coal production remain in West Virginia, Pennsylvania, and Ohio, even at relatively high extraction rates.

In Ohio, longwall mining may occur without causing permanent stream loss at overburden depths between 200 and 400 feet. This aberration may be due to the presence of shale and claystone in the overburden above the Pittsburgh seam. Claystone and shale strata, which typically have relatively high plasticity, may allow longwall mines to operate at shallower depths without causing permanent stream loss.

Illinois Basin

An assessment of the Illinois Basin coal region was made after reviewing the permit application packages from the state regulatory authorities, OSM oversight of the regulatory authority, and available literature. This information indicated that longwall mining can generally not occur in the Illinois Basin at threshold overburden depths shallower than 200 feet. Due to the geology in this region, MDHB would not be expected take place where threshold overburden depths are greater than 200 feet.

Colorado Plateau

A regional assessment of longwall mining in the Colorado Plateau revealed that MDHB due to permanent stream loss was typically not a concern at depths greater than 500 feet.

Findings for the minor coal regions are summarized below.

Central Appalachia

A 400-foot overburden threshold depth was proposed for the Appalachian Basin. Most other overburden depths for the Justice No. 1 mine in Boone County, West Virginia are well over the 400 foot threshold . The minium overburden depth for the Alma No. 1 mine is about 440 feet. The Pinnacle and American Eagle mines both operate above 600 feet of overburden.

Southern Appalachia

In Alabama of the Southern Appalachian coal region, longwall mining typically occurs at depths greater than 1,000 feet. Based on the overburden thickness and historic mining in this region, MDHB, as defined by permanent stream loss, does not appear to have a high potential for occurrence.

Rocky Mountains

Three longwall mines are currently operating in this region: Bull Mountains in Montana, Bridger Underground in Wyoming, and the Foidel Creek mine in Northwestern Colorado. Production from these three mines totaled about 18 million tons in 2012

In the Bull Mountains mine, longwall panels were designed for a minimum of 200 feet of overburden depth. Two large shale beds, totaling about 60 feet in thickness, lie about 110 feet above the Mammoth coal seam. [93] These shale beds will likely deform plastically and inhibit stream loss from subsidence.

The Bridger Mine is located near Point of Rocks, Wyoming extracts coal from the Fort Union Formation.[94] The overburden thickness above the longwall panels ranges from about 400 feet to nearly 1000 feet.[95]

The Foidel Creek Mine is owned by Peabody Energy's Twentymile Coal Company and is located about 24 miles southwest of Steamboat Springs, Colorado. Production from the mine totaled 8 million tons in 2012. The mine extracts coal from the Wadge seam, which ranges in height from 8.5 feet to 10 feet.[96] Overburden thickness ranges from 800 feet to 1700 feet on their Sage Creek Lease.[97]

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[93] Environmental Assessment, Bull Mountains No. 1, Federal Lease MTM 97988, Musselshell County, Montana, DOI-BLM-MT-C010-2009-0010-EA., 2009.

[94] Environmental Assessment, Bridger Coal Lease Modification to WYW154595, WY-040-EA12-19, January 2013

[95] Maleki, H., Pollastro, C., "Geotechnical Program at Bridger Coal Company", 2008.

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Appendix E: Analysis of Potential Impacts to Treatment of Coal Refuse

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Morgan Worldwide Consultants, Inc.

In Conjunction with:

Industrial Economics

August 1, 2014

Table of Contents

List of Figures

List of Tables

Abbreviated Glossary

- *Alternatives* - refers to the alternatives presented in Appendix B.
- *BTU* – British Thermal Unit, is a measure of a unit of energy
- *Coal resource* – a coal seam or group of coal seams that may constitute a mineable reserve.
- *CODNR* – Colorado Department of Natural Resources
- *DTM* – Digital Terrain Model
- *Ephemeral Stream – a* stream that only flows during rainfall events.
- *Froth Flotation or Flotation process* – a chemical process that utilizes the difference in surface properties of coal to render it hydrophobic. The introduction of air in the slurry promotes the floatation of coal into a rising froth. Since rock and soil particles remain suspended in water, they are isolated from the froth.[1]
- *GIS* – Geographic Information System
- *Intermittent Stream* – a stream that flows seasonally. This type of stream has a groundwater component which fluctuates throughout the year.
- *KGS*- Kentucky Geological Survey
- *Liquefaction*- A state where the strength of saturated fine refuse material is reduced or lost due to seismic loading and the material can flow like a viscous liquid.
- *Model Refuse Facility* – a fill structure sized, using general parameters, to accommodate the total waste material generated by a particular model mine for the purpose of evaluating costs associated with the Alternatives. The fill structures included in this report are not intended to represent actual designs that would require on-site geotechnical investigations and detailed engineering.
- *MSHA* – Mine Safety and Health Administration
- *MDHB* - an acronym for "material damage to the hydrologic balance outside the permit area". This acronym is used only in the context of this report.
- *Organic efficiency* - an indicator of coal cleaning performance calculated by dividing actual clean coal yield by the theoretical maximum yield attainable at the same ash content according to a washability analysis.[2]
- *Perennial Stream* – a stream that flows throughout the year.
- *Run-of-mine coal (ROM)* - the raw mixture of coal and waste rock that is removed from an underground mine face and transported to the surface.
- *UGMM* – an acronym for "underground model mine". This acronym is used only in the context of this report. The underground model mines used in this report are identical to those presented in Appendix B.

[1] Euston, Jeff, "Two Stage Coal Flotation Using A Mechanical Cell", SME, International Coal Preparation Congress, Conference Proceedings, 2010, Page 382-390

[2] Gluskoter, Harold J., et al., "Coal Preparation Demands in the USA, Upstream Issues, Challenges, and Strategies", The Virginia Center for Coal and Energy Research, Virginia Polytechnic Institute and State University, 2008

1. EXECUTIVE SUMMARY

The purpose of this supplemental report is to evaluate coal refuse disposal facilities for the underground model mines (UGMM[3]) presented in Appendix B. This evaluation is based on the criteria specified for the eight (8) action Alternatives, which are also included in Appendix B. Since the UGMMs are considered independent operations, the waste produced by each UGMM must be managed on site. Therefore, the cost of impacts associated with the storage of this waste material was evaluated by means of model refuse facilities.[4]

Data was gathered for refuse facilities in the Northern Appalachian, Central Appalachian, Illinois Basin, and Colorado Plateau coal regions, and from this information representative refuse facilities were determined. Sites for refuse disposal facilities were chosen based on proximity to the mine portal, geographic features, and typical regional practices. Model refuse facilities were then sized for the UGMMs and the impacted stream lengths were assessed. Listed in Table 1 are the five underground model mines for which refuse facilities were added.

Region	Mining Method	Refuse Facility Type	Stream Lengths (ft)		
			Perennial	Intermittent	Ephemeral
Central Appalachian	Room and Pillar	Impoundment	0	863	391
Northern Appalachian	Longwall	Impoundment	0	3,529	10,542
Illinois Basin	Room and Pillar	Bermed Fill	0	299	2,112
	Longwall	Bermed Fill	0	1,756	5,173
Colorado Plateau	Longwall	Dry Fill	0	0	2,080

Table 1: Underground Model Mines with Refuse Facilities

The refuse facilities shown in Table 1 would normally require preparation plants to process the raw coal produced by the UGMMs. However, these plants, which would eventually cease operation and be removed, would only temporarily affect streams and, therefore, were not included in this analysis.

Alternatives 2 and 3 stipulate that placement of coal refuse material is not allowed in or near perennial streams. As shown in Table 1, no perennial streams are impacted by any of the refuse disposal facilities created for the underground model mines. However, larger refuse impoundments in Central Appalachia, where perennial streams are typically found in drainage areas of 250 acres or less, can extend into the

[3] For this report, only model mines that employ the underground mining method were used to evaluate refuse storage facilities. All references to underground model mines will use the acronym UGMM or will be written verbatim.

[4] As stated in the definitions section of this report, a model refuse facility is a fill structure sized, using general parameters, to accommodate the total waste material generated by a particular model mine for the purpose of evaluating costs associated with the Alternatives.

lower reaches of headwater basins. In addition, many refuse disposal facilities in these regions serve multiple or expansive mines and thus require substantial storage capacities.[5] Therefore, some larger refuse disposal facilities in Central Appalachia would be prohibited under Alternatives 2 and 3.

After the stream impacts were determined for the UGMMs, the costs of those impacts, based on the Appendix B Alternatives, were estimated. The costs items used to evaluate the impacts of refuse facilities were: stream enhancement, reforestation, topsoil salvage, and reclamation of organics. Table 2 lists the differences in costs relative to the Base Case for coal refuse facilities in each region. The Base Case or Alternative 1 depicts current costs, while Alternatives 2 through 9 represent costs associated with various regulatory frameworks, which are derivatives of the Base Case.[6]

Cost Condition	Alternative	Appalachian Region		Colorado Plateau	Illinois Basin	
		CAPP R&P	NAPP LW	LW	R&P	LW
Base Case	Alt 1	$1,003,200	$11,256,800	$629,100	$723,300	$2,078,700
Change in Cost From Alt 1	Alt 2	$55,481	$673,034	$123,545	$0	$0
	Alt 3	$54,543	$661,822	$123,545	$0	$0
	Alt 4	$54,543	$661,822	$123,545	$0	$0
	Alt 5	$54,543	$661,822	$0	$0	$0
	Alt 6	$0	$0	$0	$0	$0
	Alt 7	$54,543	$661,822	$123,545	$0	$0
	Alt 8	$54,543	$661,822	$123,545	$0	$0
	Alt 9	$0	$0	$0	$0	$0

Table 2: Cost Difference from Base Case

As seen in Table 2, the largest cost difference, for Alternative 2 of the NAPP longwall, is about $673,000. The largest percentage of change from the Base Case, at about 20 percent, is for the longwall mine in the Colorado Plateau region. This percentage applies to all Alternatives except for Alternatives 6 and 9. However the differential cost from the base case for this longwall mine is less than $125,000.

The findings of this report are:

Based on Table 2 and the analysis included herein, the proposed action alternatives will have negligible effect on the cost of coal refuse disposal that is associated with the underground model mines. However, the adoption of Alternative 2 or 3 could limit the construction of large Appalachian refuse impoundments, in cases where they overlie perennial streams.

2. INTRODUCTION

The purpose of this report is to evaluate impacts the Alternatives would have on the cost of coal waste disposal for the UGMMs. This evaluation is based on the criteria specified in the eight (8) proposed action alternatives. Since the UGMMs are not connected with larger mining complexes, each one is

[5] Svec, J.R., et.al, "Defining perennial, intermittent, and ephemeral channels in Eastern Kentucky: Application to forestry best management practices", USDA Forest Service, North Central Research Station, Grand Rapids, MN 55744, USA, April 2005

[6] See Appendix B for a detailed discussion of the Alternatives and their associated costs.

considered a self-contained operation. Therefore, for each applicable UGMM, a waste disposal facility would be required. The locations and types of refuse facilities included in this report are based on typical practices in each coal region. After the boundaries for these sites were established, the length and classification of streams affected by the construction of these facilities were assessed.

2.1. Background

Coal extracted from underground mines will also contain waste material from in-seam rock or clay and the inadvertent or planned removal of the floor or roof across the active face. Often small layers of shale and other non-coal material, which are commonly known as *partings*, are embedded in the coal seam. These partings vary from almost undetectable to a foot or more in thickness. As the coal seam is excavated by a continuous miner or longwall shearer, some out-of-seam material may also be removed. This mixture of coal and non-combustible material, which is often referred to as raw or run-of-mine (ROM) coal, is belted outside the mine and then transported by trucks or conveyors to a coal preparation site for processing. The result of this processing is the separation of clean marketable coal from waste (or reject) material.

Since the 1800's, coal producers have endeavored to supply a product that is relatively free of impurities. Early cleaning methods included the use of screens and picking tables. Only high quality coal was mined and rejects were controlled underground by avoiding areas where the coal seam thinned or in-seam partings increased in thickness.

2.1.1. Appalachian Basin

By World War II, with the depletion of the best Appalachian coal seams and the adoption of mechanical mining, maintaining coal quality using archaic selective-handling techniques was no longer sufficient or possible. Hence, the Appalachian coal industry began turning to preparation technology to meet their buyer's quality standards. Soon the Baum Jig washer became the primary means for freeing coal of its contaminants. Jigging, or a rapid up and down motion, involves the agitation of a basket so that particles align themselves into distinct layers according to their density. The mining industry's adoption of high production washers meant that coal seams of lesser quality could be economically mined.

Until the 1970's, only the coarse ROM material was processed. The fine ROM material, with its relatively high coal content, was diverted to the reject flow and transported and stored in refuse dumps. In the early years of coal preparation, the fines were not considered to have value. Recently, many old refuse piles have been excavated and processed through a wash plant for their coal content.

Increasing demand for coal in the expanding post-war (World War II) economy created the need for larger storage sites for the waste material resulting from coal processing. In the rugged terrain of Appalachia, coal refuse was initially dumped in uncontrolled waste piles below existing haul roads and contour benches. Subsequently, operators began storing refuse in valleys, with the coarser material used to build dams to impound fine refuse and water. These cross-valley structures were generally considered interim waste piles, not subject to engineering design standards.

On February 26, 1972, one of these structures at Buffalo Creek near Logan, West Virginia collapsed during an intense rainstorm. One hundred and twenty-five people were killed. Thousands more were injured or left homeless. After this disaster, cross-valley refuse impoundments were treated with the same thoroughness and care as large earth dams. Design criteria specific to coal refuse were developed, and Congress authorized the Mine Safety and Health Administration (MSHA) to review impoundment designs and inspect the structures under the authority of the Federal Mine Safety and Health Act of 1977.

Modern impoundments are designed and constructed with an emphasis on safety and stability. The coarse refuse is analyzed to determine is properties and compacted to a specified design density. This procedure involves compressing rather thin layers of coarse material using specialized equipment while maintaining the moisture content within a pre-defined range. A coarse refuse embankment is usually built to accommodate an access road along its face in addition to providing a stable structure to securely contain fine refuse and water.

Additional concerns have arisen with regard to possible inadvertent slurry discharges from impounding refuse facilities. On October 11, 2000, Martin County Coal Corporation, located near Inez, Kentucky, experienced a massive slurry release through underground mine works located beneath the basin of their refuse impoundment. Subsequently, MSHA and the Office of Surface Mining Reclamation and Enforcement (OSMRE) began scrutinizing underground works as a possible conduit for slurry and not just as a subsidence risk to the structure.

Conditions that affect the need for new coal refuse impoundments include the current lifespan and the potential for expansion of existing coal refuse impoundments, the amount of local underground reserves, the viability of the coal market, and the number and character of alternative refuse storage sites. Companies may choose to enlarge their existing facilities rather than construct new ones. This approach sidesteps many regulatory requirements by incrementally raising an impoundment, within its current footprint, until its maximum capacity is reached. In this case, a minimal number of stream segments would be impacted. Expanding an existing refuse impoundment may add many years to its life and reduce the need for a new refuse facility. Companies would likely deem this approach as their most economically viable option for the disposal of waste material.

Alternative disposal sites may be considered if a refuse impoundment is nearing the end of its life. These sites would include previously surface mined areas with relatively flat surfaces and decks of completed refuse impoundments. These areas can be used to encase fine refuse in compacted coarse refuse cells. After the fines dewater, these slurry cells are covered with a layer of compacted coarse refuse and the process begins anew. As with the previous example, this type of waste disposal method can postpone the need for a new refuse impoundment.

Another option to extend the life of an existing refuse impoundment may be to modify a preparation plant by adding a tailing belt press circuit or other dewatering devices. A dewatering circuit will accept the underflow from a thickener and can reduce the moisture content of fines waste, leaving slurry that consists of approximately 30% solids. Subsequently, fine waste can be mixed with the coarse refuse and possibly remove the need for a settling basin, resulting in a more efficient refuse disposal facility. However, the relatively high moisture content can remain a serious impediment to achieving a stable structure.

Declining demand for coal in Central Appalachia has affected both surface and underground mining. This decline is due in part to an oversupply of natural gas, the depletion of favorable coal reserves, and increasing regulatory requirements. With sagging coal production, companies may not consider constructing expensive, new refuse disposal impoundments when other waste storage options are available.

2.1.2. Illinois Basin

During the 1920s, Midwest coal operators experienced advances in coal loading technology and surface mining. Due to these changes, the quality of their coal product, which was already inferior to Appalachian coal, diminished even further. These developments compelled operators to begin adopting coal processing methods to rid their coal of waste material and raise its quality to a more competitive level. The widespread emergence of coal stokers in the 1930s and 1940s further accelerated the coal industry's acceptance of preparation technology.[7]

With an increase in coal processing, the storage of waste material (coarse and fine refuse) became a concern for both operators and nearby communities. Originally, coarse refuse was stored in gob piles with widths up to 1500 feet or more and rising to over 100 feet in height. These gob piles became dark blemishes on many rural landscapes. Fine refuse or slurry was stored in disposal cells behind berms or levees, in valleys and mine pits, or at other accessible locations. After slurry was pumped from a plant to a disposal cell, particles of fine refuse would settle to the bottom of the basin. Typically, water would then either evaporate or seep through a gob levee to a make-up water reservoir used for coal processing.[8]

Currently, the state of Illinois is experiencing an increase in longwall mining. Accompanying this increase is the need for more and larger refuse disposal facilities. Hillsboro Energy Company, LLC, which operates the Deer Run longwall mine near Hillsboro, Illinois, has recently received approval to convert its 151 acre refuse disposal area from an incised storage pond to an impoundment. This conversion will be accomplished by installing a 40-mil liner and filling a notch in its existing berm.[9]

Safety concerns increase as impoundments are raised above the existing ground and the quantity of fines that is stored increases. As has been observed in Central Appalachia, higher underground coal production in Illinois will increase the need for more and larger refuse storage facilities.

2.1.3. Colorado Plateau

In the 1860s, coal mining in Colorado was initiated to service small towns that had formed near hardrock mining sites. In addition, coal mining serviced emerging communities founded on the High Plains and provided fuel for railroad locomotives. Later, coke, used in iron and steel plants, opened-up an additional market for coal. However, in 1900, the U.S. coal industry began a long decline due primarily to the increasing use of petroleum and natural gas. In Colorado, the waning hardrock mining industry and the railroad's growing preference for fuel oil further weakened the demand for coal. World War I and World War II caused temporary spikes in coal demand, however, soon after each conflict ended, coal's steady descent resumed.

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[7] Harper Denver, et al., "Coal in Indiana: Reconnaissance of Coal-Slurry Deposits in Indiana", Indiana Geological Survey, Bloomington, Indiana, circa 2007

[8] *Id.*

[9] Illinois Department of Natural Resources, "Permanent Program Finding, Results of Review, Permanent Program Revision Application No. 1 to Permit No. 399, Hillsboro Energy LLC, Deer Run Mine", December 20, 2011

By the 1960s, Colorado's coal industry appeared to be in final collapse as the use of coal as a heating fuel had dropped to 3% of the nation's households. However, the rising demand for electricity rescued the industry as power companies looked to coal as a cost-effective fuel for the generation of electricity. Amendments to the Clean Air Act in 1990 focused demand on low-sulfur coal, which is plentiful in Colorado. With a market for coal firmly established, the industry could pursue long-term, capital-intensive operations, such as longwall mines. By the mid-1990s, underground mining comprised about 70% of Colorado's output. Currently, underground mines supply about 60% of Colorado's coal production per annum.[10]

In the past mines in Colorado and Utah have shipped coal raw, but with declining quality in the remaining mineable coal seams, many companies have begun processing their raw coal to remove impurities. However, unlike the Appalachian and Illinois basins, mining operations in Western states have water supply issues. The shortage of water in the West eliminates the option of operating a fine coal cleaning circuit that is commonly used in the East. Consequently, Western mining facilities will normally wash the raw coarse material and, subsequently, blend the unwashed (or raw) fines with the clean coarse coal. The reject material is permanently stored in a dry, non-impounding fill. This process generally produces a saleable product that surpasses the customer's minimum requirements.[11]

2.2. Material Damage and Stream Restrictions

The proposed definition of "material damage to the hydrologic balance outside the permit area" (MDHB) is "any quantifiable adverse impact on the quality or quantity of surface or ground water or on the biological condition of any perennial or intermittent stream that would preclude any designated use under the Clean Water Act or any existing or reasonably foreseeable designated use of surface or groundwater outside the permit area." The definition includes limitations on impacts involving refuse disposal facilities (See EIS, Chapter 2).

Alternatives 2 and 3 will limit the types of streams that can be impacted by refuse facilities. See Table 3 below. For a more detailed breakdown of each alternative, refer to the *Alternatives* section of this report and Appendix B.

[10] Fell, James E., Twitty, Eric, "National Register of Historic Places, Coal Mining Industry in Colorado: 1858-2005", Mountain States Historical, 2008.
[11] Kilma, Mark S., Arnold, Barbara J., Bethell, Peter J., "Challenges in Fine Coal Processing, Dewatering, and Disposal", SME, 2012.

Alternative	Stream Type		
	Perennial	Intermittent	Ephemeral
1	√	√	√
2	***Not Allowed***	√	√
3	***Not Allowed***	√	√
4	√	√	√
5	√	√	√
6	√	√	√
7	√	√	√
8	√	√	√
9	√	√	√

Table 3: Stream Restrictions

2.3. Organization of This Report

Listed below is the general layout of the remainder of this report.

Section 2 - Introduction. This section lays the framework for this study. The background, scope, study areas, and limitations are discussed and defined.

Section 3 – Coal Preparation. This section presents an overview of coal preparation. Also, coal refuse is discussed along with various storage options for the material.

Section 4 – Model Refuse Facilities. Refuse facility models are discussed in this section.

Section 5 –Discussion and Results. This section discusses the refuse facility models and presents the results of the study.

Section 6 – Conclusions.

2.4. Scope of Study

This study consists of the sizing of representative refuse facilities and a review of the impacts from the application of the alternatives. The effects of each alternative on the model coal refuse facilities are evaluated by estimating the costs associated with stream enhancement reforestation, organics reclamation, and topsoil salvage.

2.5. Limitations

As a supplemental analysis to Appendix B, the objective of this report is to estimate the total impact of refuse disposal for each UGMM. Refuse facilities were sized to contain the waste material generated by processing the raw coal from the UGMMs. Total waste generated, refuse storage capacity (based on topography), embankment slope, stream gradient, and type of refuse facility (based on regional practices) were the major factors used to locate and delineate these structures.

Limitations for this report include:

- Data used in this report that originates from publically available sources has not been independently verified.
- The review of refuse and preparation plant facilities included in this report is not intended to be a complete log of these facilities, but rather it is illustrative of current conditions relating to coal processing.
- The criteria used to size the model refuse facilities presented in this report are general and intended only to approximate perimeters of the structures and estimate impacted stream lengths. Actual designs of refuse structures would require extensive site investigations and detailed analyses that are beyond the scope of this report.
- Certain parameters specified for the underground model mines, which are documented in Appendix B, are used in this report without further analysis. Refer to Appendix B for more information on parameters assigned to the model mines.
- Since preparation plants would only temporarily affect streams, they were not included in the estimation of costs.
- The refuse facility sized for an UGMM serves only that model mine, with no connection to larger, multiple-mine complexes.
- Beyond those included in this report, no additional restrictions for the selection of refuse disposal sites were considered.
- Procedures for determining the beginning of jurisdictional streams were adopted from Appendix B.
- No cross-regional method for identifying the intersection point (I/P) between perennial and intermittent streams was found, based on the information reviewed for this report. However, a study by the USDA Forest Service in 2005[12] included guidelines for the identification of I/P points in Eastern Kentucky. Their locations are based on stream and watershed properties such as drainage area and stream gradient. Conclusions based on this study were applied only to the Central Appalachian region.
- Many design aspects, including stability analyses, were not included in this report. Nonetheless, all refuse facilities were located on natural ground slopes (at toes of fills) that were less than 13 degrees and fill outslopes were set at 2-foot horizontal to 1-foot vertical with 20-foot wide benches placed at every 50-foot rise in elevation.
- The model mine maps used in Appendix B were also used in this report to size the refuse facilities. Therefore, the assumptions and restrictions used for the mapping of the model mines would also apply to this report.
- Total waste material was used to size the model refuse facilities. Coarse and fine refuse were not differentiated.

[12] Svec, J.R., et.al, "Defining perennial, intermittent, and ephemeral channels in Eastern Kentucky: Application to forestry best management practices", USDA Forest Service, North Central Research Station, Grand Rapids, MN 55744, USA, April 2005

- Inflows from spoil aquifers, underground mines or other secondary sources that may raise the classification of streams were not considered in this report.
- Preparation plant efficiency was not considered in this analysis.
- Depending on the coal seam and the extraction method, rejects can vary widely, ranging from about 20% to 50% of the raw feed[13]. Reject percentages assigned to the UGMMs fall within this range and are considered average values.

2.6. Review of Coal Refuse Disposal and Preparation Plant Facilities

Initially, a review of coal preparation and refuse facilities was undertaken to identify coal waste facilities and their associated preparation plants throughout the United States. Since coal processing plants and refuse facilities are closely linked, they were reviewed in tandem.

Coal Age® Magazine produces a yearly census of preparation plants based on data that they have obtained from MSHA. This census lists plants by state, operator, plant name, and other pertinent information. For the purposes of this report, the Coal Age® census was assumed to be representative of the current population of coal processing plants in the United States[14]. Although the Coal Age® census offers a valuable index of preparation plants, it did not include locations for these facilities. Therefore, other sources were sought to provide location information.

A key source used to locate refuse facilities was the *Coal Impoundment Location and Information System* (coalimpoundment.org), which includes coal refuse impoundments in Kentucky, Illinois, Indiana, Ohio, Pennsylvania, Maryland, Tennessee, and West Virginia. This database was also used to identify preparation plants not included in the Coal Age® census.

Listed below are additional sources used in this review of processing plants and coal refuse facilities, with Google Earth® providing visual confirmations in some cases.

- United States Geological Survey (USGS)
- Mine Safety and Health Administration (MSHA)
- United States Securities and Exchange Commission (SEC) 10-K Reports
- Kentucky Geological Survey (KGS)
- West Virginia Department of Environmental Protection (WVDEP)
- Colorado Department of Natural Resources (CODNR)
- Tennessee Department of Environment and Conservation (TNDEC)
- Virginia Department of Environmental Quality (VADEQ)
- Illinois Department of Natural Resources, Office of Mines and Minerals
- Alabama Surface Mining Commission
- Indiana Department of Natural Resources, Division of Reclamation

[13] National Research Council. *Coal Waste Impoundments: Risks, Responses, and Alternatives*. Washington, DC: The National Academies Press, 2002.
[14] The Coal Age census was used as the basis for identifying preparation plants in the United States. Other sources were also accessed that supplemented the census data with additional processing plants.

As shown in and Table 5, Preparation plants and refuse facilities are also located in the Southern Appalachian Region and the Northern Rocky Mountain and Great Plains Regions. Since these regions had no model mines, they were not included in the analysis of refuse facilities.

The regions with the largest number of preparation plants, Central Appalachia (144), Northern Appalachia (78) and Illinois Basin (48), also contain the largest number of refuse sites. The ratios of refuse sites to existing preparation plants are shown below.

- Central Appalachia 1.1 refuse sites for each prep. plant
- Northern Appalachia 1.5 refuse sites for each prep. plant
- Illinois basin 3.3 refuse sites for each prep. plant

Although Central Appalachia has the largest number of refuse sites (162), it is one of the most efficient[15] regions at about one refuse site for each preparation plant. This low ratio may be indicative of the limited number of locations available for refuse facilities due to the steep terrain and other geographic constraints.

Northern Appalachia has a slightly higher ratio (1.5 to 1) that may, as with Central Appalachia, reflect its limited number of locations for refuse facilities. The Illinois Basin has a significantly higher ratio at 3.3 refuse sites to one preparation plant. This higher number may be, in part, the result of this region's long history of processing coal in order to obtain a more competitive product.

With only eight preparation plants and seven refuse facilities in operation, the Colorado Plateau region is expected to increase its use of refuse facilities in the future. However, the refuse facilities in this region do not impound water.

[15] Within this context, efficiency is based solely on the number of refuse facilities, without consideration of their sizes and other factors.

Regions	Number of Plants	Precentage of Plants
Central App	**144**	**49.83%**
Kentucky	56	19.38%
Virginia	22	7.61%
West Virginia	66	22.84%
CO Plateau	**8**	**2.77%**
Colorado	5	1.73%
Utah	3	1.04%
Ill Basin	**48**	**16.61%**
Illinois	17	5.88%
Indiana	15	5.19%
Kentucky	16	5.54%
Northern App	**78**	**26.99%**
Maryland	2	0.69%
Ohio	21	7.27%
Pennsylvania - Bituminous	27	9.34%
Pennsylvania - Anthracite	16	5.54%
West Virginia	12	4.15%
NRMGP	**1**	**0.35%**
Montana	1	0.35%
Southern App	**10**	**3.46%**
Alabama	7	2.42%
Tennessee	3	1.04%
Grand Total	**289**	**100%**

Table 4: Preparation plants by region and state[16]

[16] Fiscor, Steve. "U.S. Preparation Plant Census." *Coal Age® Magazine*. Oct 2011: 36-43. Print.

Regions	Number of Refuse Facilities	Percentage of Refuse Facilities
Central App	**162**	**34.2%**
Kentucky	91	19.2%
Tennessee	2	0.4%
Virginia	4	0.8%
West Virginia	65	13.7%
Colorado Plateau	**7**	**1.5%**
Colorado	6	1.3%
Utah	1	0.2%
Illinois Basin	**158**	**33.3%**
Illinois	108	22.8%
Indiana	26	5.5%
Kentucky	24	5.1%
Northern App	**119**	**25.1%**
Ohio	37	7.8%
Pennsylvania	40	8.4%
West Virginia	42	8.9%
NRMGP	**1**	**0.2%**
Montana	1	0.2%
Southern App	**27**	**5.7%**
Alabama	26	5.5%
Tennessee	1	0.2%
Grand Total	**474**	**100%**

Table 5: Refuse Facilities by Region and State[17]

Locations of refuse facilities are shown in Figure 1.

[17] Various sources were used to compile this list of refuse facilities. This table is not intended to include all refuse facilities in the U.S., but rather it is a representative view of the current use of refuse facilities in the coal regions.

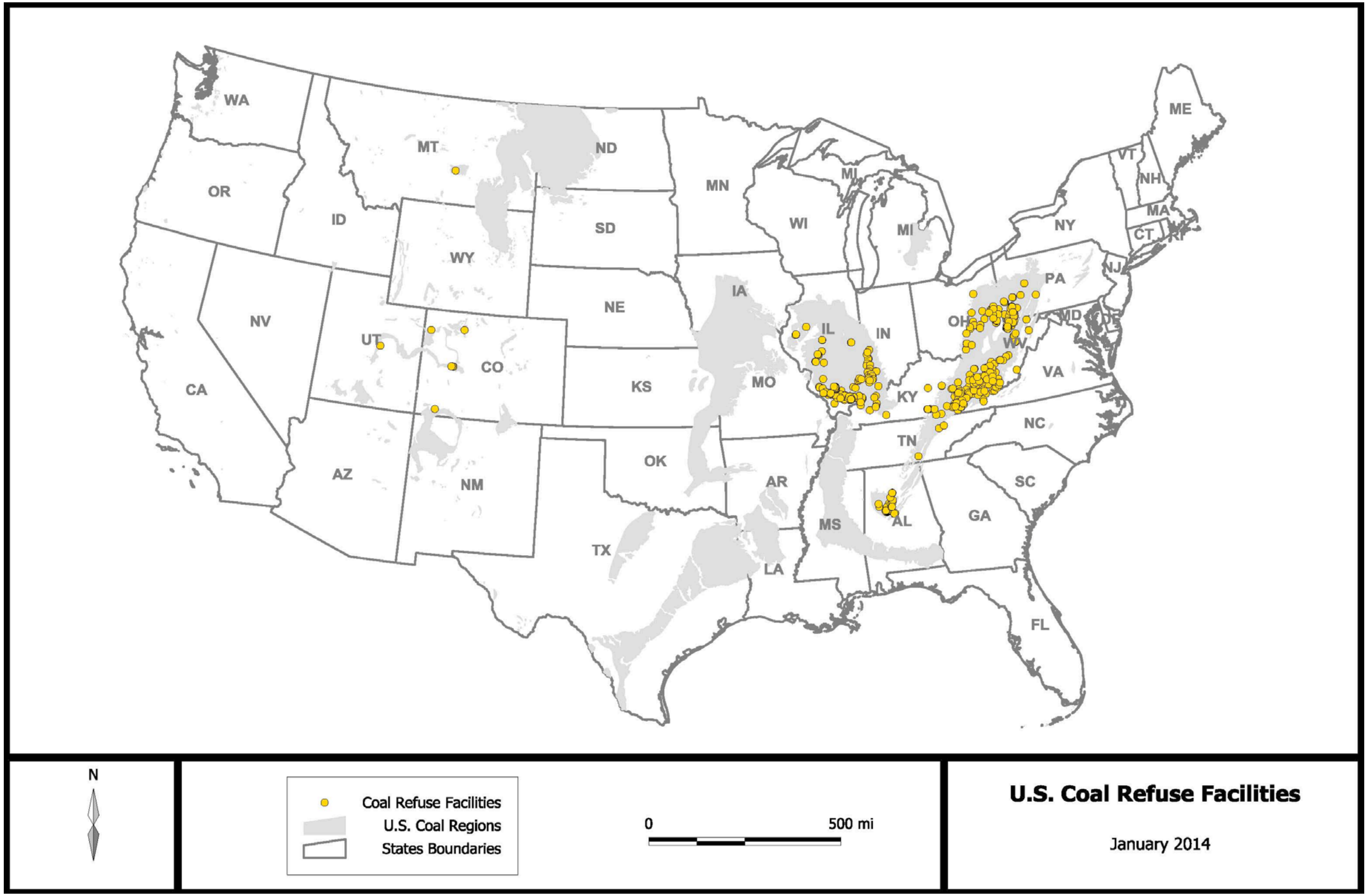

Figure 1: U.S. Coal Refuse Facilities

2.7. Study Areas

Coal processing plants and refuse impoundment facilities are located throughout the United States; however, the majority of the facilities, about 77%, are located in the Northern and Central Appalachian Coal Regions. These regions include the states of West Virginia, Kentucky, Pennsylvania, Virginia, and Ohio. Figure 2 shows the locations of coal regions.

In 2012, four coal regions produced about 93% of the underground coal mined in the United States.[18] These regions are:

- Northern Appalachia (30%)
- Central Appalachia (23%)
- Illinois Basin (27%)
- Colorado Plateau (13%)

Each of the remaining coal regions yielded less than 4% of the total underground production. The four regions listed above were chosen for modeling underground mines with corresponding refuse disposal facilities. Each model is based on typical mining and refuse disposal practices in its corresponding region.

Region	Number of Underground Mines	Percentage of Underground mines
Northern Appalachia	85	17.5%
Central Appalachia	333	68.5%
Southern Appalachia	8	1.6%
Illinois Basin	38	7.8%
Gulf Coast	0	0.0%
Northern Rocky Mtns & Grt Plns	2	0.4%
Colorado Plateau	18	3.7%
Western Interior	2	0.4%
Northwest	0	0.0%
TOTAL	**486**	**100%**

Table 6: Regional Underground Mines in the United States[19]

[18] MSHA 2012 Data and analysis by Energy Ventures Analysis, Inc (received April 16, 2013).
[19] MSHA 2012 Data and analysis by Energy Ventures Analysis, Inc (received April 16, 2013).

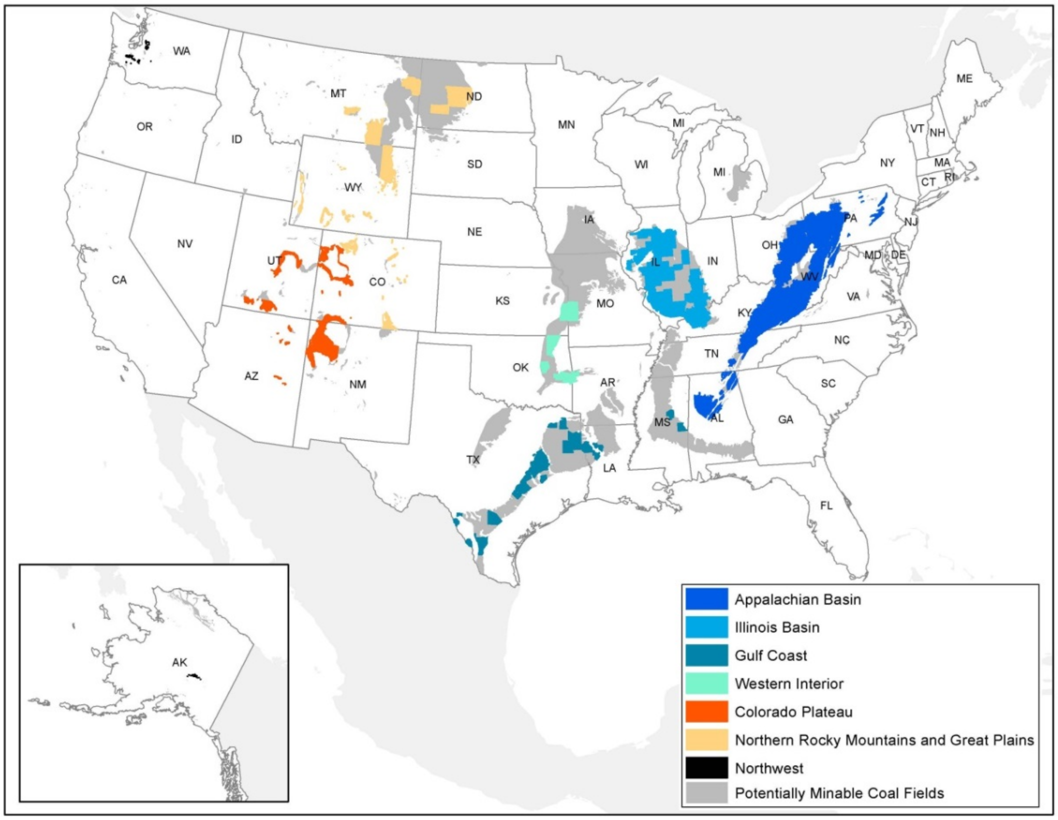

Figure 2: United States Coal Regions

2.8. Alternatives

Each alternative represents an operating scenario which defines the working elements, from which costs associated with various actions are estimated. The first alternative is the base case, which summarizes the current practices of coal mining across the United States. The remaining alternatives, 2 through 9, are action alternatives, which are derivatives of the base case. See Appendix B for specifics concerning each of the Alternatives.

2.9. Model Mines

The underground model mines presented in Appendix B were used as a basis for evaluating the effects of the Alternatives on the defined costs items associated with refuse disposal facilities. The UGMMs are considered as representative of the types of mining operations that are commonly found in each coal region.

For this report, UGMMs were assumed to be independent and self-contained mining operations and not part of a larger mining complex. The following UGMMs were evaluated in this study.

#	Region	Mining Method
1	Northern Appalachia	Longwall
2	Central Appalachia	Room and Pillar
3	Illinois Basin	Room and Pillar
4	Illinois Basin	Longwall
5	Colorado Plateau	Longwall

Table 7: Underground Model Mines

3. Coal Preparation

Coal extracted from underground mines will also contain waste material from in-seam rock or clay, and the inadvertent or planned excavation of the floor or roof across the active mine face. This mixture of coal and non-combustible material, which is referred to as raw or run-of-mine (ROM) coal, is belted outside the mine and then transported by trucks or conveyors to a coal preparation plant for processing. The result of this processing is the separation of clean marketable coal from waste, or reject, material. The waste is transported away from the preparation site to a nearby refuse storage facility. The type of refuse facility that is constructed depends in part on the nature and quantity of the waste produced from the preparation plant.

3.1. Coal Processing Plants

Coal processing plants extract coal from ROM material by employing crushers, mechanical screens, float tanks, cyclones, centrifuges, and drying devices. This waste may consist of shale, sandstone, clay, and a small amount of coal, usually assumed at five percent of the total ROM coal processed. Coal is lost due to a plant's inherent inefficiencies.

Where required, modern coal preparation plants process and clean both coarse and fine ROM material. After pre-processing, larger fragments of the ROM material are typically directed through a Jig or Heavy Media vessel. Jigging, or a rapid up and down motion, involves the agitation of a basket so that particles align themselves into distinct layers according to their density. Modern jigs use air pulsations to simulate this jigging action and induce the separation of particles. Heavy media technology employs very fine magnetite particles in suspension to control the specific gravity of the fluid and allow the separation of coal and reject material. Generally, jig plants cost less to purchase and operate than heavy media plants, but heavy media technology allows for finer control and, consequently, can produce higher yields of marketable coal.[20]

Depending on the type and predictability of plant feeds, operators may prefer alternatives to vessel separation devices. In some cases, very large heavy media cyclones are used.

When processing fine coal, the heavy media cyclone is the most widely used technology today and can clean sizes down to 1 mm. The 1-mm by 100-mesh size fraction is processed with devices such as water-

[20] Short, M.A., et. al, "The Economics of Wet Jigging", 2002

only cyclones, spirals, and hindered-bed settlers. If coal below 100-mesh is retrieved, a froth flotation device is commonly used.

Thickeners allow the recovery of water for recycling after the processing of fines. Normally, an automatic flocculent dosing system is employed that samples feed well water and administers the appropriate treatment. Flocculants cause suspended particles to aggregate into clusters of increasing size, which ultimately settle to the bottom of the thickener. Clarified water is pumped back into a freshwater holding tank for reuse, while the settled fines are removed by a slurry pump as underflow.

Thickener underflow can be further dewatered using devices such as belt filter presses, vacuum filters, plate and frame filters, solid bowl centrifuges, horizontal belt filters, and paste thickeners. The solids content of dewatered fines refuse may increase up to 30 percent[21], becoming a paste-like substance (or filter cake) with reduced variability in grain size. This material can then be blended with coarse refuse and used to construct a combined refuse structure. However, due to its relatively high moisture content, the filter cake cannot always be blended with coarse refuse and, therefore, may need to be stored in slurry cells or a similar structure where stability requirements are met. Inclement weather may also the raise moisture content of refuse to unacceptable levels, further complicating the blending and compaction process.[22]

In the Colorado Plateau region the ROM coal tends to be low in ash and fines content. The higher quality of this coal is due to less in-seam and out-of-seam rock in the raw product. With these conditions, a coarse-only preparation plant can produce a marketable product when washed coarse coal is combined with unprocessed fines. Coarse-only plants require much less water than their eastern counterparts and their refuse consist of larger fragments with little fines. With water conservation being a critical issue in many western states, processing only coarse coal allows underground mining operations to continue with less concern about the quality of their final clean coal product.[23]

3.2. Coal Refuse

The processing of ROM coal results in the inevitable accumulation of non-combustible refuse. This waste material consists of fine particles (fine refuse) and larger fragments known as coarse refuse. Plant reject rates typically range from 20 to 50 percent of the plant feed and are dependent on the quality of the ROM material and the design and operating efficiency of the plant. Variability in the mining process, for instance when additional roof or floor is excavated, can substantially alter the amount and consistency of the refuse produced by the plant.[24]

Coarse refuse represents the majority of material in the waste stream of a preparation plant. It is generally a well graded material, varying in size from 0.02 inches (0.6 mm) up to 3 inches (76 mm).[25] The coarse

[21] Cousins, Bret G., "Alternatives to Coal Mine Tailings Impoundment – Evaluation of Three Dewatering Methods at Rockspring Coal Mine", Society for Mining, Metallurgy and Exploration, Seattle, Washington, Feb. 2012
[22] Gardner,J.S., et. al, "Alternatives Analysis for Coal Slurry Impoundments", SME, Feb. 2003
[23] Beethell, Peter, "Arch Coal Processing Philosophy, East and West", SME, International Coal Preparation Congress, Conference Proceedings, 2010
[24] National Research Council. *Coal Waste Impoundments: Risks, Responses, and Alternatives*. Washington, DC: The National Academies Press, 2002. pages 20-23
[25] Leonard, Joseph W. *Coal Preparation*. New York: The American Institute of Mining, Metallurgical, and Petroleum Engineers, INC, 1979 Print (PDF). Page 16-12

reject typically has specific gravity ranging from 1.8 to 2.3, water content between 8 and 15 percent, and can be compacted to form a relatively dense fill in embankments[26].

The fine refuse is material smaller than .02 inches (0.6 mm), consisting of a mix of fine coal particles, sand, clay, silt, and water. This blend of these fines and water, called *slurry*, is pumped to the impoundment basin where the particles are allowed to settle. The clarified water is recycled to the processing plant or discharged to the sediment pond.

Due to lower ash content in their coal, western regions can blend their unwashed fines with their washed coarse coal and meet their client's specifications. Therefore, western regions do not require fines processing circuits in their preparation plants or have the need for slurry impoundments.

3.3. Coal Refuse Disposal Facilities

Refuse disposal facilities are generally categorized as impoundments, combined refuse, slurry cells, bermed refuse impoundments or dry fills. The type of refuse disposal facility required depends on topography, coarse to fine refuse ratio, quantity and properties of the refuse, the characteristics and efficiency of the preparation plant, and other factors. The following subsections discuss various types of refuse facilities.

3.3.1. Impoundments

In Central Appalachia and many areas in Northern Appalachia, steep topography generally leaves few options for the disposal of refuse material. Therefore, refuse impoundments constructed as cross-valley embankments are the typical means for storing waste material resulting from the processing of coal. See Figure 3. Coarse waste material is transported by trucks and conveyors to the refuse disposal facility, while fine waste material is normally transported as slurry through pipelines to the basin of the impoundment.

Processing wastes can range from 20% to 50% of the ROM coal or raw feed to the plant.[27] If a preparation plant uses wet processes to clean the ROM coal, it typically requires an impoundment to store the waste. The refuse created by the cleaning process is comprised of both coarse and fine waste. Coarse refuse material is used to construct the embankment for the impoundment[28]. Fine refuse is typically a blend of fine coal, sand, clay, silt, and water. The solid particles in the slurry are less than 0.02 inches (0.6 mm) in diameter. The slurry is pumped behind the embankment where the fine particles are allowed to settle.

[26] D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). page 2-8

[27] National Research Council. *Coal Waste Impoundments: Risks, Responses, and Alternatives*. Washington, DC: The National Academies Press, 2002. page 36

[28] D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). page 2-8

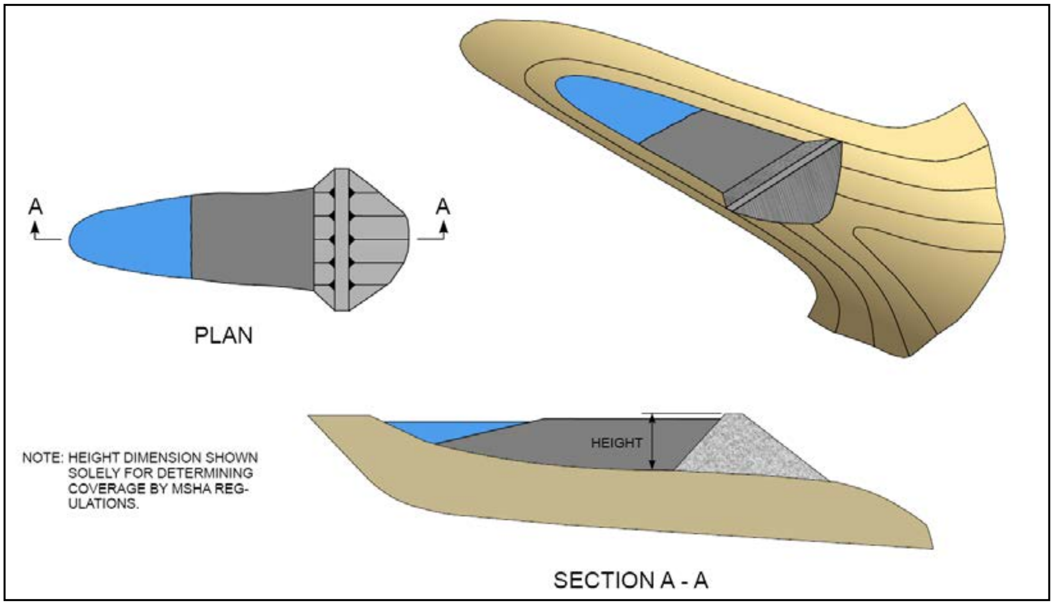

Figure 3: Cross Valley Refuse Impoundment[29]

Impoundments are typically constructed in stages, where each successive stage is built on top of previous stages. There are three methods of constructing staged impoundments.

The *Upstream Staging Method* (Figure 4) consists of building successive stages upstream of the toe of the original embankment. Each new phase of the embankment is constructed on top of fine waste. Under static loading conditions, the viability of this method is dependent upon the strength of the consolidated fines material within the zone of shearing, steepness of the downstream slope of the embankment, and the location of the phreatic line within the embankment. Under seismic loading, this method is dependent upon the resistance of the fines material to liquefaction.[30]

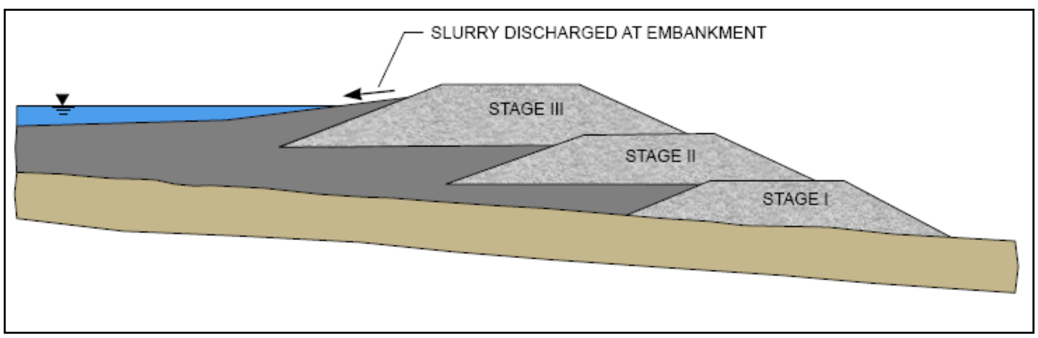

Figure 4: Upstream Staging Methods [31]

In the *Downstream Staging Method* (Figure 5), successive embankment stages are constructed downstream of the original embankment. This method requires a greater amount of coarse material to

[29] D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). page 3-5
[30] National Research Council. *Coal Waste Impoundments: Risks, Responses, and Alternatives*. Washington, DC: The National Academies Press, 2002.
[31] D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). Pages 3-8, 3-9

build each new stage and is typically used when the ratio of fine to coarse refuse is low. The embankment is not constructed on fine waste material and is considered to be more stable than those constructed using the upstream method. Disadvantages to this method are increasing volumes of coarse refuse are required for each new stage, reclamation of the embankment face is delayed until completion of the final stage, and downstream facilities may conflict with an expansion.[32]

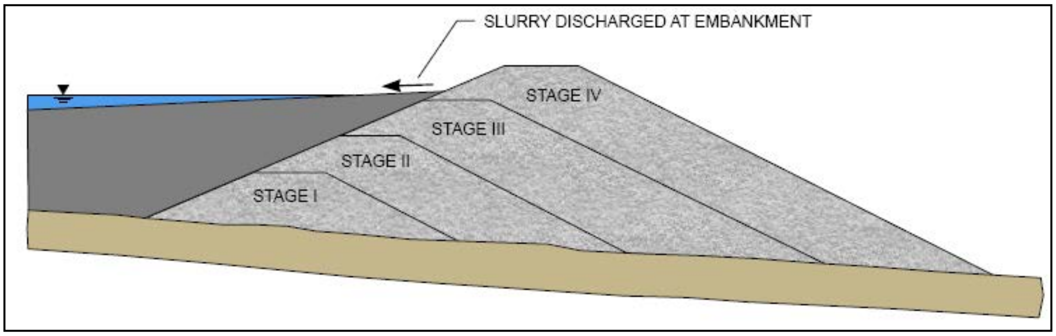

Figure 5: Downstream Staging Method [33]

Finally, the *Centerline Staging Method* (Figure 6) is defined by construction of successive embankments on the centerline or the original embankment. This method is a hybrid of the first two methods.

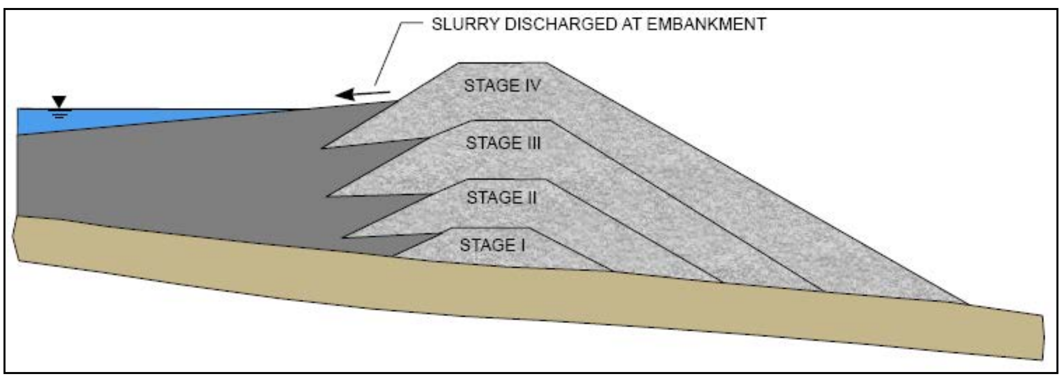

Figure 6: Centerline Staging Method[34]

Due to the mountainous terrain in the Central and Northern Appalachian Regions, the majority of refuse is disposed in cross-valley refuse impoundments. Processing waste may also be disposed on abandoned mine lands or, possibly, in abandoned underground mines. When constructing a refuse impoundment, coarse refuse is used to construct an embankment dam across the valley[35]. This dam naturally forms an impounding basin behind it, which allows for the storage and settlement of fines from the pumped slurry (Figure 3).

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32 National Research Council. *Coal Waste Impoundments: Risks, Responses, and Alternatives*. Washington, DC: The National Academies Press, 2002.
33 D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). Pages 3-8, 3-9
34 *Id.*
35 D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). page 2-8

When using wet processing, a larger basin is needed to hold the liquefied fines mixture also known as *slurry*. This basin also serves as settling pool for the fines, particularly when the upstream construction method is employed. Hence, the basin size and shape is critical in the beginning stages of the embankment construction. Ideally, for each 10-foot rise in elevation, several acre-feet of basin pool volume would be generated. The water level in the pool is maintained by pumping clarified water from the back of the impoundment to a perimeter ditch or to the inlet of the decant pipe. The discharge then flows to the sediment pond located below the toe of the refuse impoundment.

Since the embankment face also encompasses an access road, turnarounds, and safety benches, its composite slope can be considerably reduced, thus increasing the volume of coarse refuse needed to raise the embankment and increase pool capacity. Coarse to fines ratios are usually estimated by evaluating the raw coal produced from comparable mines in the area. However, this ratio can fluctuate, particularly when raw coal from multiple mines is being processed. This scenario would slow construction of the coarse refuse embankment while potentially elevating the fines pool to critical levels. Therefore, from an operational perspective, targeting valleys with substantial storage capacity and that are not excessively wide in the embankment area would be deemed a central factor in the planning and design of these structures.

3.3.2. Combined Refuse Fills

In some cases, combined refuse impoundments are constructed. The embankment construction process does not differ; however, the slurry pumped behind the embankment is altered. In the combined method, fine refuse, which has been reduced in moisture, is combined with coarse refuse. This combined refuse material (Figure 7) is usually placed in the basin area as cap material or behind the embankment in cells.[36]

Combined refuse fills consist of a combination of dewatered fines and coarse refuse. Typically, fines that are dewatered using belt filter presses will have a minimum moisture content of 30% while coarse refuse normally has a moisture content ranging from 5% to 9%. When these two materials are blended, the combined moisture can easily exceed the optimum moisture content for proper densification of this material. Additionally, precipitation events can raise the moisture content even more, creating a material that requires extensive drying before compaction efforts can be effectively implemented.[37]

[36] *Id*.
[37] Gardner, J.S., et. al, “Alternatives Analysis for Coal Slurry Impoundments”, SME, Feb. 2003

Figure 7: Combined Coal Refuse Material[38]

3.3.3. Slurry Cells

Slurry cells are considered by many as the preferred means for storing refuse. This type of structure consists of slurry pumped inside a rectangular encasement of coarse refuse. Slurry cells require a high coarse to fine refuse ratio to provide sufficient material for dikes between cells and for caps between layers of cells. A series of slurry cells are typically constructed on a relatively flat area. These areas may consist of abandoned surface mines or in filled basins of refuse impoundments.

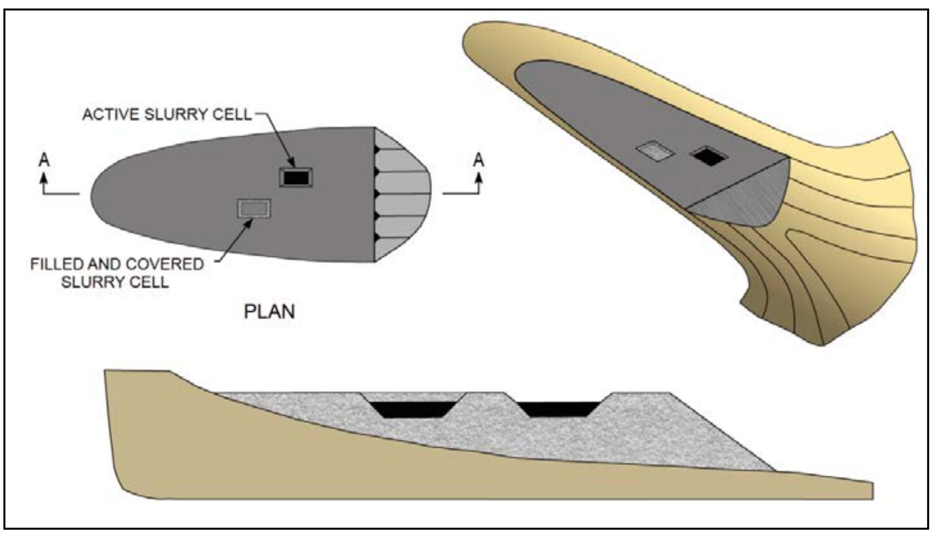

Figure 8: Slurry Cell in Valley Fill, Non-Impounding Embankment

[38] D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). page 2-10

3.3.4. Bermed Refuse Impoundments

The gentle terrain in the Illinois Basin Region is most suitable for the construction of Bermed Refuse Impoundments. Embankments, consisting of fill material and/or coarse refuse, are built to impound the fine refuse (Figure 9). These containment cells are relatively shallow, but have larger surface areas compared to the cross-valley impoundments typically found in Central and Northern Appalachia.

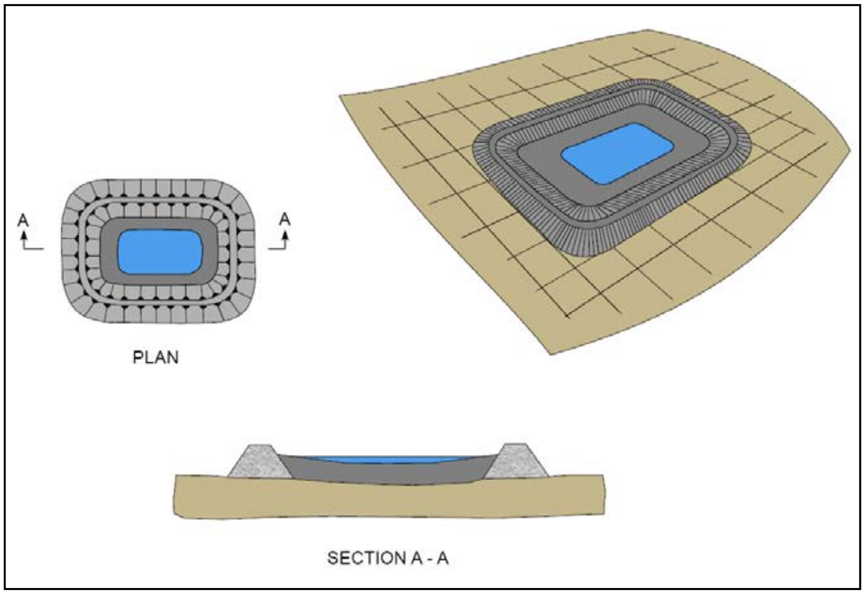

Figure 9: Bermed Refuse Impoundment [39]

3.3.5. Dry Refuse Fills

Dry fill refuse disposal facilities are predominate in the western United States. Because of its low ash levels, western coal has traditionally been shipped unwashed. With no need to handle and store refuse material, processing consisted of screening and sizing the coal product. However, in recent years, mines in Colorado and Utah have been extracting thinner coal seams with higher ash content. Therefore, current practice for Western mining facilities is to wash the raw coarse material and, subsequently, blend the unwashed (or raw) fines with the clean coarse coal. This process generally produces a saleable product that surpasses the customer's minimum requirements. Coarse reject material is permanently stored in a dry, non-impounding fill.

4. MODEL REFUSE FACILITIES

This report evaluates waste disposal facilities associated with the model underground mines presented in Appendix B. This evaluation is based on the criteria specified in the eight action alternatives. Each refuse facility included in this report is based on typical practices found in their corresponding coal region.

[39] D'Appolonia Engineering. *Engineering and Design Manual : Coal Refuse Disposal Facilities:* MSHA – Mine Waste and Geotechnical Engineering Division, 2009. Print (PDF). pages 3-8

Appendix B defines five model underground mines in four regions where underground coal mining occurs. These regions include Northern Appalachia, Central Appalachia, Illinois Basin, and the Colorado Plateau. The model underground mines for each region are listed below.

- Northern Appalachia Longwall Mining
- Central Appalachia Room and Pillar Mining
- Illinois Basin Room and Pillar Mining
- Illinois Basin Longwall Mining
- Colorado Plateau Longwall Mining

Using the information gathered from the review of preparation facilities, regional trends for coal processing were defined. These trends were analyzed for each region. The models were then used to evaluate the effects of the alternatives on coal refuse facilities. The size of the model refuse facilities is based on the average reject percentages assigned to each UGMM. See Table 8 below.

Region	Mine #	Mining Method	Average Percent Reject
Northern Appalachia	1	Longwall	35%
Central Appalachia	2	Room and Pillar	40%
Illinois Basin	3	Room and Pillar	40%
	4	Longwall	40%
Colorado Plateau	5	Longwall	33%

Table 8: Average Percent Rejects

For the purpose of this report, UGMMs in the Northern and Central Appalachian regions are projected to use a traditional cross-valley impoundment refuse facility. The embankment and basin capacities of impoundments are dependent on the nature of the surrounding terrain.[40] Due to its relatively flat landscape, the Illinois Basin uses a dike or bermed refuse impoundment. The Colorado Plateau's model refuse facility is a dry fill since plants in this region do not produce fine waste.

A preparation plant and refuse facility were located on each model underground mine map listed in Appendix B. After the sites were established, the lengths and classifications of streams affected by their development were assessed.

The analysis included in this report assumes that watersheds evaluated for refuse disposal have not been previously mined. Underground mining can impact impoundment structures by creating pathways for slurry to flow and cause subsidence that may adversely affect the stability and water-retaining properties

[40] Leonard, Joseph W. *Coal Preparation*. New York: The American Institute of Mining, Metallurgical, and Petroleum Engineers, INC, 1979 Print. page 16-41
National Research Council. *Coal Waste Impoundments: Risks, Responses, and Alternatives*. Washington, DC: The National Academies Press, 2002.

of the embankment. Likewise, auger or highwall miner openings in adjacent coal seams can also create embankment instability and potential conduits for slurry to travel. If underground mining exists, design challenges and construction costs for refuse disposal structures can substantially increase.

The criteria used to size the model refuse facilities presented in this report are general and intended only to approximate volumes of refuse structures and estimate impacted stream lengths. Volumes are based on typical reject rates from each corresponding UGMM. Actual designs of refuse structures would require site-specific data and detailed analysis that is beyond the scope of the assessments included in this report.

5. DISCUSSION AND RESULTS

Refuse facilities store waste material generated by the processing of raw coal. The objective of this report was to determine the total, equivalent impact of a refuse facility for each UGMM. Refuse produced, capacity, embankment slope, stream gradient, topography, and type of refuse facility (based on regional practices) were the major parameters used to locate and delineate these structures.

In 2012, four coal regions produced about 93% of the underground coal mined in the United States.[41] These regions are: Northern Appalachia (30%), Central Appalachia (23%), Illinois Basin (27%), and Colorado Plateau (13%). Each of the remaining coal regions yielded less than 4% of the total underground production. Based on their production levels, the four regions listed above were chosen for the evaluation of refuse disposal facilities.

5.1. Northern Appalachia

The Appalachian Basin is divided into three regions: Northern Appalachia, Central Appalachia, and Southern Appalachia. The Northern Appalachian region has the highest longwall mining production[42] and contains the second highest number of preparation plants in the United States.

Figure *10*[43] shows the number of plants in the Northern Appalachian Region (scale bar on the left). The percentages of U.S. plants, shown in light red, correlate to the scale bar of percentages on the right side of the figure. An average raw feed capacity was calculated to be approximately 1000 tons per hour (tph).

Production records from the top-producing Northern Appalachian mines indicate that the 21 top producing underground mines (greater than 1 million tons per year) produced 90 million short tons in 2012, with an average production per mine of 4.3 million tons. The remaining underground mines in the region produce approximately 13% of underground production in Northern Appalachia; however, these mines are not representative of a majority of production in the region. The representative mine for Northern Appalachia is a longwall operation producing approximately 4.6 million tons per year.

[41] MSHA 2012 Data and analysis by Energy Ventures Analysis, Inc (received April 16, 2013).
[42] Fiscor, Steve "U.S. Longwall Census," Coal Age, February 2012: 24.
[43] The red highlighted area in Figure 10 indicates the region currently being discussed. In this case, the region being discussed is the Northern Appalachian region.

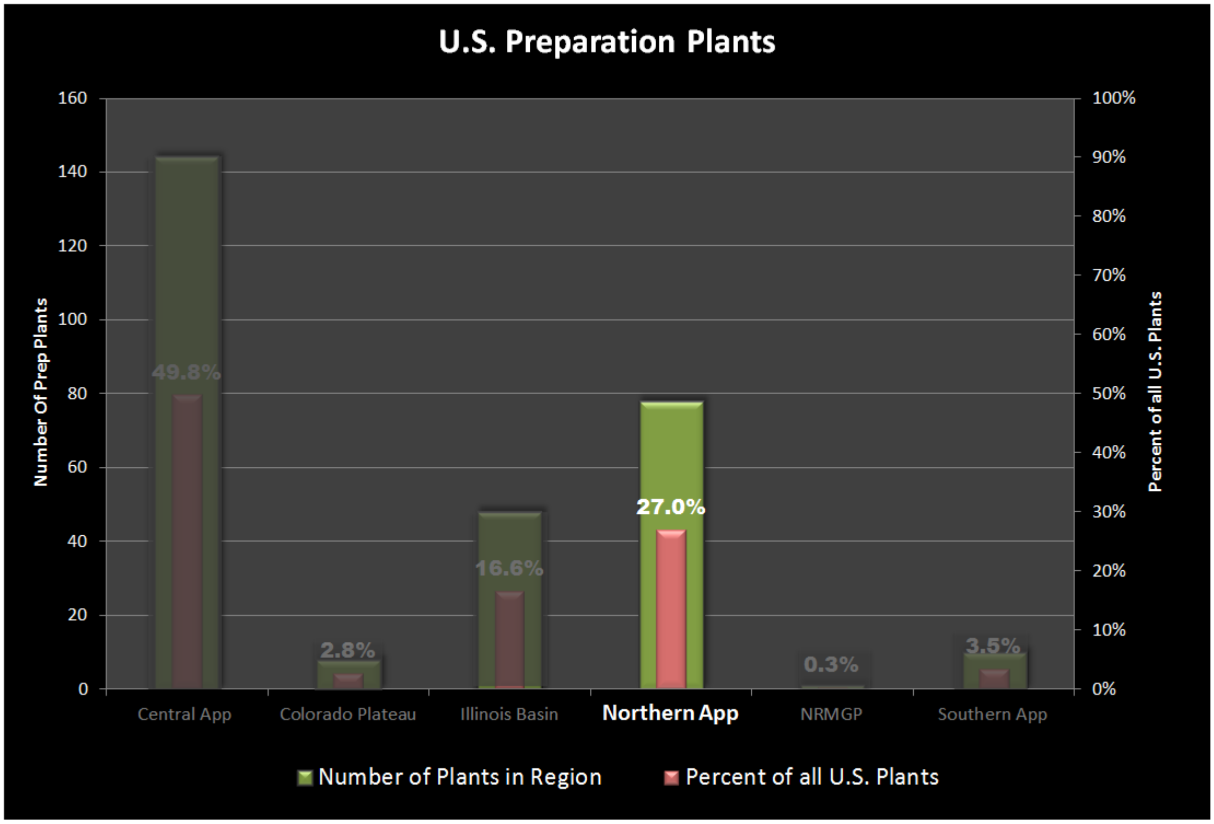

Figure 10: Northern Appalachian - Preparation Plants and Industry Percentages

The Northern Appalachian longwall model mine has a resource totaling about 84.7 million tons. Because the longwall method is more efficient than the room and pillar mining method, an 85% recovery factor was assumed. The total run of mine coal production from this mine is almost 72 million tons of coal over 15-1/2 years at a production rate of 4.6 million tons per year.[44]

The Northern Appalachian Region uses a typical cross-valley refuse impoundment containing about 14.4 million cubic yards and encompassing approximately 145 acres. The cross-valley embankment will be constructed of coarse material at a slope of 2-foot horizontal to 1-foot vertical with a 20-foot wide bench set at every 50-foot rise in elevation. The model impoundment for the Northern Appalachian Region is shown in Figure 11.

[44] Model mine details are from Appendix B.

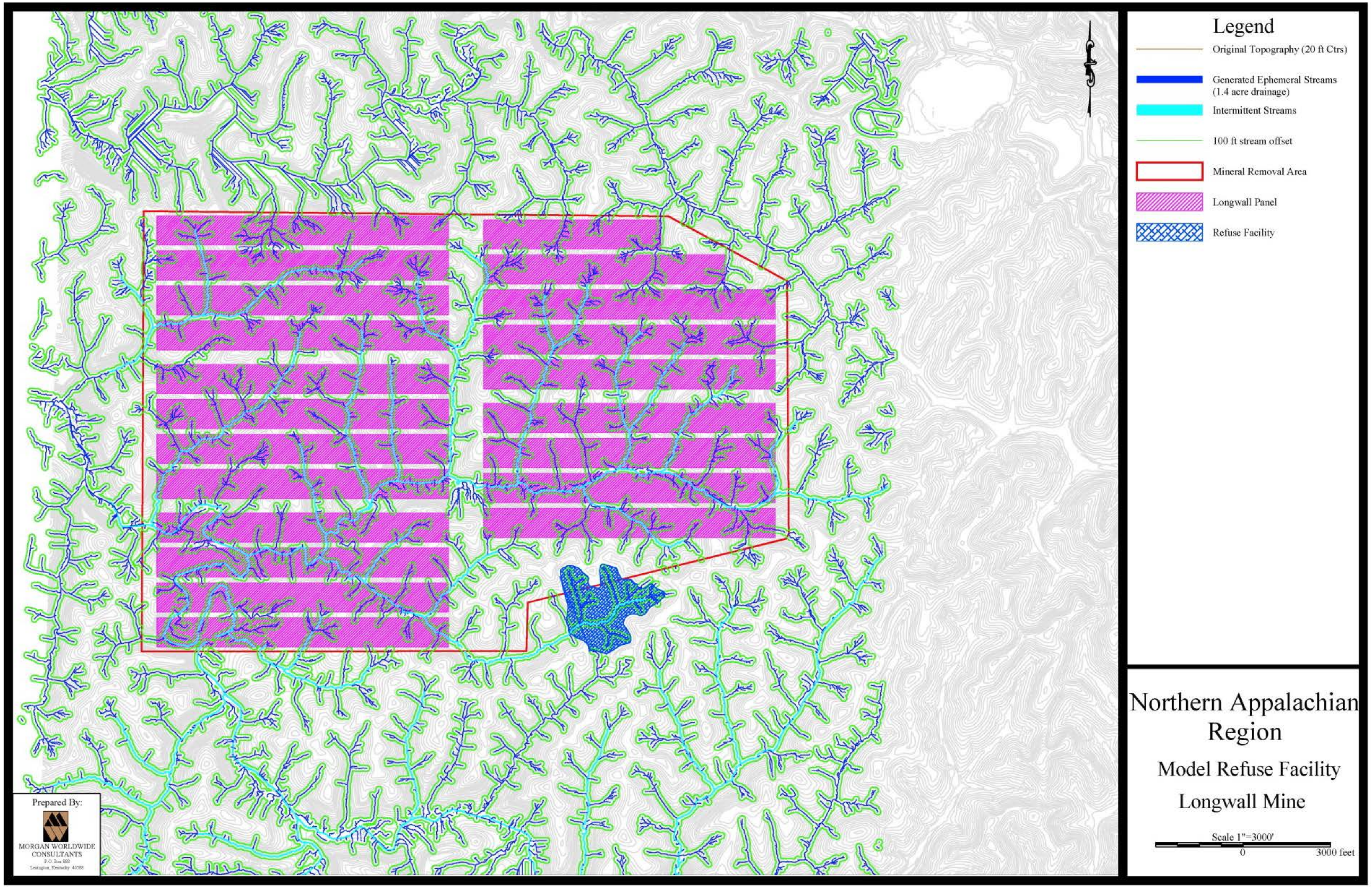

Figure 11: Northern Appalachian Model Plant and Coal Refuse Facility

The streams for this region were generated using drainage densities that are typical for the region. It was assumed ephemeral drainage requires 1.4 acres to form a stream channel. The drainage area of 1.4 acres was determined by examining a representative mine in the area[45]. The intermittent streams were identified using USGS National Hydrography. No perennial streams were impacted by the refuse facility.

5.1.1. Results

The lengths of impacted streams for the refuse facility are listed below.

- Ephemeral 10,542 ft
- Intermittent 3,529 ft
- Total 14,071 ft

Stream mitigation costs in this region were assumed to be $800 per foot[46] of stream disturbance. The stream mitigation cost applies to all stream types and does not vary based on stream class.

Alternatives 2 and 3 prohibit placement of refuse material in perennial streams. However no perennial streams are affected by the refuse facility. The total costs for the NAPP Longwall model mine are most influenced by the Stream Enhancement costs, which constitute over 90% of the costs for all Alternatives. Costs associated with action Alternatives 2 through 9 are shown in Table 9 below.

Northern Appalachian Longwall - Total Costs									
	Alt 1 (Base)	Alt 2	Alt 3	Alt 4	Alt 5	Alt 6	Alt 7	Alt 8	Alt 9
Stream Enhancement	$11,256,800	$11,256,800	$11,256,800	$11,256,800	$11,256,800	$11,256,800	$11,256,800	$11,256,800	$11,256,800
Reforestation	$0	$235,523	$235,523	$235,523	$235,523	$0	$235,523	$235,523	$0
Topsoil Salvage	$0	$406,118	$406,118	$406,118	$406,118	$0	$406,118	$406,118	$0
Redamation of Organics	$0	$31,393	$20,181	$20,181	$20,181	$0	$20,181	$20,181	$0
Total	$11,256,800	$11,929,834	$11,918,622	$11,918,622	$11,918,622	$11,256,800	$11,918,622	$11,918,622	$11,256,800

Table 9: Northern Appalachian Cost Comparison

5.2. Central Appalachia

The Central Appalachian Region is made up of Eastern Kentucky, Southern West Virginia, Southwest Virginia, and Eastern Tennessee. The coal is generally considered a high grade bituminous coal, which, depending on its quality, is sold as steam or metallurgical coal.[47] This region has experienced an extensive history of mining. Surface and underground mining have been employed on small and large scales, depending on the available capital, market demands, regulatory restraints, and other conditions. Previous mining has targeted seams that are the most economical and least challenging to recover. The remaining coal reserves in Central Appalachia are generally bounded by partially-mined coal seams, creating an increasingly difficult environment for extracting the remaining resources.

[45] The 1.4 acres of drainage area is from Appendix B.
[46] Cost per foot of stream ($800) is from Appendix B.
[47] McIlmoil, Rory; Hansen, Rory. *The Decline of Central Appalachian Coal and the Need for Economic Diversification.* Downstream Strategies, 2010.

Underground mining operations in Central Appalachia constitute about 8% of the overall U.S. coal production. These mines predominantly employ continuous methods and tend to be either large or small in size, with most of the operations consisting of smaller mines. About 220 underground mines, producing less than 200,000 tons per year, account for about 21% of the region's underground coal production. About ten mines, which produce more than one million tons per year, account for about 25% of the region's total underground production. The remaining 54% of underground production comes from mines producing coal at a rate of 200,000 tons per year to 1,000,000 tons per year.

The Central Appalachian Region contains nearly half of all preparation plants found in the review of preparation plants summarized in Section 3 of this report. See Figure 12.

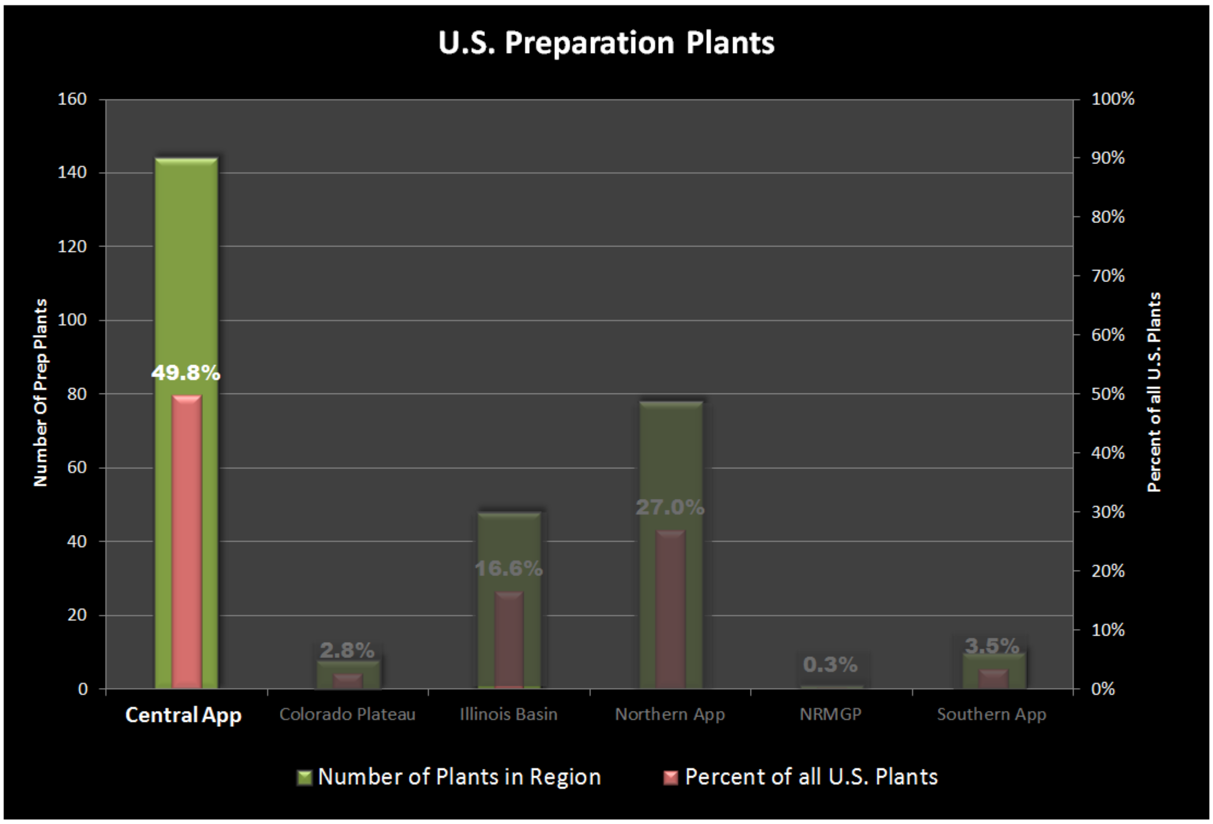

Figure 12: Central App - Preparation Plants and Industry Percentages

The Central Appalachian underground room and pillar model mine has an estimated coal resource of 4.2 million tons.[48] The model impoundment is designed to store refuse from the processing raw coal from this mine. The Central Appalachian model coal refuse impoundment has an estimated storage capacity of 1.0 million cubic yards and a surface area of about 12 acres. Like the Northern Appalachian model impoundment, it is a typical cross valley embankment with a 2:1 slope and 20-foot wide benches set at every 50-foot rise in elevation.

[48] Model mine details are from Appendix B.

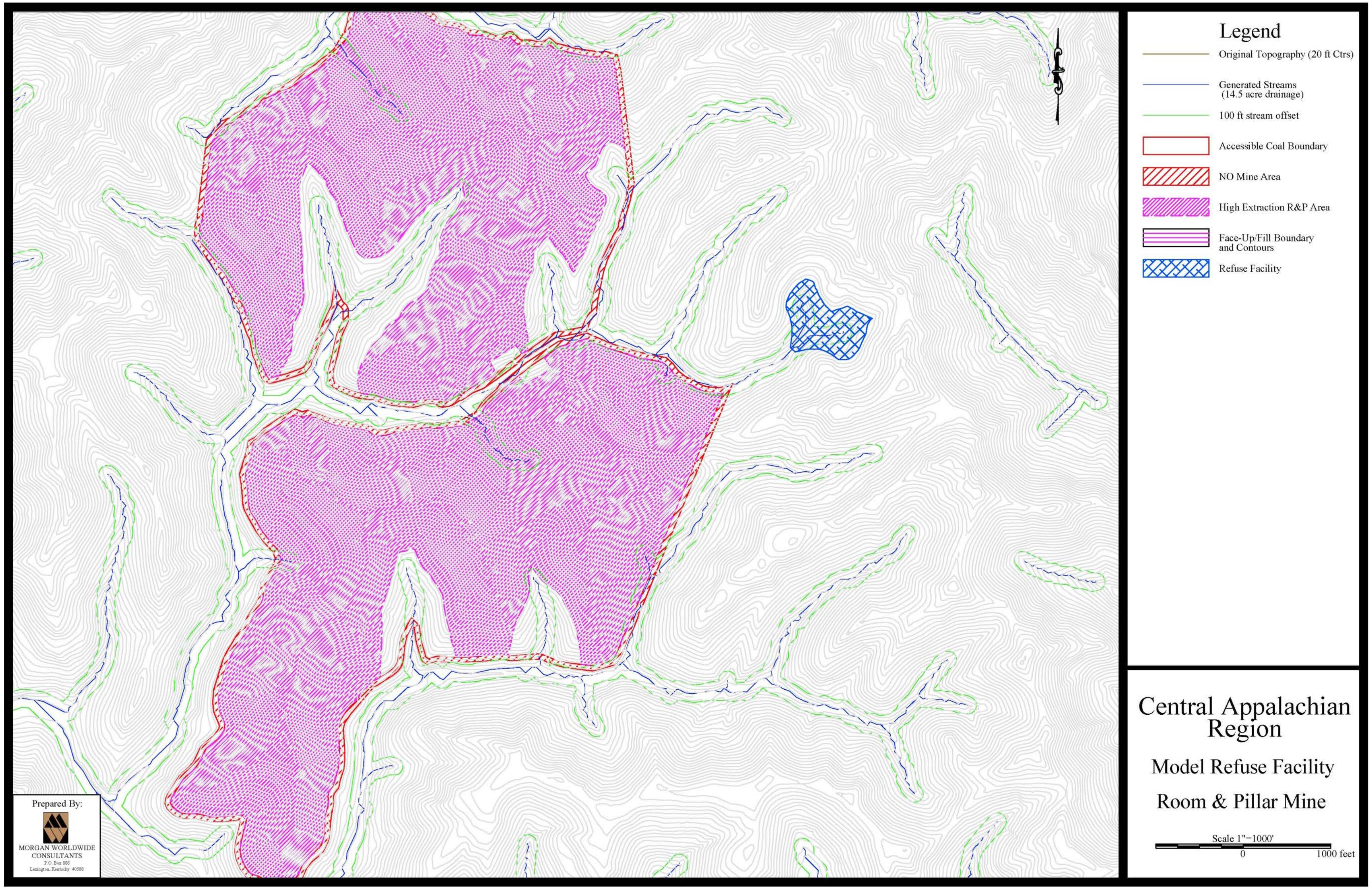

Figure 13: Central Appalachian Coal Refuse Facility – Room & Pillar Mine

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The Central Appalachian Regional streams were generated using drainage densities typical for the region. The ephemeral stream requires a drainage density of approximately 14.5 acres of drainage[49]. Intermittent streams in central Appalachia begin at about 20 acres of drainage on the up-dip side of the coal outcrop and begin at the outcrop on the down-dip side of the coal seam.[50]

5.2.1. Results

The lengths of impacted streams for the refuse facility are listed below.

- Ephemeral 391 ft
- Intermittent 863 ft
- Total 1,254 ft

The costs for stream mitigation in this region was assumed to be $800 per foot of stream[51] impacted. Stream mitigation costs apply equally to all stream types, regardless of their classification

Alternatives 2 and 3 prohibit placement of refuse material in perennial streams. However no perennial streams were affected by the Central Appalachian Region model refuse facility. The size of the refuse facility for the CAPP room and pillar mine is relatively small and, therefore, the Stream Enhancement costs are also small. Costs associated with action Alternatives 2 through 9 are shown in

Table 10 below.

Central Appalachian Room and Pillar - Total Costs									
	Alt 1 (Base)	Alt 2	Alt 3	Alt 4	Alt 5	Alt 6	Alt 7	Alt 8	Alt 9
Stream Enhancement	$1,003,200	$1,003,200	$1,003,200	$1,003,200	$1,003,200	$1,003,200	$1,003,200	$1,003,200	$1,003,200
Reforestation	$0	$18,888	$18,888	$18,888	$18,888	$0	$18,888	$18,888	$0
Topsoil Salvage	$0	$33,967	$33,967	$33,967	$33,967	$0	$33,967	$33,967	$0
Redamation of Organics	$0	$2,626	$1,688	$1,688	$1,688	$0	$1,688	$1,688	$0
Total	$1,003,200	$1,058,681	$1,057,743	$1,057,743	$1,057,743	$1,003,200	$1,057,743	$1,057,743	$1,003,200

Table 10: Central Appalachian Cost Comparison

5.3. Illinois Basin

The Illinois Basin region is set primarily in the state of Illinois but also extends into western Indiana and western Kentucky. Many of the coal seams in this region are overlain with glacial drift that varies from depths of 10 feet to over 200 feet in some areas. Extreme differences in coal elevations are created by the concave regional geometry. Despite the basin’s deformity, this region contains substantial deposits of recoverable coal that are greater than 42 inches in thickness.[52]

[49] The drainage density of 14.5 acres is from Appendix B.
[50] Svec, J.R., R.K. Kolka, and J.W. Stringer. University of Kentucky. Department of Forestry. Defining Perennial, Intermittent and Ephemeral Channels in Eastern Kentucky: Application to Forestry Best Management Practices. Elsevier B.V., 2005. Print.
[51] Cost per foot of stream ($800) is from Appendix B.
[52] Wade, A.B. United States . U.S. Geological Survey . USGS Assesses Coal in the Illinois Basin. Reston, VA: USGS, 2002. Web. <http://www.usgs.gov/newsroom/article.asp?ID=346#.Ub8nwufpB8E>.

Coal production in the Illinois Basin is dominated by underground mining, with 73% of its total production originating from underground mines. For operations using the room and pillar (R&P) mining method, the average production is approximately 2.1 million tons per annum. Most R&P mines in this region produce between 2 and 3 million tons per year. See Appendix B for more information.

Although only five longwall mines currently operate in the Illinois Basin (all in the state of Illinois), several more longwall operations are expected to be permitted in the next few years. The average longwall production in 2012 was 4.8 million tons, but recent reports indicate that future Illinois longwall operations will produce at least 6 million tons per annum.

As shown in Figure 14, the Illinois Basin contains nearly 50 processing facilities, which is about 17% of the total plants in the U.S.

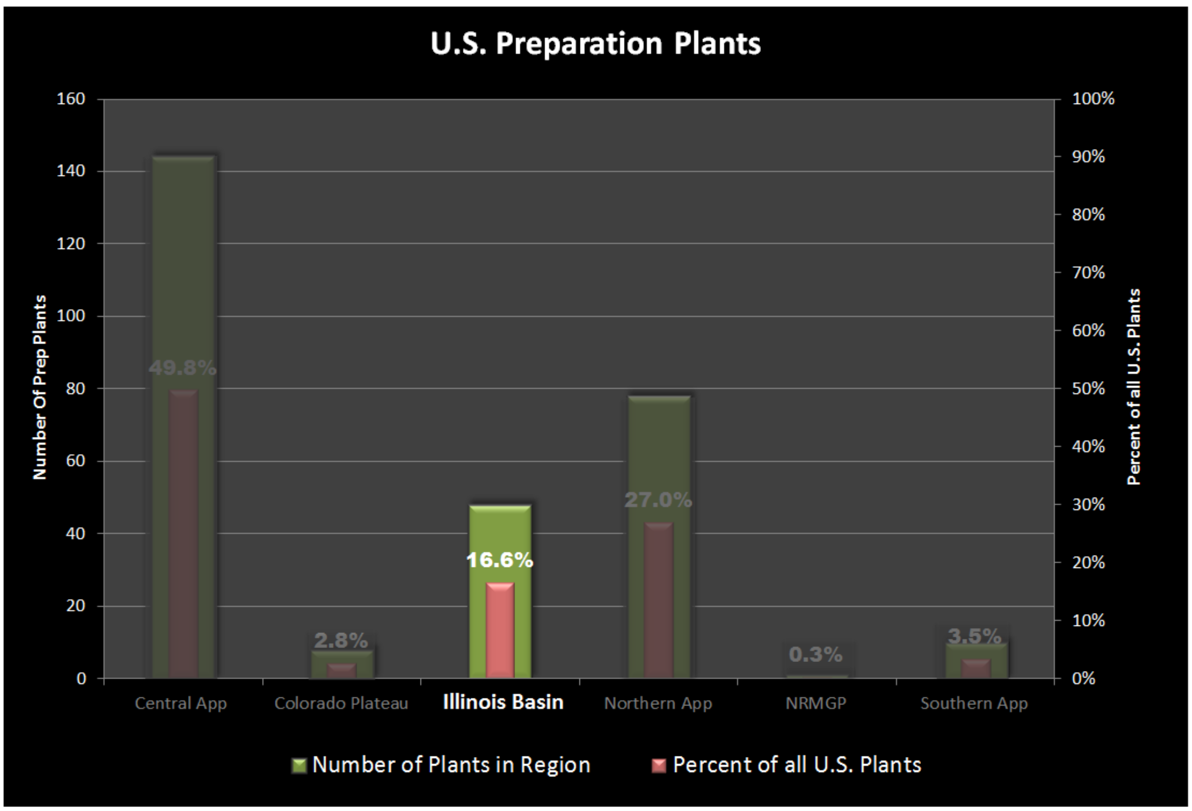

Figure 14: Illinois Basin - Preparation Plants and Industry Percentages

Two underground model mines have been established in the Illinois basin; one is a room and pillar mine, and the other is a longwall mine. The longwall mine will produce six million tons of coal per year from a coal seam ranging from 5.5 to 7.5 feet thick at a depth of cover of 380 to 600 feet.

The room and pillar mine covers about 4,100 acres and produces 2.1 million tons per year over approximately nine years, not including development and reclamation time. The mine operates in using the same model topography and coal seam information as the longwall mine; therefore, the coal ranges between 5.5 and 7.5 feet thick. A model refuse facility was sized for each mine. See Figure 15 and Figure 16.

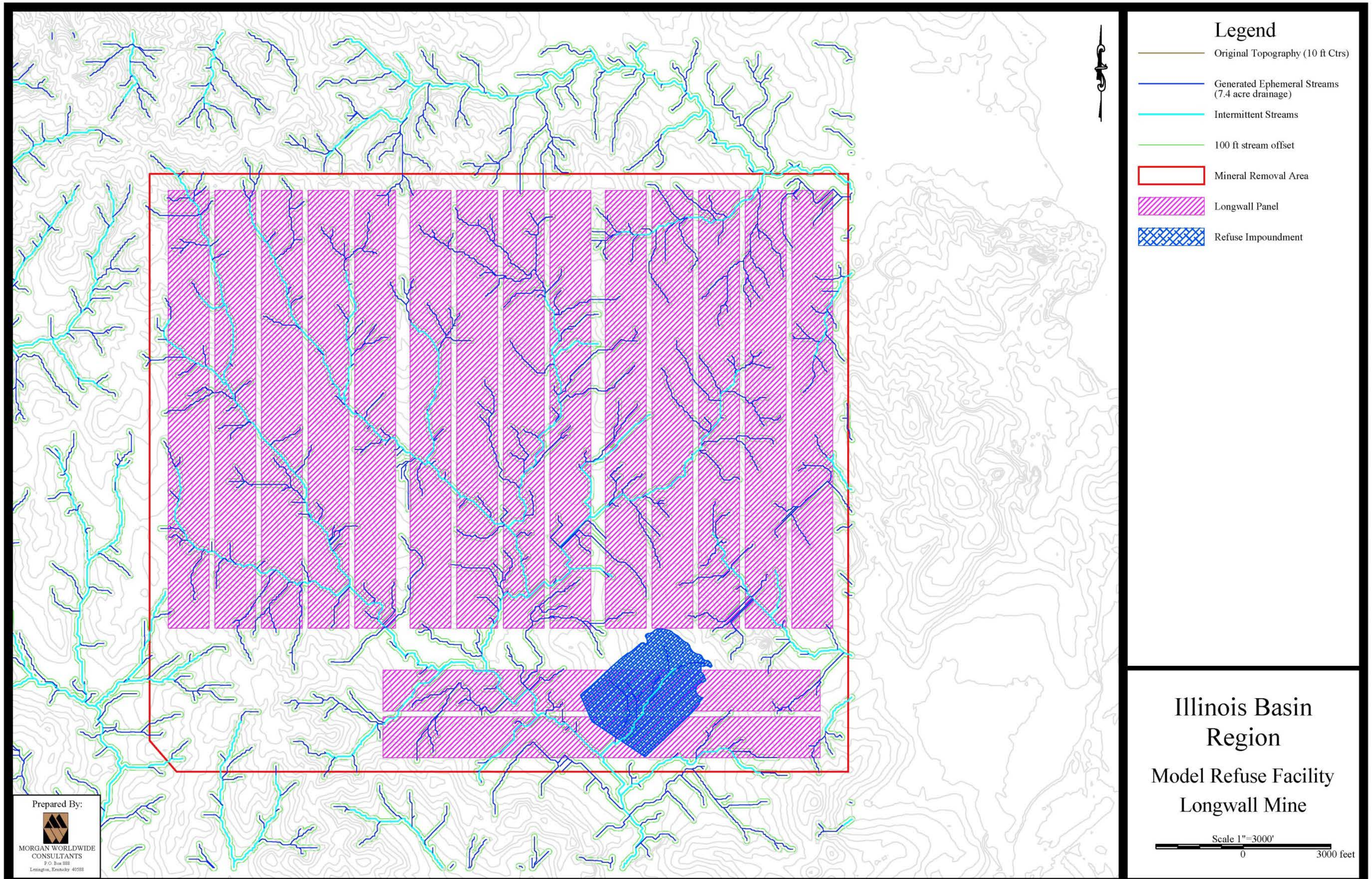

Figure 15: Illinois Basin Coal Refuse Facility – Longwall Mine

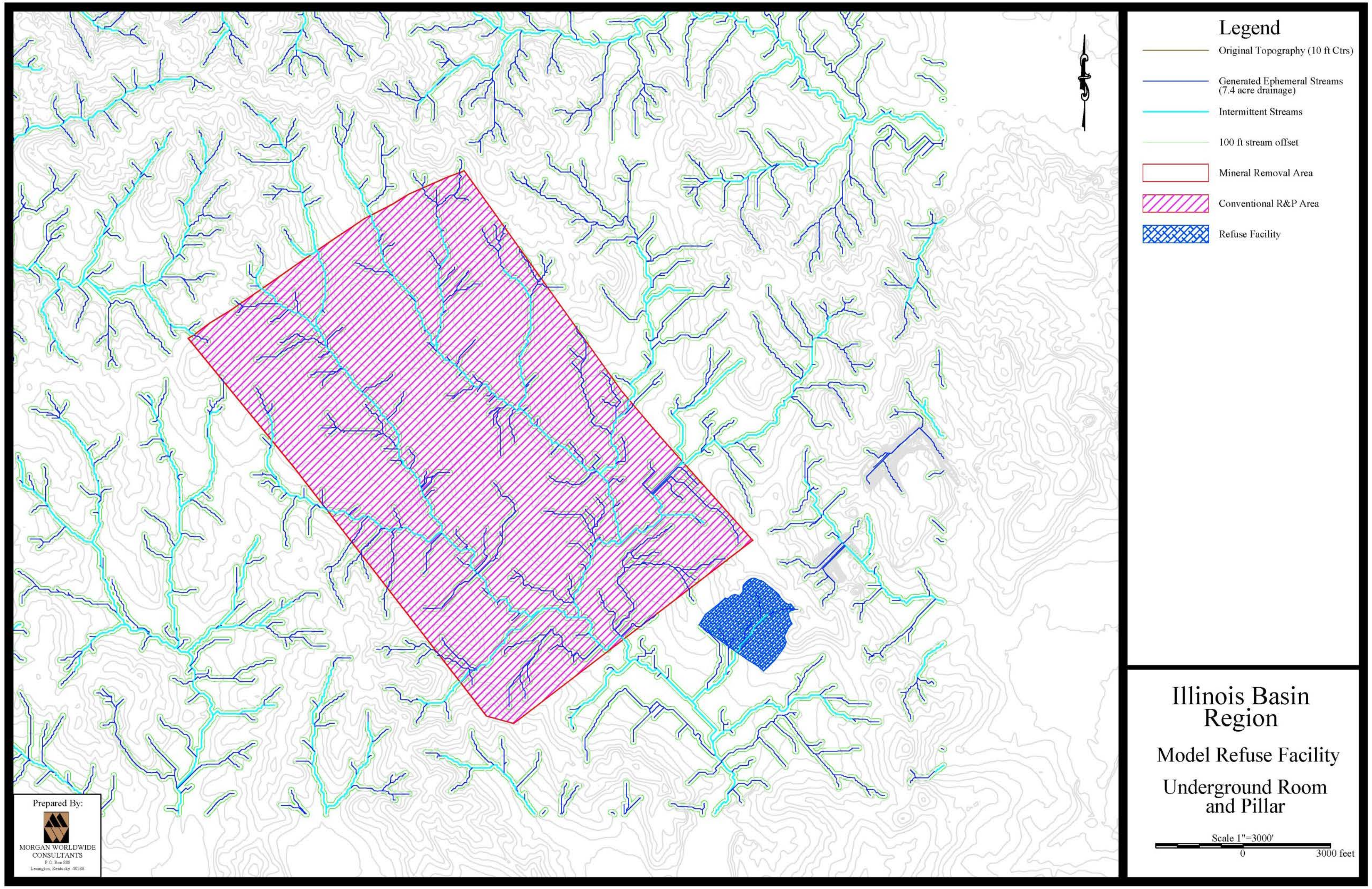

Figure 16: Illinois Basin Coal Refuse Facility - Room & Pillar Mine

After a review of refuse facilities in this region, a berm style impoundment was selected. For the room and pillar mine, the model refuse facility contains about 4.5 million cubic yards of storage and has a surface disturbance area of about 45 acres. For the longwall mine, the model refuse facility contains about 24.3 million cubic yards of storage and has a surface disturbance area of about 134 acres. Both refuse facilities have 2:1 sloped embankments with 20-foot wide benches set at every 50-foot rise in elevation.

Ephemeral streams for the Illinois Basin shown in Figure 15 were generated using a drainage density of 7.4 acres. The intermittent and perennial streams were identified using the USGS National Hydrography Dataset since there was no other information on groundwater flow and intermittent streams that have less than 1 square mile of drainage.[53]

5.3.1. Results

The lengths of impacted streams for the Illinois Basin refuse facilities are listed below.

Refuse Facility - Room & Pillar Mine

- Ephemeral 2,112 ft
- Intermittent 299 ft
- Total 2,411 ft

Refuse Facility - Longwall Mine

- Ephemeral 5,173 ft
- Intermittent 1,756 ft
- Total 6,929 ft

The stream mitigation costs in the Illinois Basin region were assumed to be $300 per foot of stream disturbance[54] and these costs applies for all types of streams and do not vary based on different stream classes.

Two alternatives (2 and 3) restrict placement of refuse material in perennial streams. However no perennial streams were affected from the Illinois Basin Region refuse facility. Costs associated with action Alternatives 2 through 9 are shown in Table 11 and Table 12 below.

[53] 30 C.F.R. § 701.5 (2011)
[54] The $300 per foot of stream value is from Appendix B.

Table 11: Illinois Basin R&P Cost Comparison

Illinois Basin Longwall - Total Costs									
	Alt 1 (Base)	Alt 2	Alt 3	Alt 4	Alt 5	Alt 6	Alt 7	Alt 8	Alt 9
Stream Enhancement	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700
Reforestation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Topsoil Salvage	$0	$0	$0	$0	$0	$0	$0	$0	$0
Redamation of Organics	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700	$2,078,700

Table 12: Illinois Basin Longwall Cost Comparison

5.4. Colorado Plateau

The Colorado Plateau includes Western Colorado, Utah, New Mexico, and Arizona. The majority of underground mining in the Colorado Plateau occurs in the Uinta Basin, which spans the northeast portion of Utah and Colorado. Average underground mine production in the Colorado Plateau is 2.5 million tons per year. However, smaller mines significantly influence this average, with 39% of the underground mines producing 8% of the underground coal. Furthermore, an assessment of top producing Colorado Plateau mines indicates that the eleven largest underground mines totaled 42.3 million short tons with an average production per mine of 3.9 million tons. Although the average for all underground mines is 2.5 million, an average production of 3.9 million would better represent the major production in the region.

The Colorado Plateau contains only about 3% of all preparation plants in the United States as shown in Figure *17*.

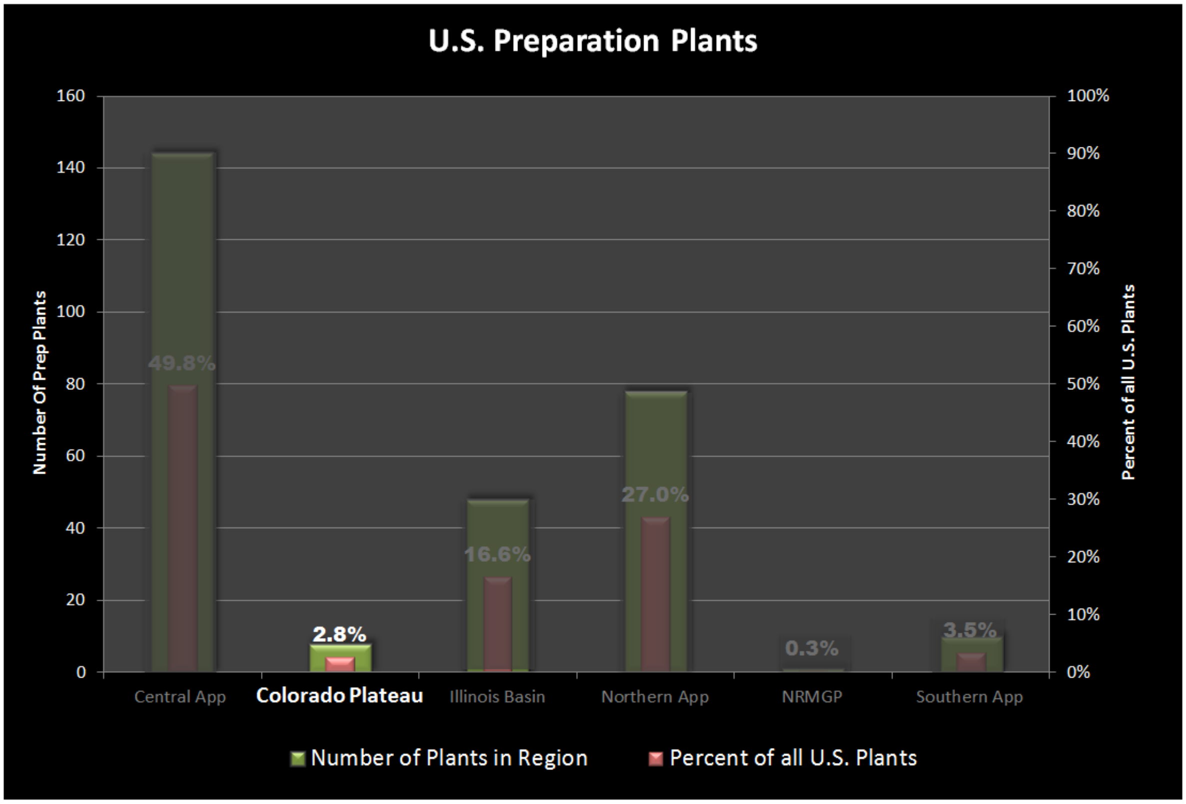

Figure 17: Colorado Plateau - Preparation Plants and Industry Percentages

The underground longwall model mine in the Colorado Plateau has a coal resource of approximately 27.9 million tons. This mine has a high mining recovery rate at approximately 85% and an expected lifetime run-of-mine coal output of approximately 23.7 million tons.[55]

The model refuse facility in the Colorado Plateau Region has a total footprint of about 23 acres with a storage capacity of approximately 5.4 million cubic yards of material. The type of facility is a dry fill, as shown in Figure 3, with no impounding of water or slurry. The refuse fill has 2:1 slopes and a 20-foot wide bench at every 50-foot change in elevation. The ephemeral streams in the Colorado Plateau Region were generated using a drainage area of approximately 7 acres[56]. Current federal regulations state that an intermittent stream is defined by one square mile of drainage area or surface flow generated during parts of the year by the groundwater table[57].

[55] Details concerning the model mine are from Appendix B.
[56] The drainage area of 7 acres is from Appendix B.
[57] 30 C.F.R. § 701.5 (2011)

Figure 18 shows the area used for the refuse facility and also outlines the mineral removal area of the Colorado Plateau underground model mine.

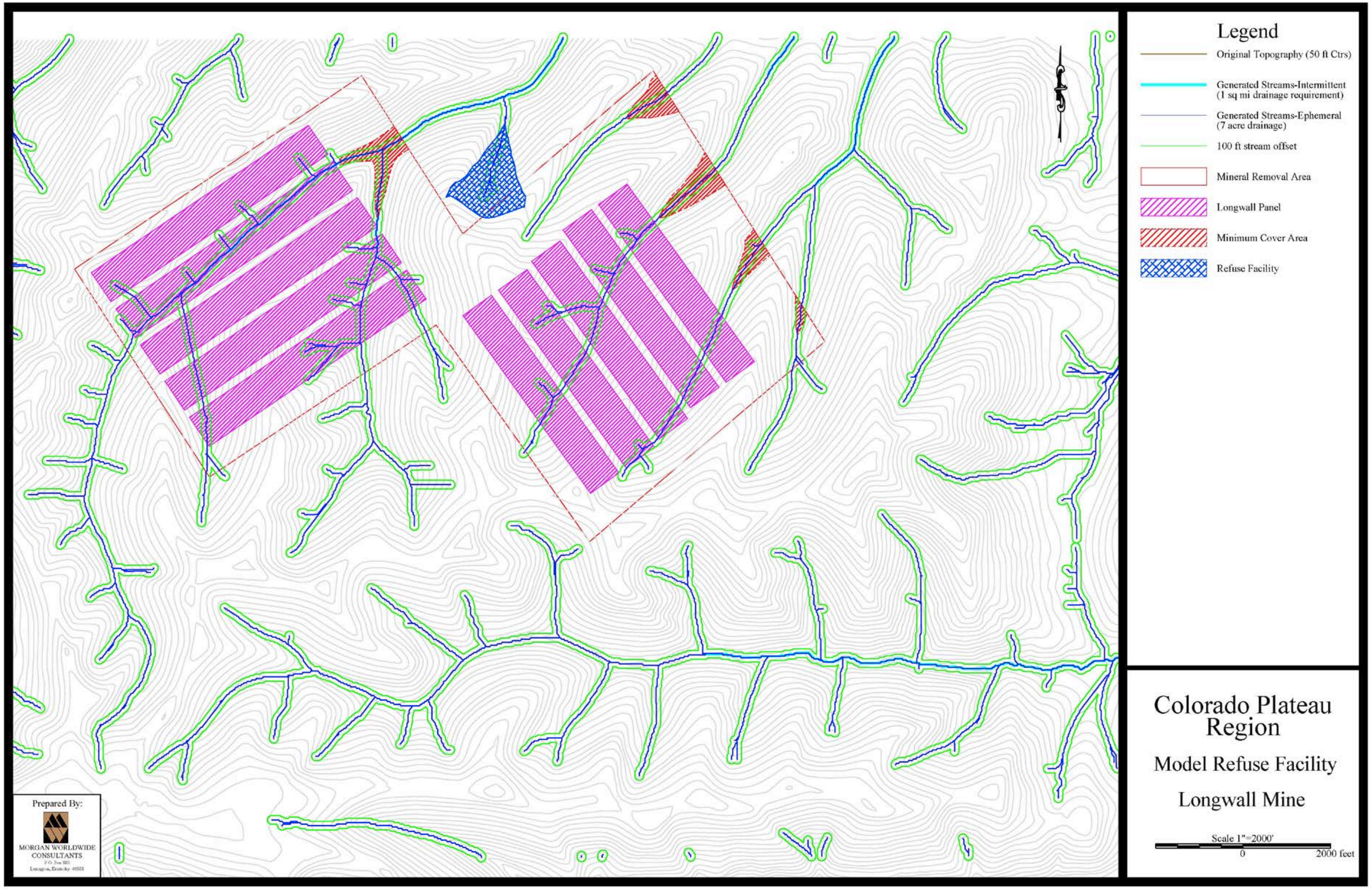

Figure 18: Colorado Plateau Coal Refuse Facility – Longwall Mine

5.4.1. Results

The lengths of impacted streams for the Colorado plateau refuse facility are shown below.

- Ephemeral 2,080 ft
- Intermittent 0 ft
- Total 2,080 ft

The stream mitigation costs in the Colorado Plateau were assumed to be $300 per foot of disturbed stream[58]. This cost applies to all types of streams and does not vary based on stream type.

Alternatives 2 and 3 prohibit placement of refuse material in perennial streams. However no perennial streams were affected from the Colorado Plateau model plant or refuse facility.

Costs associated with Alternatives 1-9 are shown in Table 13 below.

Colorado Plateau Longwall - Total Costs									
	Alt 1 (Base)	Alt 2	Alt 3	Alt 4	Alt 5	Alt 6	Alt 7	Alt 8	Alt 9
Stream Enhancement	$629,100	$629,100	$629,100	$629,100	$629,100	$629,100	$629,100	$629,100	$629,100
Reforestation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Topsoil Salvage	$0	$123,545	$123,545	$123,545	$0	$0	$123,545	$123,545	$0
Redamation of Organics	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$629,100	$752,645	$752,645	$752,645	$629,100	$629,100	$752,645	$752,645	$629,100

Table 13: Colorado Plateau Cost Comparison

6. CONCLUSIONS

The purpose of this report is to evaluate coal refuse disposal and preparation facilities for the underground model mines presented in Appendix B. This evaluation is based on the criteria specified in the six proposed action alternatives. Since the UGMMs are not connected with larger mining complexes, each one is considered a self-contained operation. Therefore, for each UGMM, preparation and waste disposal facilities are required to convert its raw coal to a marketable product. The locations and types of refuse facilities included in this report are based on typical practices in each coal region. After the boundaries of these sites were established, the length and classification of streams affected by the construction of these facilities were assessed.

6.1. Preparation and Refuse Facilities

Data was gathered for preparation plants and refuse facilities in all applicable coal regions. From this information, typical refuse facility types were determined. Subsequently, a model refuse facility was sized for each UGMM, and the lengths of impacted streams were determined. Based on the analysis included in this report, the alternatives will have little or no effect on the cost of coal refuse disposal relevant to stream mitigation for the UGMMs. A conclusion of no impacts pertains to those coal refuse impoundments that are located away from perennial streams and comply with all other relevant provisions. Table 14 lists the cost differentials by region for the model coal refuse facilities.

[58] The $300 per foot of stream value is from Appendix B.

Cost Condition	Alternative	Appalachian Region		Colorado Plateau	Illinois Basin	
		CAPP R&P	NAPP LW	LW	R&P	LW
Base Case	Alt 1	$1,003,200	$11,256,800	$629,100	$723,300	$2,078,700
Change in Cost From Alt 1	Alt 2	$55,481	$673,034	$123,545	$0	$0
	Alt 3	$54,543	$661,822	$123,545	$0	$0
	Alt 4	$54,543	$661,822	$123,545	$0	$0
	Alt 5	$54,543	$661,822	$0	$0	$0
	Alt 6	$0	$0	$0	$0	$0
	Alt 7	$54,543	$661,822	$123,545	$0	$0
	Alt 8	$54,543	$661,822	$123,545	$0	$0
	Alt 9	$0	$0	$0	$0	$0

Table 14: Difference in Cost per Region

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APPENDIX F: COAL MARKET MODELING ANALYSIS

APPENDIX F.

Methodology for Energy Market Modeling in Support of Stream Protection Rule

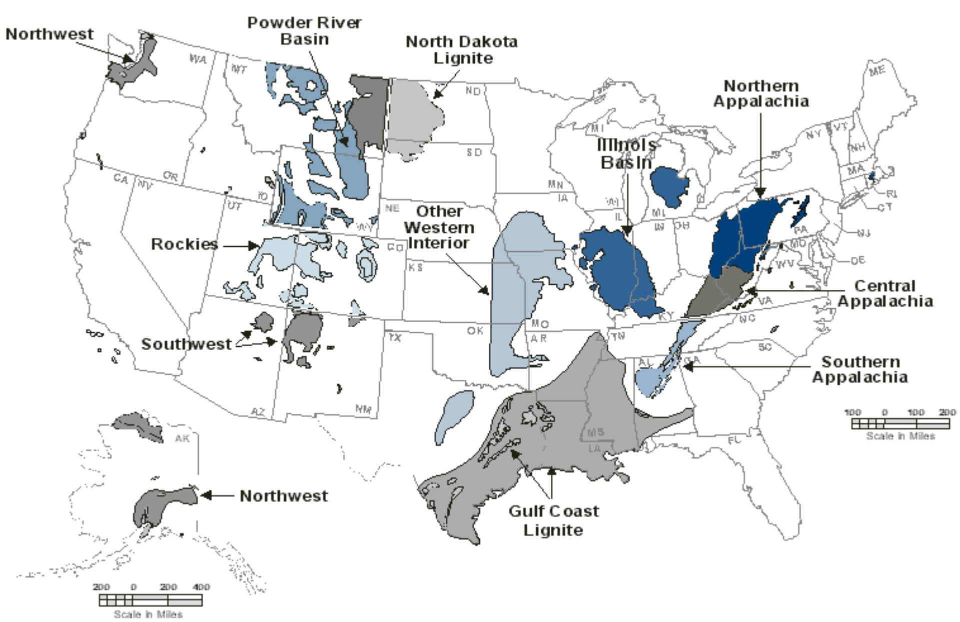
Overview

The Office of Surface Mining (OSM) is considering the development of a revised Stream Protection Rule (SPR). As part of its analysis, OSM has engaged the services of Industrial Economics ("IEc") to prepare the Regulatory Impact Analysis. Morgan Worldwide ("Morgan") and Energy Ventures Analysis, Inc. ("EVA") are sub-contractors to IEc. Morgan has been engaged to evaluate the impact of the alternative SPR's on model mine costs. EVA has been engaged to evaluate the impact of the model mine costs effects on the overall supply, demand and price for coal. This memorandum explains the EVA methodology for its analysis.

Background on the U.S. Coal Industry

Coal is produced in multiple supply regions throughout the country (Exhibit 1). Five of the supply regions are key as they are substantial producers and they produce coal that is consumed both in local and non-local markets. The remaining regions primarily produce coal for local consumption.

Exhibit 1. U.S. Coal Supply Regions



The five key supply regions are as follows:

- **Northern Appalachia** which includes all bituminous coal production in the states of Pennsylvania, Ohio and Maryland and production in the northern part of West Virginia. Production in Northern Appalachia is currently dominated by the Pittsburgh seam, a large reserve of thick coal which lies in a basin that runs through southwest Pennsylvania, northern West Virginia, and eastern Ohio. The dominance of the Pittsburgh seam is attributed to longwall mining technology which is ideal for the consistent five to eight foot seam height and good roof and floor of the Pittsburgh seam. Both steam and metallurgical coals are produced in Northern Appalachia, although the highest quality metallurgical coals have largely been mined out.

- **Central Appalachia** which includes coal production from eastern Kentucky, southern West Virginia, Virginia, and Tennessee. This is the principal source of low sulfur bituminous coal in the United States and is used for power generation, metallurgical coke production and industrial boilers. At one time, the largest coal producing region in the U.S., production has fallen considerably from its peak of 291 million tons in 1990. Production fell from 234 million tons in 2008 to 195 million tons in 2009 as the combined impacts of the global economic recession, low natural gas prices, and the retrofitting of scrubbers on coal-fired power plants converged to lower demand. Production fell further in 2012 and 2013 as natural gas displacement, additional coal plant retirements, and additional switching by utilities at their newly retrofit power plants from Central Appalachian coal to higher sulfur coals reduced demand.

- The **Illinois Basin** which consists of the coal producing areas in Illinois, Indiana and West Kentucky. The coals in the Illinois Basin are produced from the same geological formation. The coal is bituminous with 10,000 to 12,500 Btu per pound and mostly over two percent sulfur. There are pockets of low sulfur coals in Indiana and Illinois but virtually no low sulfur coal in West Kentucky. Recent development of large, low cost mining operations has increased the supply and improved the competitiveness of the coal. Demand for Illinois Basin coal has been increasing because the retrofit of scrubbers on a significant amount of generating capacity in the eastern U.S. has allowed for the use of higher sulfur coals and because of increased exports.

- The **Rockies** which is a diverse set of producing areas, all of which have bituminous low sulfur coals including the San Juan Basin, Colorado, Utah, southern Wyoming, central Montana and the Raton Basin. Development of this supply region has been limited by demand. It has been difficult for western bituminous coals to compete in distant markets and Powder River Basin coals compete in local markets. Its primary non-local market is non-scrubbed power plants which need low sulfur, bituminous coals. As these plants are either expected to be retired or retrofit with pollution control equipment, demand for Rockies coal in non-local markets will decline. Rockies production is experiencing some success in expanding overseas markets.

- The **Powder River Basin** which is a huge deposit of sub-bituminous coal lying in northern Wyoming and southeast Montana. The Powder River Basin is divided into three areas, each with its own characteristics.

- **Gillette:** The Gillette area mines produce coal from the eastern outcrop of the Wyodak coal-bed near Gillette, Wyoming. The Gillette area itself is generally divided into three areas: South Basin, Central Basin, and North Gillette which vary by quality. The highest Btu mines are in the South Basin; the lowest in North Gillette. This area accounts for most of the production from the Powder River Basin.

- **Tongue River:** The Tongue River mines produce coal from the higher-Btu Anderson-Deitz coal seams found in low stripping ratios in the area from Sheridan, Wyoming through Decker, Montana. Only two mines are currently active in the Tongue River: Decker and Spring Creek, both of which are in Montana.

- **Colstrip:** The Colstrip mines produce coal from the thick Rosebud-McKay seams mined near Colstrip, Montana. Only two mines are currently active in the Colstrip area: Absaloka and Rosebud. The Rosebud coal moves by conveyor to the adjacent Colstrip power plant.

Coal production in the U.S. in 2013 was just under 1.0 billion tons. Coal production has ranged between 1.0 and 1.2 billion tons per year over the last 10 years (Exhibit 2).

Exhibit 2. U.S. Coal Production (Million Tons)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Northern Appalachia	133.3	138.3	134.3	131.9	135.2	126.1	129.1	131.2	124.6	121.7
Central Appalachia	232.2	235.4	236.1	225.6	233.4	194.6	184.2	182.7	147.2	127.7
Alabama	22.3	21.3	19.0	19.6	20.4	18.7	20.1	19.1	19.6	18.4
Appalachia Total	**387.9**	**395.0**	**389.5**	**377.2**	**389.0**	**339.4**	**333.4**	**333.0**	**291.4**	**267.9**
Illinois Basin	90.9	92.8	94.7	96.1	99.2	102.5	105.1	115.9	127.2	131.8
East Total	**478.8**	**487.8**	**484.2**	**473.3**	**488.2**	**441.9**	**438.5**	**448.8**	**418.6**	**399.6**
Powder River Basin	421.0	430.0	472.2	479.5	496.0	455.7	468.4	462.6	419.1	407.6
Rockies	87.3	87.6	86.2	84.9	81.5	74.9	70.8	74.5	74.1	71.7
Lignite	83.5	84.0	84.2	78.5	75.7	72.5	78.9	81.1	78.9	77.0
Southwest	28.4	29.8	23.6	23.4	24.0	22.4	20.5	20.0	20.1	20.9
Interior	8.1	7.9	5.3	2.4	2.0	1.6	1.6	1.8	1.6	1.6
West Total	**628.3**	**639.2**	**671.5**	**668.7**	**679.1**	**627.1**	**640.3**	**639.9**	**593.7**	**578.8**
Alaska	1.5	1.5	1.4	1.3	1.5	1.8	2.2	2.1	2.1	1.6
Anthracite	1.7	1.7	1.5	1.5	1.7	1.7	1.7	2.2	2.4	2.1
U. S. Total	**1,110.4**	**1,130.1**	**1,158.6**	**1,144.9**	**1,170.5**	**1,072.6**	**1,082.6**	**1,093.1**	**1,016.7**	**982.0**

As shown above, during this period there has been inter-regional switching primarily as a result of the decline in production from Central Appalachia and an increase in production from the Illinois Basin. The decline in Central Appalachian coal production reflects its relatively higher costs and declining demand from the utility sector and other domestic markets. The increase in the Illinois Basin coal production reflects new low cost production combined with it displacement of other coals in existing power plants newly retrofit with pollution control equipment. The Powder River Basin has had a fluctuating decade with production increasing from 421 million tons in 2004 to 496 million tons by 2008 and then falling to 408 million tons in 2013. The initial increase reflected its growth in coal generation. The declines at the end of the period reflect a combination of plant retirements, coal to gas switching (in 2012) and poor railroad performance (in 2013).

Coal production declined by about 100 million tons in 2009, largely as a result of the global financial crisis. The decline was concentrated in Central Appalachia and the Powder River Basin, both of which lost about 40 million tons of demand in 2009 compared to 2008. Total Domestic production in 2012 declined by about 74 million tons, primarily as a result of reduced utility demand as low gas prices resulted in gas dispatching ahead of coal in some markets. Gas prices fell as a result of a very mild 2011/2012 winter combined with increased shale gas production. While coal generation increased in 2013, production in 2013 only partially recovered due to a large drawdown in the inventories that had ballooned in 2012.

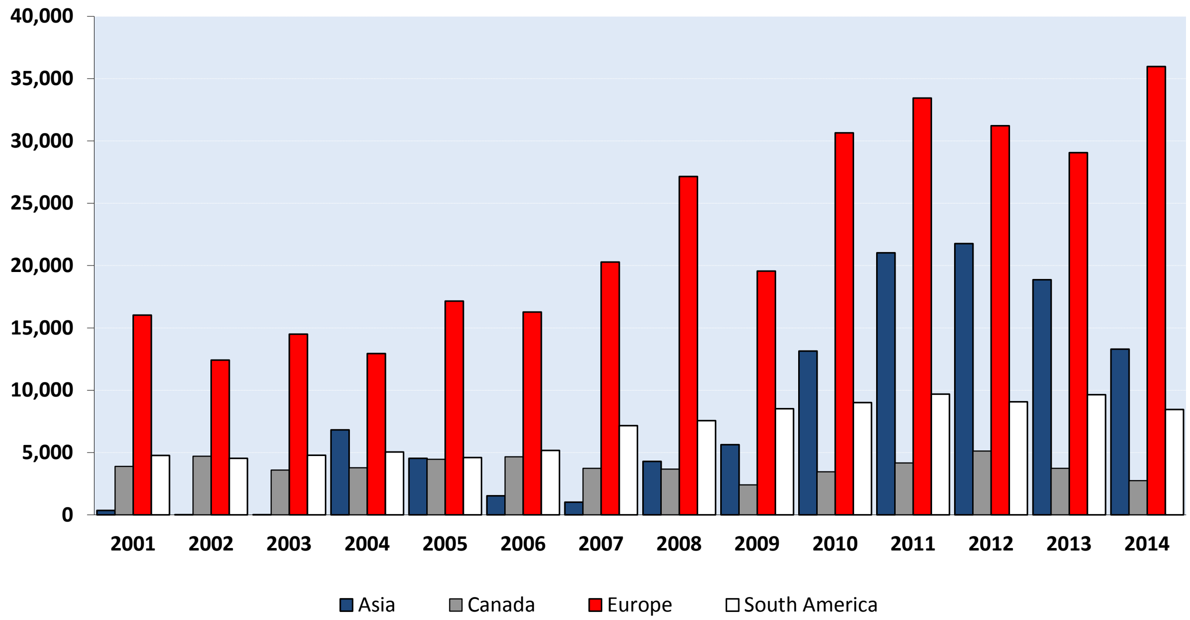
The primary market for U.S. coals is the domestic power industry. In 2013, utility generation accounted for over 80 percent of the domestic coal market (Exhibit 3). U.S. utility coal demand over the last three years has been affected by natural gas. The increased supply of natural gas from new shale plays has resulted in lower natural gas prices and significant displacement of coal-fired generation by natural-gas fired generation. The displacement has been greatest where coal generation is relatively high-cost, which is primarily generation from plants fired by low sulfur bituminous coals in markets remote from the coal supply sources.

Exhibit 3. U.S. Coal Demand (Million Tons)

	2013
Domestic	
Electric Power Burn	857.6
Consumer stock change	*(43.4)*
Electric Power Receipts	814.3
Coke Ovens	21.1
Industrial/Commercial	45.0
Total Domestic	**880.4**
Export	
Export metallurgical	61.2
Export steam	55.9
Total Exports	**117.1**
Total Demand	**997.5**

The export market has shown substantial growth in recent years driven by strong global demand. The U.S. is one of the three traditional sources of supply of metallurgical coals and has benefitted from the strong global demand for this product, particularly in the Pacific market. Australia is by far the largest source of metallurgical coal exports, typically accounting for about 60 percent of the market. The U.S. and Canada are a distant second and third. Europe continues to be the largest market for metallurgical coals. The relatively strong export market for U.S. metallurgical coals during the 2010 through 2013 period was due also to growth in exports to the Asian market.

Exhibit 4. Annual U.S. Metallurgical Coal Exports by Destination (1,000 Tons)



2014 is annualized from YTD

Outlook for U.S. Coal Industry

The impact of the SPR is not based upon the current market for U.S. coal but a function of the expected future markets for coal with and without the SPR. As a result, the establishment of a baseline forecast is a prerequisite to the evaluation of the effects of the SPR.

The baseline forecast reflects a number of assumptions critical to the outlook for future demand for U.S. coals. The major assumptions are described below.

Electricity Demand

The electricity demand growth forecast is derived from expectations for economic growth combined with the outlook for each sector (Exhibit 5). The forecast assumes continued but slower growth in demand in the residential and commercial sectors as a result of new lighting standards and improvements to energy efficiency in consumer electronics. After a modest rebound in industrial electricity demand, the forecast assumes declining industrial demand after 2015 due to continued losses in manufacturing capacity.

Exhibit 5. Electricity Demand Growth Forecast (Average Annual Percent Change), Baseline Forecast

	2011-2015	2016-20202	2012-2025	2026-2030	2031-2035
Total	0.4%	1.1%	0.9%	0.9%	0.9%
Residential	-0.5%	0.5%	0.6%	1.0%	1.1%
Commercial	0.3%	0.9%	1.0%	1.1%	1.3%
Industrial	2.0%	2.1%	1.0%	0.4%	0.2%
Other	5.0%	3.3%	2.4%	4.2%	4.3%
GNP	2.7%	0.2%	1.8%	1.8%	1.9%

New Environmental Rules Affecting Utility Generation

Several new environmental regulations are expected to affect utility coal generation during the forecast period. On July 6, 2011, EPA published the Cross-State Air Pollution Rule ("CSAPR") which replaced the Clean Air Interstate Rule ("CAIR"). CSAPR is the renamed and final version of the Clean Air Transport Rule (CATR) that EPA proposed in July 2010. There were numerous legal challenges to CSAPR primarily as a result of the significant changes from the CATR proposal including the accelerated compliance period. On December 30, 2011, the D.C. Circuit Court of the U.S. Court of Appeals granted a stay. On August 21, 2012, the D.C. Circuit Court vacated CSAPR and remanded the proceeding to EPA keeping CAIR in place. EPA sought Supreme Court review on the grounds that the D.C. Circuit decision exceeded the court's statutory authority and was inconsistent with court precedent. On April 29, 2014 the Supreme Court partially reversed the lower court. On June 26, 2014 EPA asked the D.C. Circuit to lift its stay of the rule. While the stay has not yet been lifted, it has limited impact as a result as compliance with the Mercury and Air Toxics Standard will be sufficient for compliance with CSAPR.[1]

In March 2011, EPA proposed national standards for mercury and other toxic air pollutants from power plants. The proposal was required under a court-imposed deadline that also requires a final rule be published by November 2011 and utility compliance by November 2014. The proposed air toxics rule requires Maximum Achievable Control Technology ("MACT") on every coal plant. Unlike the rule it replaced[2], the Utility MACT Rule falls under Section 112 of the Clean Air Act. As such, a maximum emission rate will be established for each plant with no trading between plants. All coal- and oil-fired plants greater than 25 MW will be regulated. The final rule for mercury and air toxics standards (now referred to as MATS) was issued on December 16, 2011. Emission rate limitations were established for three categories of air toxics: mercury, acid gases (hydrogen chloride, hydrogen fluoride and hydrogen cyanide) and heavy metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium). The new emission rates must be met within four years from its publication in the

[1] There may be a few plants who had delayed compliance with MATS that could be affected if CSAPR is reinstated according to its original timetable.

[2] This rule is replacing the Clean Air Mercury Rule which was vacated in 2008 in part because it was non-compliant with Section 112.

Federal Register (February 16, 2012).[3] To date, there have been no successful legal challenges to these new rules. EPA subsequently revised provisions regarding emission rates during shut-down and start-up periods and reporting requirements. The baseline of this analysis assumes the implementation of MATS in 2015.

The Regional Haze program came out of a provision of the Clean Air Act of 1977 to restore visibility to Class 1 federal areas. The EPA passed the Regional Haze Rule in 1999 which required states to develop SIPs to reduce visibility-impairing pollution. In March 2012 a consent decree was finalized between EPA and a number of parties to develop Regional Haze State Implementation Plans ("SIPs"). The consent decree is driving retrofits of SCRs and retirements, particularly in the western U.S., but it is does not require specific controls for specific sources. A number of announced and proposed retirements are part of utility plans to comply with regional haze including Public Service of New Mexico (San Juan 2 and 3), Public Service of Oklahoma (one unit at Northeastern plant), Arizona Electric Power (one unit at Apache), Salt River Project (one unit at Navajo), and Arizona Public Service (one unit at Cholla). The retirements believed to be necessary to comply with regional haze requirements are included in the baseline. In the eastern U.S., EPA had agreed that CSAPR would meet the requirements of the Regional Haze rule. After CSAPR was vacated by the D.C. Circuit, it was unclear exactly what would occur and a number of eastern states mounted challenges to the regional haze rule itself. With the reinstatement of CSAPR, regional haze programs for eastern states remain in abeyance. The baseline assumes that compliance with MATS will be sufficient.

EPA proposed a new source performance standard (NSPS) for carbon dioxide (CO_2) for new base load fossil-fuel generating units (not combustion turbines) under Section 111(b) of the Clean Air Act in April 2012. This proposal stems from EPA's 2009 finding that emissions of greenhouse gases ("GHGs") endanger both the public health and welfare. The proposal calls for applicable facilities to be subject to an output-based standard of 1,000 pounds of CO_2 per megawatt-hour. EPA established the standard based upon uncontrolled emissions from natural gas combined-cycle plant. According to EPA, new solid fuel fired plants could meet the standard either by employing carbon capture and storage (CCS) at start-up or through a 30-year averaging option. EPA stated in its proposal that this NSPS obligation would not be triggered if the installation of pollution controls or for new plants which commence construction within 12 months of the proposal. This rule was not finalized. Rather on September 20, 2013 EPA released the draft new Proposed Carbon Pollution Standard for new Power Plants, replacing the 2012 standard. For new coal plants, EPA determined that CCS technology has been adequately demonstrated, and its implementation costs reasonable. Therefore, the EPA based the standards for coal plants units on partial CCS technology achieving an emission level of 1,100 lb CO_2/MWh[4]. While the rule has not been finalized, a capital hurdle is included in the baseline for new coal plants not equipped with CCS in

[3] Basically three years with an ability to obtain a one-year extension.

[4] https://www.federalregister.gov/articles/2014/01/08/2013-28668/standards-of-performance-for-greenhouse-gas-emissions-from-new-stationary-sources-electric-utility#h-39

order to reflect the difficulty associated with permitting and delays.[5] Under the current baseline methodology, new coal plants are not competitive with other base load options resulting in no new announced coal plants being constructed.

On June 15, 2012, the EPA proposed a rule that would increase the stringency of the primary annual National Ambient Air Quality Standard ("NAAQS") for fine particulate matter ("$PM_{2.5}$") before the end of the year. The proposal retains the 24-hour primary standard for $PM_{2.5}$ but establishes a new secondary $PM_{2.5}$ NAAQS to address visibility impacts. EPA did not revise the NAAQS for coarse particulate matter ("PM_{10}"). On December 14, 2012, the EPA finalized the NAAQS for fine particulates. EPA grandfathered pre-construction permitting applications under certain situations. EPA indicated it anticipates making initial attainment/nonattainment designations by December 2014 with those designations becoming effective in 2015. States will have five years after designations are effective to meet the revised NAAQS. States can request extensions for additional five years. No additional controls are assumed to be required to comply with the fine particulate NAAQS.

In June 2010, EPA published its proposed rule to address the disposal of coal ash and other combustion waste which includes two options for disposal, both of which fall under the Resource Conservation and Recovery Act ("RCRA"). Under the first proposal, EPA would list these residuals as special wastes subject to regulation under subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under the second proposal, EPA would regulate coal ash under subtitle D of RCRA, the section for non-hazardous wastes. The Agency considers each proposal to have its advantages and disadvantages, and includes benefits which should be considered in the public comment period. Public hearings were held in the summer of 2010; technical corrections were published in August 2010, and the public comment period was extended into November 2010. The final rule has not yet been published The analysis assumes that coal plants will convert wet ash handling systems to dry systems by 2018.

Many power plants use once-through cooling. As such, they withdraw large volumes of water from bodies of water (i.e., rivers, lakes, or the ocean); pump the water through the condenser; and return the water to the same or nearby body of water. The water is generally returned at a temperature much higher than the standing temperature of the water. Water discharges are governed by the Clean Water Act ("CWA"), which is administered by the EPA. CWA Sections 316(a) and (b) address matters important to once through-cooling. CWA Section 316(a) of the CWA provides authority for the states or EPA to issue variances to complying with thermal limits if the discharger demonstrates that alternative thermal limits will not cause significant harm to the aquatic life in the receiving waters. Section 316(b) mandates that the "location, design, construction, and capacity of cooling water intake structures reflect best technology available for minimizing environmental impact." In April 2011, EPA published proposed standards for cooling water intake structures at all existing power generating facilities and existing manufacturing and industrial facilities as part of implementing section 316(b) of the Clean Water Act

[5] EIA uses a similar capital hurdle in its forecasting to reflect permitting challenges and construction-related delays.

(CWA). In May 2014, EPA finalized the rule but not published until August 15, 2014. The rule requires large existing plants which draw 25 percent or more of their cooling water from adjacent bodies to use best available control technology to reduce impingement[6], facilities which withdraw large amounts of water will be required to work with permitting authorities to determine which controls should be used to reduce entrainment[7] mortality, and new units which will be required to limit intake flow to a level similar to a closed cycle recirculation. The analysis assumes compliance with the new rules by 2018.

In April 2013, EPA proposed a rule updating national wastewater discharge standards. Covered under the rule are flue gas desulfurization wastewater; fly ash transport water; bottom ash transport water; combustion residual leachate from landfills and surface impoundments; nonchemical metal cleaning wastes; and wastewater from flue gas mercury control systems and gasification systems.[8] The changes would cover new and existing plants. According to the Federal Register notice, "EPA is considering several options in this rulemaking and has identified four preferred alternatives for regulation of discharges from existing sources." The four preferred options vary with respect to the size of the units covered, whether zero discharge is required from fly ash transport water and wastewater from flue gas mercury controls. EPA is considering as part of this rulemaking the establishment of best management practices ("BMP") requirements that would apply to surface impoundments containing coal combustion residuals (e.g., ash ponds, FGD ponds). Under a consent decree entered into in *Defenders of Wildlife v. EPA*, No. 10-cv-01915 (D.D.C.), and since revised, EPA agreed to publish a final rule by May 22, 2014. A final rule has not yet been filed. No additional requirements related to wastewater discharge are included in the baseline.

In June 2014, the EPA proposed the Clean Power Plan under Section 111(b) of the Clean Air Act, the intent of which is to reduce emissions of carbon dioxide (CO_2) from existing power plants. Under its proposal, the EPA has developed state-specific emission reductions requirements from 2012 emission levels that collectively would achieve a 30 percent reduction in CO_2 emissions from 2005 levels. The EPA developed the targets using a Best System of Emission Reduction (BSER) which consists of four components (building blocks) which EPA used to determine the CO_2 reduction potential for each state. EPA is not requiring the reductions be accomplished in that manner. Each state has flexibility regarding implementation provided its plans are contained in an approved State Implementation Plan (SIP). States are also allowed to form alliances for the purposes of compliance. States are required to submit their SIPs with or without alliance partners for review within one or two years of the final rule being

[6] Impingement is when organisms are trapped on the outer part of an intake structure or against a screening device during period of intake water withdrawal. Impingement can result in physical damage to the organisms.

[7] Entrainment is when organisms are drawn into the intake water flow entering and passing through a cooling water intake structure and into a cooling water system. Entrained organisms are subject to mechanical, thermal, and/or toxic stress.

[8] https://www.federalregister.gov/articles/2013/07/12/2013-16774/effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating-point-source

published. EPA has one year to review. Under the proposal, phased compliance would start in 2020. Comments on the Clean Power Plan were due October 16, 2014 but the period has been extended to December 1, 2014. Legal challenges have commenced, starting with the initial question as to whether Section 111(b) can be the basis for these regulations. This regulation is not assumed in the baseline although the Clean Power Plan[9] is the basis for the Low Coal Demand sensitivity cases.

Electric Generating Capacity

Demand for coal is a function of electricity demand, available generating capacity, and the dispatch of available capable. As shown in Exhibit 6, significant coal-fired power plant closures are expected as a result of several existing and new regulations put forth by the EPA, which require significant new investments in coal-fired power plants in order to allow them to operate. The forecast incorporates 1.5 GW of new coal-fired capacity, all of which is project specific. No additional coal plants beyond the 1.5 GW are included through the forecast period.[10] Modest additions are expected to nuclear capacity including both up-rates and new plants. The largest increase is in combined-cycle natural gas capacity.

Exhibit 6. Generation Capacity Changes (Megawatts, MW)

	2013-2015	2016-2020	2021-2025	2026-2030	2031-2035	2036-2040
Coal Capacity Additions	1,529	-	-	-	-	-
Coal Capacity Retirements	21,865	27,104	4,477	7,971	20,212	33,887
Nuclear Capacity Additions	1,180	5,019	-	-	-	-
Combine-Cycle Natural Gas Capacity	15,964	47,638	8,573	40,061	96,203	105,932

Other Domestic Markets

Although much smaller than the utility market, the domestic metallurgical and industrial/other coal markets are significant sources of U.S. coal demand. Domestic metallurgical coal demand is tied to coke oven capacity which is expected to decline over the forecast period as retirements of existing ovens exceed additions of new ones. The industrial/other market is expected to decline due to fuel switching and lost demand. The industrial/other and domestic metallurgical coal forecasts, shown in Exhibit 7, were fixed for the analysis.

[9] The Clean Power Plan analyzed in the low case assumes individual state compliance with mass-based limits rather than cap-based limits. While EPA has indicated mass-based compliance is an option, the exact conversions from a cap-based rate to a mass-based rate has not yet been finalized.

[10] Additional coal plants are possible depending upon permitting and advances in carbon capture and sequestration.

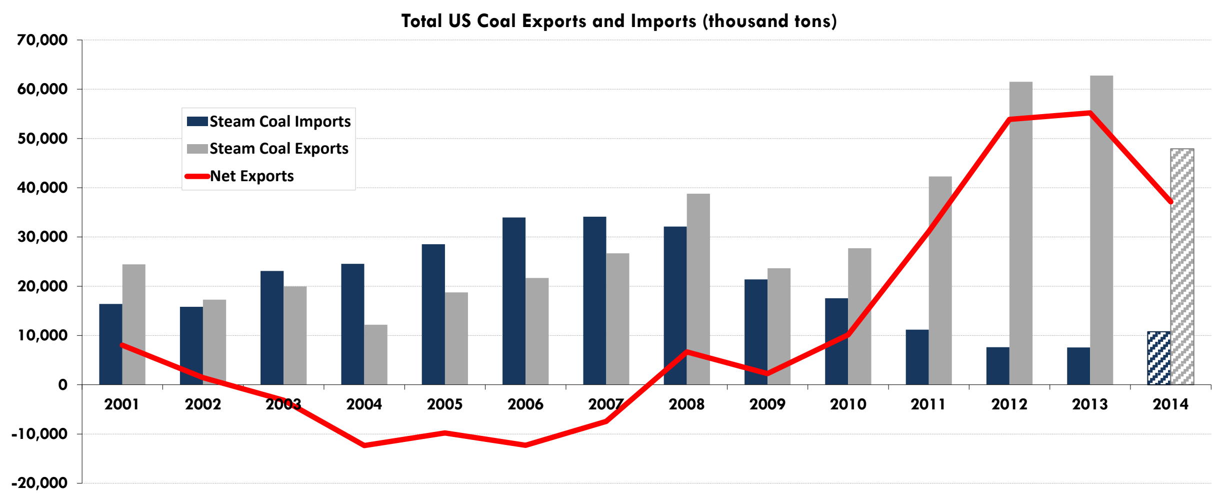
Exhibit 7. Non-Utility U.S. Coal Demand (Million Tons)

	Actual	Forecast					
	2013	2015	2020	2025	2030	2035	2040
Domestic Metallurgical	21.6	21.4	20.6	20.5	20.3	20.2	20.1
Industrial/Other	47.0	42.7	39.7	38.1	36.7	35.7	34.8
TOTAL Non-Utility	68.6	64.1	60.3	58.6	57.0	55.9	54.9

Exports

The recent growth in U.S. coal has restored the U.S. to export levels not experienced since the early 1990's (Exhibit 8).

Exhibit 8



2014 is annualized from YTD data

U.S. coal exports include metallurgical ("met") coal and steam coal. The met coal, which is primarily used to produce metallurgical coke for steel-making, consists of a variety of grades typically differentiated by volatility and reflectance. Almost all met coal exports originate in the Appalachian region. Steam coal exports are of different types and origins, including low-sulfur and high-sulfur Appalachian coals, high-sulfur Illinois Basin coal, Rockies bituminous coals, and Powder River Basin sub-bituminous coal. Imports of coal to the U.S. are almost entirely steam coal delivered to power plants on the Gulf Coast and East Coast. Imported steam coals principally originate from South America (Colombia and Venezuela) and displace coal produced in Appalachia.

U.S. met coal exports increased in response to strong world met coal market prices in 2008 and then again starting in 2011. From the historical low point of 22 million tons per year in 2002 and 2003, met coal exports exceeded 60 million tons in 2012 and 2013. This coal is shipped to world markets primarily out of the East Coast ports of Hampton Roads and Baltimore, the Gulf Coast ports of Mobile and New Orleans and the Great Lakes ports to Canada.

The traditional source of U.S. steam coal exports was bituminous coal from Appalachia (principally low-sulfur coal), which was best suited to the quality specifications of the world market. This coal was shipped out of the East Coast and Gulf Coast ports to world markets. When world market prices were low prior to 2008, U.S. steam coal exports fell to very low levels and steam coal imports were rising steadily. The change in world coal markets since 2007 caused a sharp drop in steam coal imports and an increase in steam coal exports.

World coal prices increased dramatically in 2007/2008 and then again in 2011due to a number of factors. The most significant reasons have been:

- A significant decline in the value of the US dollar, especially when compared with the currency of other coal exporting countries. As world coal trade is U.S. dollar-denominated and the U.S. is a relatively minor player, the lower value for the U.S. dollar causes world prices to rise as the other coal exporters seek to maintain net revenues. A weak dollar makes U.S. exports more competitive in world markets and imports to the U.S. more expensive. The dollar as measured against the Australian dollar (the world's largest coal exporter, especially of met coal) has been falling since 2002 (except for a brief period in the second half of 2009) and has had a major impact on world coal prices and US coal exports. Large coal demand growth in Asia, especially China and India. The increased demand for imports from world coal markets, both for met coal and steam coal has driven the growth of US coal exports.

Since 2013, there has been a decline in world coal prices as a result of the U.S. dollar regaining some of its prior strength versus the Australian dollar. In addition, the high metallurgical coal prices in 2011 resulted in significant mine and infrastructure development in Australia significantly increasing global supply.

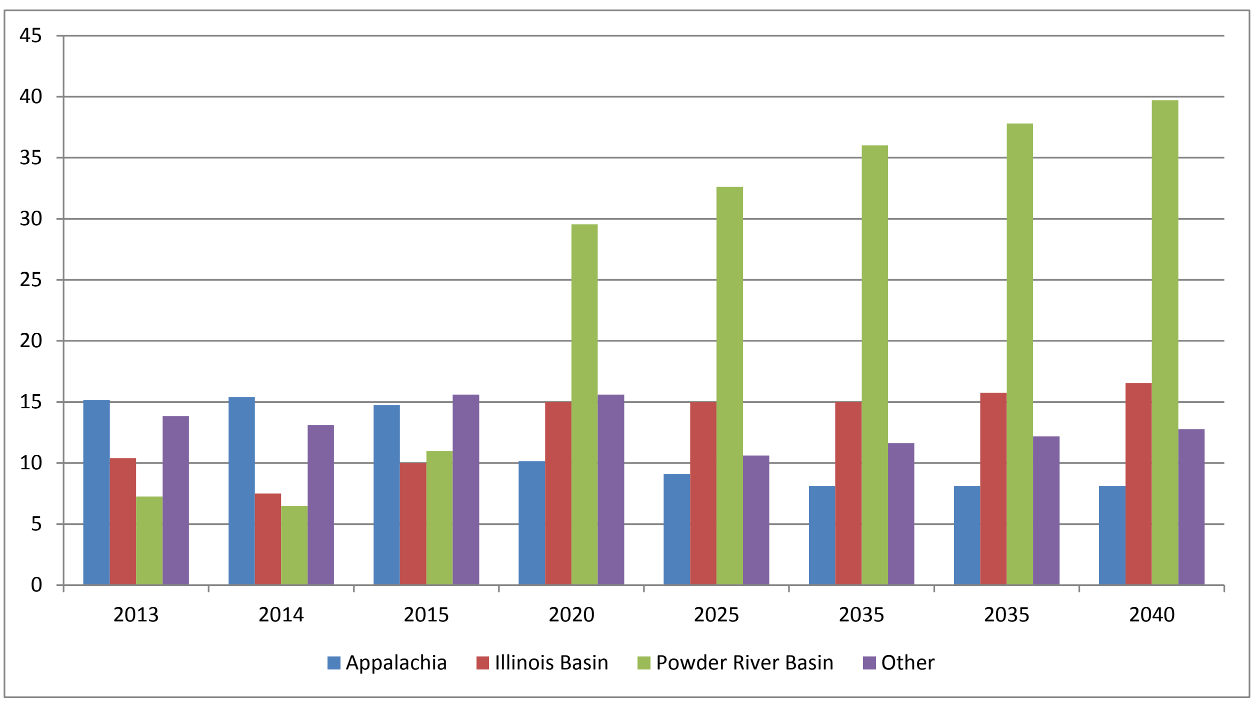
While in the past, U.S. coal exports were generally limited to Appalachian coal, the increase in world prices and demand have made coals from the Illinois Basin and Powder River Basin attractive to export to the steam market. These coals had previously not participated due to quality limitations of sulfur (Illinois Basin) and heat content (Powder River Basin). However, the increase in price of other coals has made the coals low-cost on a quality-adjusted basis, so there is now an economic incentive to use these coals instead of the traditional low-sulfur bituminous coals.

The base forecast, which is based upon an assumption of parity between the U.S. and Australian dollars, assumes U.S. coal exports remain strong through the forecast period. As shown in Exhibit 9, exports are expected to stay above 100 million tons per year throughout. However, the mix of exports is expected to change from primarily metallurgical to primarily steam. The shift reflects the limited remaining U.S. metallurgical coal supply combined with increased production from both Australia and Canada and non-traditional sources such as Mozambique and Mongolia.

Exhibit 9. Forecast of U.S. Coal Exports (Million Tons)

In addition, the mix of steam coal exports is expected to change over the forecast period. As shown in Exhibit 10, the largest growth in exports is expected to come from the Illinois Basin and the Powder River Basin. Exports from Appalachia are expected to decline from current levels due to their relatively high production costs and the market acceptance of the other coal types.

Exhibit 10. U.S. Steam Coal Exports (Million Tons)



There is sufficient terminal capacity (existing or under firm development) on the east coast of the U.S. and the U.S. Gulf. In order to realize the export forecast for western U.S. coals, one or more domestic terminals must be constructed on the west coast. Currently western coals are primarily being exported through Canadian terminals in British Columbia, the St. Lawrence Seaway, and the U.S. Gulf.[11] In order to be competitive in the Pacific market in the long-term, exports of Powder River Basin coal cannot afford the extra freight these options entail.

Coal Pricing

Coal is not a national commodity. Production from the five major coal producing regions moves to wide-spread markets. Production from the other coal producing regions is largely consumed locally. The U.S. coal market is a set of overlapping regional markets with loose connections reflecting the variability in coal quality between regions and the significance of transportation costs. Customers can and do switch between supply regions but such switching generally requires capital expenditures for plant modifications and changes to delivery process and can take time depending on the modifications required. Over the last 10 plus years, the shift in coal production from eastern coal supply sources to western coal supply sources due to the continued penetration of Powder River Basin coals into eastern coal markets has increased the price linkage between Powder River Basin coals and eastern coals. The retrofitting of pollution control technology will further link coal price as the fungibility in coal supply increases.

Long-term coal prices are set by the full cost of production (including cash operating costs and return of and on capital investment) of the price setting mines within a producing region. Prices can vary around the long-term “equilibrium” price based on market conditions. In the short term, the floor on coal prices is the cash operating cost for the marginal producer, which forces a decline in production. The short-term ceiling on coal prices is the price at which demand declines, generally through customers switching to a different coal, but possibly switching to a different fuel (pet coke) or a different generation source (natural gas combined cycle priced on the grid). Because it takes time for the market to respond to coal price changes (including capital), disequilibrium pricing can last for an extended period (two to three years) before markets correct.

Global steam coal prices are typically set in key market hubs with the market participants realizing netback pricing at their respective loadports. For example, the key market hub for the Atlantic market is Amsterdam, Rotterdam, and Antwerp (ARA). Prices from the Hampton Roads area would be the quality-adjusted ARA price less freight from Hampton Roads; prices from Puerto Bolivar would be the quality-adjusted ARA price less freight from Colombia. Global metallurgical coal prices are typically tied to the benchmark prices established between the Japanese Steel Mills (the single largest customer for metallurgical coal) and the Australian producers (the single largest source of supply). This price typically sets the market price for most of the world’s coking coal market with other suppliers and customers settling at similar amounts on a quality- and transportation-adjusted basis.

[11] There are also some most exports through west coast U.S. terminals.

Description of EVA Methodology

The methodology EVA developed to evaluate the impact of the SPR alternatives on coal demand and coal costs consisted of the following steps:

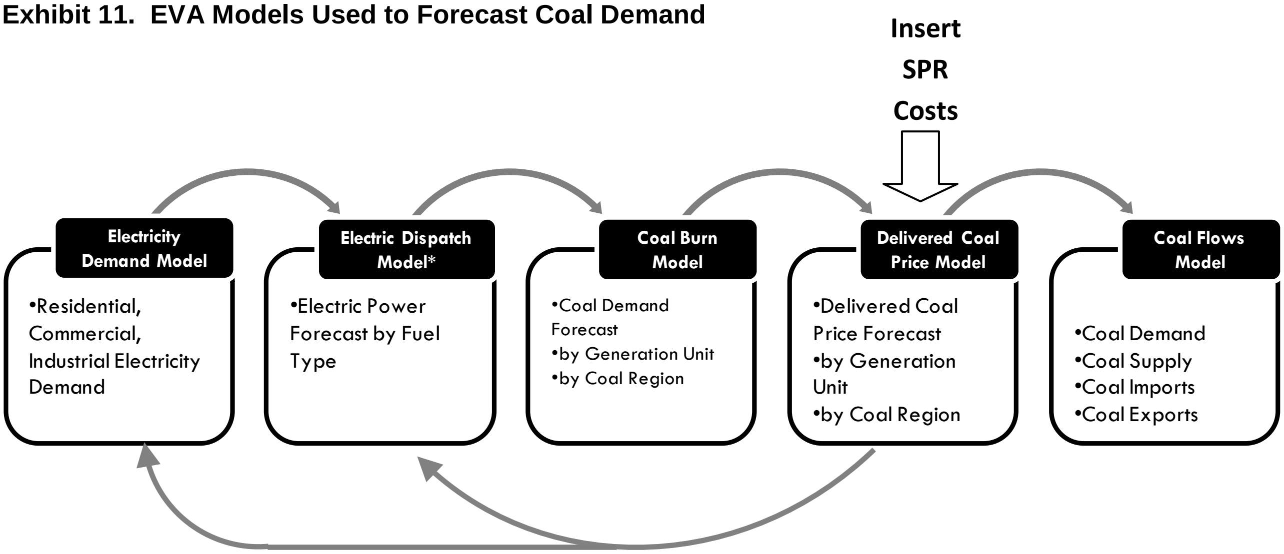
- Develop baseline forecast for SPR analysis
- Develop price forecasts consistent with cost increases for each of the Alternatives.
- Evaluate the impact of the prices under the alternatives on utility coal demand
- Compare coal demand under the alternatives to baseline demand
- Develop high and low coal demand baseline forecasts for SPR analysis
- Evaluate the impact of the selected regulatory option with the high and low baseline forecasts

EVA Baseline Forecast and Analysis Methodology

Using EVA's market assumptions discussed earlier that relate to electric power demand, environmental regulations, capacity retirements and additions, non-utility domestic coal consumption, exports, and coal pricing methodology, EVA developed a baseline demand forecast from which to compare each SPR alternative.

In order to analyze the impacts of each SPR alternative on electric power demand and the coal industry, EVA employs multiple inter-related models, shown in Exhibit 18. The key models affecting coal demand are shown in Exhibit 11, to formulate its analysis. The following sections provide a summary of each model utilized.

Exhibit 11. EVA Models Used to Forecast Coal Demand



Electricity Demand Model

The electricity demand model forecasts monthly demand for the residential, commercial, industrial and transportation sectors for each U.S. power market. To forecast long-term electricity demand, EVA performs regression techniques against EIA's 826-data, which consists of monthly electric utility sales and revenue, along with the following variables:

Variable	Source
Number of Households	Moody's Analytics, U.S. Macro/Financial Forecast Database, 2011
Disposable Income and GDP	
Industrial Production Index	
Heating/Cooling Degree Days	Historical data from National Oceanic and Atmospheric Administration used to develop forecast[12]
Energy Efficiency Measures	EPRI's Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (January 2009)
Delivered Fuel Prices	Historical delivered coal prices adjusted by market intelligence and future forecasts of coal and transportation costs
Retail Power Prices	Historical retail and average wholesale on- and off-peak power prices by major electricity trading hub from EIA adjusted for changes in market prices and utility rate base.
Price Elasticity of Demand	Price elasticity factors by market developed by EIA.[13]
Electric Car Penetration	EVA's independent forecast of electric car sales and related consumption

Electric Dispatch Model

EVA utilizes the AuroraXMP dispatch model containing EVA's market data to determine future long-term coal generation demand. The model analyzes the entire U.S. electric power market on an 8760 hourly basis, which intends to mirror real world power pool dispatch operations. EVA's inputs into Aurora include the following:

Element	Source/Description
Power Plant Capacity Additions	EVA tracks new power plant announcements, permitting, financing and construction; unit retirements; and major environmental control retrofit projects. This information is incorporated according to EVA judgment.
Projected Plant Retirements	In addition to announced retirements, EVA analyzes what and when additional units will be retired as a result of new and expected EPA rules.
Construction and Performance Costs	EVA uses its internal forecast of new capacity costs and performance for alternative electricity supply options.
Renewable Portfolio Standards	State RPS requirements are incorporated into the model.
Fuel Costs	Delivered coal costs are developed for each coal-fired generator based upon forecasts of coal prices and transportation rates.

[12] NOAA, National Weather Service Climate Prediction Center, Degree Day Statistics, http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/, last updated November 18, 2009.

[13] Annual Energy Outlook

Coal Burn Model

EVA's coal burn model summarizes the quantity (tons) of coal that each coal-fired plant will consume by supply region. This is performed by analyzing each plant's forecasted coal generation determined from the electric supply model, its respective heat rate and future coal purchase decisions. The sources of the major inputs to the Coal Burn Model are:

Input	Source/Description
Forecasted Coal Generation by Power Plant	Electric Dispatch Model
Coal Receipts	EIA-923 data to summarize the current quality and quantity of coal purchased for each power plant.
Coal Selections	EVA determined plant-specific fuel strategy by year for the forecast period.
Heat Rate	Net heat rate for each plant using EIA-923 data except as deemed appropriate to modify

Delivered Coal Price Model

EVA maintains an engineering-based cost model that organizes the cost components (labor, fuel, supplies, etc.) to produce coal along with profit margins for each coal supply region. The long-term coal price forecast assumes market equilibrium and therefore reflects full operating costs of the price setting mines in each region with a return of and on capital. The produced coal cost is commonly termed 'Mine Price'. Prices for other qualities within each region are derived from the price-setting mines.

In order to calculate the delivered price of coal for each coal-fired plant, EVA estimates the transportation cost to ship coal from the mine to each utility using a combination of known transportation costs, typical rail and barge rate metrics (cents per ton-mile), and other relevant information. The combination of the mine price and the transportation cost produce the delivered price of coal.

The results from the coal burn model and the delivered coal price model are combined to calculate the average cost of coal for each coal-fired plant.

Coal Flows Model

EVA's Coal Flows Model combines the forecasts of utility coal demand (by supply region) with EVA's independent analysis of export, industrial/commercial, and domestic metallurgical coal demand to produce coal flows by region. The results of the coal flows model are evaluated in the context of regional production capacity. If the demand forecast exceeds the regional forecast production capacity, adjustments are made to the Coal Price Model and/or the independent non-utility coal demand assessments to balance the market. As a result, the Coal Flows may be run multiple times until the markets are balanced.

SPR Impacts on Coal Prices

SPR compliance costs were, on a per ton basis, translated into a price impact based upon the significance of the affected production. Under all three alternatives, the most significant cost impact was on "large" Central Appalachia surface mines.

As shown in Exhibit 12, of the 127.7 million tons of Central Appalachia production in 2013, 57.7 million tons came from surface mines and 21.5 million tons came from surface mines that produced 1.0 million tons or more in 2013. In 2013, large surface mines accounted for 37 percent of surface mine production or 17 percent of total production. Given this relatively large share of production and the price formation methodology, EVA determined that the full cost of large surface mine compliance plus the associated royalty adjustment would flow through the Central Appalachia price.

Exhibit 12. Production from Large Central Appalachia Surface Mines in 2013 (1,000 Tons)

State	Company	Mine Coplex	Operator	Mine	MSHA ID	Tons
WV	Arch Coal	Coal-Mac	PHOENIX COAL MAC MINING INC	HOLDEN #22	4608984	2,830
WV	Alpha	Elk Run	PROGRESS COAL	TWILIGHT MTR SURFACE MINE	4608645	2,502
WV	Patriot Coal	Corridor G	HOBET MINING, INC.	Hobet 21	4604670	2,335
WV	Alpha	Republic	ELK RUN COAL COMPANY INC	REPUBLIC ENERGY	4609054	2,111
WV	Patriot Coal	Guyan	APOGEE COAL COMPANY	Guyan	4608939	1,812
WV	Alpha	Homer III	ELK RUN COAL COMPANY INC	BLACK CASTLE SURFACE MINE	4607938	1,771
KY	Blackhawk Mining	Hoyt	PINE BRANCH COAL SALES INC	COMBS BRANCH	1516883	1,373
WV	Patriot Coal	Paint Creek	CATENARY COAL COMPANY	Samples Mine	4607178	1,298
WV	Mechel	Coal Mountain	DYNAMIC ENERGY	COAL MOUNTAIN NO. 1	4609062	1,186
KY	Arch Coal	Hazard	ICG HAZARD	EAST MAC & NELLIE	1518966	1,148
WV	Consol Energy	Millers Creek	Consol of Kentucky	MT-101	4609075	1,108
WV	Alpha	Goals	ALEX ENERGY INC	EDWIGHT SURFACE MINE	4608977	1,018
WV	Eagle Hawk Carbon	Fork Creek	COAL RIVER MINING LLC	Mine No. 6	4609286	1,010
	TOTAL					**127,714**
	Surface					**57,718**
	Underground					**69,996**
	Surface > 1MMTYP					**21,503**
	Percent of Surface> 1 MMTPY of Surface					**37%**
	Percent of Surface> 1 MMTPY of Total CAPP					**17%**

Source: MSHA, EVA

As an example, the highest cost impact[14] of Alternative 2 on Central Appalachia production costs is $2.20 per ton. For the reasons described above, the price increase for Central Appalachia under Alternative 2 is approximately $3.18 per ton[15].

A different approach was taken to determine the impact of costs in other supply regions based upon the cost impact and the make-up of the supply region. In some cases, the entire cost applied to the price for that region. In other cases, the cost impacts were weighted by the mix of production. In Northern Appalachia for example, surface mine production accounts for a small share of total production and,

[14] All impacts are in real 2014 $/ton

[15] The $2.20 per ton plus an assumed royalty.

more importantly for the purposes of this analysis, the surface mines in Northern Appalachia are not the price setting mines. As a result, if the entire cost impact was assumed to apply to all Northern Appalachia production, it would overstate the impact.

The prices for the key price-setting mines in each of the major coal supply regions under the baseline and the SPR alternatives are provided in Exhibit 15 in real 2014 dollars.

Exhibit 15. Forecast Coal Prices ($/Ton)

Alternative	Coal Region	Category	BTU/lb	SO2*	Ash (%)	Real 2014$ 2015	2020	2030	2040
Base	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.26	$ 63.03	$ 69.98
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 67.34	$ 70.43	$ 74.27
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 44.75	$ 46.15	$ 47.72
	PRB	High Btu	8,800	0.8	5.0	$ 14.19	$ 16.02	$ 17.33	$ 19.57
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.50	$ 38.95	$ 39.60
ALT2	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.42	$ 63.19	$ 70.14
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 70.52	$ 73.60	$ 77.44
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 45.15	$ 46.57	$ 48.13
	PRB	High Btu	8,800	0.8	5.0	$ 14.17	$ 16.06	$ 17.38	$ 19.62
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.61	$ 39.05	$ 39.70
ALT3	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.41	$ 63.18	$ 70.12
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 69.02	$ 72.11	$ 75.94
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 45.00	$ 46.41	$ 47.97
	PRB	High Btu	8,800	0.8	5.0	$ 14.17	$ 16.06	$ 17.37	$ 19.62
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.60	$ 39.05	$ 39.70
ALT4	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.46	$ 63.23	$ 70.18
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 68.55	$ 71.63	$ 75.47
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 45.00	$ 46.42	$ 47.98
	PRB	High Btu	8,800	0.8	5.0	$ 14.17	$ 16.07	$ 17.38	$ 19.62
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.62	$ 39.07	$ 39.72
ALT5	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.41	$ 63.18	$ 70.12
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 68.22	$ 71.31	$ 75.14
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 44.75	$ 46.15	$ 47.72
	PRB	High Btu	8,800	0.8	5.0	$ 14.17	$ 16.00	$ 17.32	$ 19.56
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.50	$ 38.95	$ 39.60
ALT6	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.28	$ 63.05	$ 70.00
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 67.66	$ 70.74	$ 74.58
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 44.96	$ 46.37	$ 47.94
	PRB	High Btu	8,800	0.8	5.0	$ 14.17	$ 16.01	$ 17.32	$ 19.56
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.52	$ 38.97	$ 39.62
ALT7	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.47	$ 63.24	$ 70.19
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 68.56	$ 71.65	$ 75.48
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 45.12	$ 46.54	$ 48.11
	PRB	High Btu	8,800	0.8	5.0	$ 14.17	$ 16.05	$ 17.36	$ 19.61
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.61	$ 39.05	$ 39.70
ALT8	NAPP	Pittsburgh :	13,000	4.0	8.0	$ 56.04	$ 58.39	$ 63.16	$ 70.11
	CAPP	Low Sulfur	12,500	1.6	10.0	$ 64.00	$ 68.20	$ 71.28	$ 75.12
	ILB	Illinois	11,500	5.0	10.0	$ 42.48	$ 44.99	$ 46.40	$ 47.97
	PRB	High Btu	8,800	0.8	5.0	$ 14.19	$ 16.07	$ 17.38	$ 19.62
	RCK	Utah	11,800	1.0	10	$ 36.24	$ 38.60	$ 39.05	$ 39.69

Evaluation of the Impact of SPR Alternatives on Coal Demand

The prices under the alternatives were run through the suite of EVA models. The revised electricity demand and revised coal generation produced different a level and mix of utility coal demand for each alternative. The resulting utility coal demand numbers were aggregated with the non-utility and domestic demand numbers to produce total demand for U.S. coal that could be compared across scenarios.

The standard outputs from EVA models are coal demand by supply region. OSM categorizes its mining regions differently. EVA re-categorized its results to match the OSM regions as shown in Exhibit 16.

Exhibit 16. OSM and EVA Regions

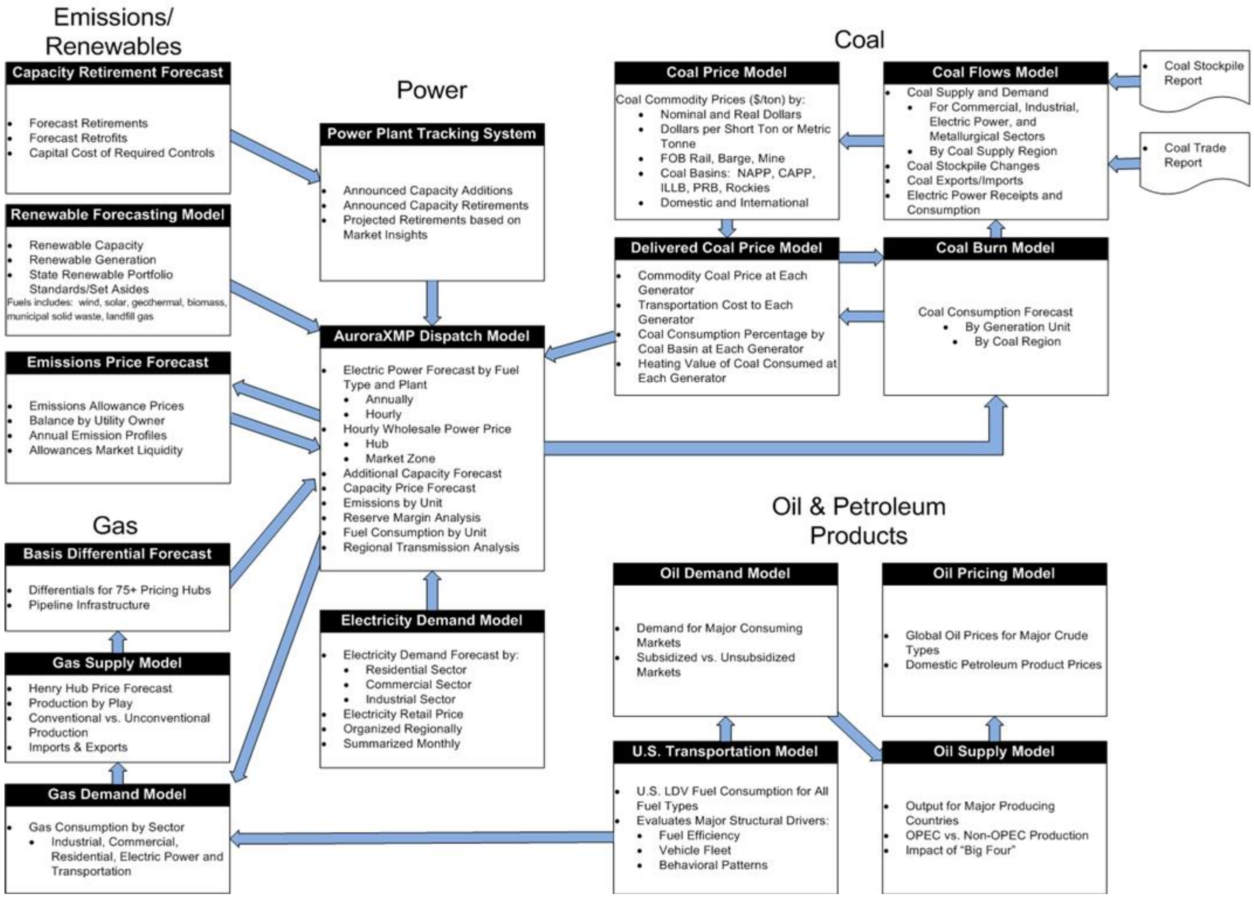
OSM Regions	EVA Regions
Appalachian Basin	Northern Appalachia Central Appalachia Alabama
Colorado Plateau	Rockies except SWY and MT Southwest
Gulf Coast	Lignite except ND and MT
Illinois Basin	Illinois Basin
North Rocky Mountains/Great Plains	Rockies (SWY, MT) Lignite (ND, MT) Powder River Basin
Northwest	Washington Alaska
Interior	Interior

In order to assist IEc in performing its analysis, EVA also re-categorized its results to estimate production at the state level and by mine type. (Exhibit 17) These dis-aggregations were based upon a combination of the historical production mix and planned production.

Exhibit 17. EVA Regions and States

EVA Regions	States
Northern Appalachia Central Appalachia Alabama	Maryland, Pennsylvania, Ohio, West Virginia Kentucky, Tennessee, Virginia, West Virginia Alabama
Rockies except SWY and MT Southwest	Colorado, New Mexico. Utah Arizona, New Mexica
Lignite except ND and MT	Louisiana, Mississippi, Texas
Illinois Basin	Kentucky, Illinois, Indiana
Rockies (SWY, MT) Lignite (ND, MT) Powder River Basin	Wyoming, Montana Montana, North Dakota Montana, Wyoming
Washington Alaska	Washington Alaska
Interior	Arkansas, Missouri, Oklahoma

Exhibit 18. EVA MODELING MODULES



APPENDIX G: 3 PERCENT

ALTERNATIVE 8

Exhibits G-1 through G-3 show compliance costs and welfare effects under Alternative 8, discounted at 3 percent. The tables with 7 percent discounting and a discussion of the methodology behind each calculation can be found in Chapter 4 for compliance costs and Chapter 5 for welfare effects.

EXHIBIT G-1. SUMMARY OF TOTAL INDUSTRY AND GOVERNMENT COMPLIANCE COSTS OF THE PROPOSED RULE, ANNUALIZED, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$19,000,000	$1,600,000	$3,300	$21,000,000
	UG	$2,000,000	$3,800,000	$5,500	$5,800,000
Colorado Plateau	Surface	$3,000,000	$53,000	$1,600	$3,100,000
	UG	$140,000	$88,000	$1,100	$230,000
Gulf Coast	Surface	$7,000,000	$140,000	$3,100	$7,000,000
Illinois Basin	Surface	$16,000,000	$270,000	$1,800	$16,000,000
	UG	$0	$320,000	$6,000	$320,000
Northern Rocky Mountains and Great Plains	Surface	$5,600,000	$82,000	$29,000	$5,800,000
Northwest	Surface	$100,000	$14,000	$120	$120,000
Western Interior	Surface	$660,000	$11,000	$73	$670,000
	UG	$0	$630	$6	$640
Total U.S. Compliance Cost Impacts	Surface	$52,000,000	$2,200,000	$39,000	$54,000,000
	UG	$2,100,000	$4,200,000	$13,000	$6,400,000
	TOTAL	**$54,000,000**	**$6,400,000**	**$52,000**	**$60,000,000**
Note: Totals may not sum due to rounding.					

EXHIBIT G-2. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 8, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$38.9	$0.05	$39.0
2021	$32.2	$0.05	$32.3
2022	$17.9	$0.05	$18.0
2023	$26.0	$0.05	$26.1
2024	$41.3	$0.05	$41.4
2025	$31.5	$0.05	$31.5
2026	$33.3	$0.05	$33.3
2027	$30.7	$0.04	$30.7
2028	$28.1	$0.04	$28.2
2029	$33.2	$0.04	$33.2
2030	$34.4	$0.04	$34.4
2031	$33.7	$0.04	$33.7
2032	$34.9	$0.04	$34.9
2033	$32.2	$0.04	$32.3
2034	$29.5	$0.03	$29.6
2035	$31.7	$0.03	$31.7
2036	$29.8	$0.03	$29.8
2037	$30.7	$0.03	$30.8
2038	$31.4	$0.03	$31.4
2039	$29.0	$0.03	$29.1
2040	$27.1	$0.03	$27.2
Annualized Value Over the 2020-2040 Period	**$42.7**	**$0.1**	**$42.7**

EXHIBIT G-3. ESTIMATED COAL SEVERANCE TAX REVENUE CHANGES OF THE PROPOSED RULE, 2020-2040, THREE PERCENT DISCOUNT RATE

REGION	NET PRESENT VALUE	ANNUALIZED
Appalachian Basin		
Alabama	($121,000)	($7,860)
Kentucky[1]	($5,110,000)	($331,000)
Ohio	($216,000)	($14,000)
Tennessee	($37,000)	($2,400)
West Virginia	($24,000,000)	($1,560,000)
Regional Total:	($29,500,000)	($1,910,000)
Colorado Plateau		
Colorado	$14,100	$915
New Mexico	$119	$8
Regional Total:	$14,200	$923
Gulf Coast		
Louisiana	$7	$0
Regional Total:	$7	$0
Illinois Basin		
Kentucky[1]	($5,110,000)	($331,000)
Regional Total:	($5,110,000)	($331,000)
Northern Rocky Mountains and Great Plains		
Montana	($1,380,000)	($89,500)
North Dakota	$0	$0
Wyoming	($5,900,000)	($383,000)
Regional Total:	($7,280,000)	($472,000)
Northwest		
Alaska	$0	$0
Regional Total:	$0	$0
Western Interior		
Arkansas	$0	$0
Kansas	$0	$0
Regional Total:	$0	$0
TOTAL	**($41,900,000)**	**($2,720,000)**

Notes: Impacts are calculated as a difference from Alternative 1 projections, which represent existing regulatory requirements.
[1] Production in Kentucky is split evenly across the Appalachian Basin and Illinois Basin regions.

ALTERNATIVES 2-7

Exhibits G-4 through G-17 show compliance costs and welfare effects under Alternatives 2 through 7, discounted at 3 percent. The tables with 7 percent discounting and a discussion of the methodology behind each calculation can be found in Chapter 4 for compliance costs and Chapter 5 for welfare effects.

EXHIBIT G-4. ANNUALIZED COMPLIANCE COSTS UNDER ALTERNATIVES 2-7, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachia	$82,000,000	$45,000,000	$43,000,000	$33,000,000	$13,000,000	$41,000,000
Colorado Plateau	$4,800,000	$4,500,000	$5,400,000	$0	$660,000	$2,900,000
Gulf Coast	$11,000,000	$10,000,000	$11,000,000	$0	$1,000,000	$1,800,000
Illinois Basin	$32,000,000	$20,000,000	$20,000,000	$0	$17,000,000	$3,000,000
Northern Rocky Mountains	$9,600,000	$8,900,000	$9,800,000	$0	$1,000,000	$1,500,000
Northwest	$190,000	$150,000	$160,000	$0	$53,000	$16,000
Western Interior	$1,300,000	$800,000	$810,000	$0	$670,000	$120,000
TOTAL	**$140,000,000**	**$89,000,000**	**$90,000,000**	**$33,000,000**	**$33,000,000**	**$50,000,000**

EXHIBIT G-5. ANNUAL SEVERANCE TAXES UNDER ALTERNATIVES 2-7, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	ALTERNATIVE 2	ALTERNATIVE 3	ALTERNATIVE 4	ALTERNATIVE 5	ALTERNATIVE 6	ALTERNATIVE 7
Appalachian Basin[1]	($4,820,000)	($2,790,000)	($2,270,000)	($1,970,000)	($1,110,000)	($2,410,000)
Colorado Plateau	$143	($710)	$848	$497	$186	$1,340
Gulf Coast	$66	($76)	($161)	$31	$88	$12
Illinois Basin[1]	($873,000)	($450,000)	($380,000)	($282,000)	($217,000)	($430,000)
Northern Rocky Mountains and Great Plains	($464,000)	($483,000)	($474,000)	($478,000)	($456,000)	($471,000)
Northwest	$0	$0	$0	$0	$0	$0
Western Interior	$0	$0	$0	$0	$0	$0
TOTAL	**($6,160,000)**	**($3,720,000)**	**($3,130,000)**	**($2,730,000)**	**($1,780,000)**	**($3,310,000)**

[1] Production in Kentucky is evenly divided between the Appalachian Basin and Illinois Basin regions.

ALTERNATIVE 2

EXHIBIT G-6. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 2, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$73,000,000	$3,000,000	$3,100	$77,000,000
	UG	$2,100,000	$3,800,000	$5,500	$8,900,000
Colorado Plateau	Surface	$4,500,000	$160,000	$1,600	$4,600,000
	UG	$140,000	$88,000	$1,100	$230,000
Gulf Coast	Surface	$11,000,000	$410,000	$3,140	$11,000,000
Illinois Basin	Surface	$31,000,000	$760,000	$1,800	$32,000,000
	UG	$0	$320,000	$6,000	$320,000
Northern Rocky Mountains and Great Plains	Surface	$9,300,000	$240,000	$29,000	$10,000,000
Northwest	Surface	$160,000	$23,000	$120	$190,000
Western Interior	Surface	$1,300,000	$31,000	$73	$1,300,000
	UG	$0	$630	$6	$640
Total U.S. Compliance Cost Impacts	Surface	$130,000,000	$4,700,000	$39,000	$140,000,000
	UG	$2,200,000	$4,200,000	$13,000	$6,400,000
	TOTAL	**$130,000,000**	**$8,900,000**	**$51,000**	**$140,000,000**

Note: Totals may not sum due to rounding.

EXHIBIT G-7. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 2, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$125.3	$0.05	$125.4
2021	$116.0	$0.05	$116.1
2022	$98.5	$0.05	$98.6
2023	$104.2	$0.05	$104.3
2024	$117.7	$0.05	$117.2
2025	$103.9	$0.05	$103.9
2026	$103.1	$0.05	$103.1
2027	$97.5	$0.04	$97.6
2028	$92.2	$0.04	$92.3
2029	$94.3	$0.04	$94.3
2030	$92.5	$0.04	$92.5
2031	$89.0	$0.04	$89.1
2032	$87.8	$0.04	$87.8
2033	$83.0	$0.04	$83.0
2034	$78.0	$0.03	$78.1
2035	$77.5	$0.03	$77.6
2036	$74.1	$0.03	$74.2
2037	$73.1	$0.03	$73.1
2038	$71.8	$0.03	$71.8
2039	$66.6	$0.03	$66.7
2040	$61.9	$0.03	$61.9
Annualized Value Over the 2020-2040 Period	**$1,908**	**$0.84**	**$1,908**

ALTERNATIVE 3

EXHIBIT G-8. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 3, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$36,000,000	$3,300,000	$3,300	$39,000,000
	UG	$2,000,000	$3,800,000	$5,500	$5,800,000
Colorado Plateau	Surface	$4,100,000	$160,000	$1,600	$4,300,000
	UG	$140,000	$88,000	$1,100	$230,000
Gulf Coast	Surface	$9,900,000	$410,000	$3,100	$10,000,000
Illinois Basin	Surface	$19,000,000	$760,000	$1,800	$19,000,000
	UG	$0	$320,000	$5,900	$320,000
Northern Rocky Mountains and Great Plains	Surface	$8,700,000	$240,000	$29,000	$8,900,000
Northwest	Surface	$130,000	$23,000	$120	$150,000
Western Interior	Surface	$770,000	$31,000	$73	$800,000
	UG	$0	$630	$6	$640
Total U.S. Compliance Cost Impacts	Surface	$78,000,000	$4,900,000	$39,000	$83,000,000
	UG	$2,100,000	$4,200,000	$13,000	$6,400,000
	TOTAL	**$80,000,000**	**$9,100,000**	**$52,000**	**$89,000,000**
Note: Totals may not sum due to rounding.					

EXHIBIT G-9. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 3, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$67.7	$0.02	$67.7
2021	$60.5	$0.01	$60.5
2022	$45.2	$0.01	$45.2
2023	$52.7	$0.01	$52.8
2024	$67.3	$0.01	$67.4
2025	$56.5	$0.01	$56.5
2026	$57.7	$0.01	$57.7
2027	$54.2	$0.01	$54.2
2028	$50.9	$0.01	$50.9
2029	$55.1	$0.01	$55.1
2030	$55.4	$0.01	$55.4
2031	$53.9	$0.01	$53.9
2032	$54.3	$0.01	$54.3
2033	$50.9	$0.01	$50.9
2034	$47.5	$0.01	$47.5
2035	$48.7	$0.01	$48.7
2036	$46.3	$0.01	$46.3
2037	$46.5	$0.01	$46.5
2038	$46.4	$0.01	$46.4
2039	$431	$0.01	$431
2040	$40.2	$0.01	$40.2
Annualized Value Over the 2020-2040 Period	**$1,101**	**$0.24**	**$1,101**

ALTERNATIVE 4

EXHIBIT G-10. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 4, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$34,000,000	$3,300,000	$3,300	$37,000,000
	UG	$2,000,000	$3,800,000	$5,500	$5,800,000
Colorado Plateau	Surface	$5,000,000	$160,000	$1,600	$5,200,000
	UG	$140,000	$88,000	$1,100	$230,000
Gulf Coast	Surface	$11,000,000	$410,000	$3,100	$11,000,000
Illinois Basin	Surface	$19,000,000	$760,000	$1,800	$20,000,000
	UG	$0	$320,000	$6,000	$320,000
Northern Rocky Mountains and Great Plains	Surface	$9,500,000	$240,000	$29,000	$9,800,000
Northwest	Surface	$140,000	$23,000	$120	$160,000
Western Interior	Surface	$780,000	$31,000	$73	$810,000
	UG	$0	$630	$6	$640
Total U.S. Compliance Cost Impacts	Surface	$79,000,000	$4,900,000	$39,000	$84,000,000
	UG	$2,200,000	$4,200,000	$13,000	$6,400,000
	TOTAL	**$81,000,000**	**$9,100,000**	**$52,000**	**$90,000,000**
Note: Totals may not sum due to rounding.					

EXHIBIT G-11. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 4, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$68.7	$0.02	$68.7
2021	$61.4	$0.01	$61.4
2022	$46.2	$0.01	$46.2
2023	$53.6	$0.01	$53.6
2024	$68.2	$0.01	$68.2
2025	$57.4	$0.01	$57.5
2026	$58.6	$0.01	$58.6
2027	455.1	$0.01	455.1
2028	$51.8	$0.01	$51.8
2029	$55.9	$0.01	$55.9
2030	$56.2	$0.01	$56.2
2031	$54.6	$0.01	$54.6
2032	$54.9	$0.01	$55.0
2033	$51.6	$0.01	$51.6
2034	$48.1	$0.01	$48.2
2035	$49.4	$0.01	$49.4
2036	$46.9	$0.01	$46.9
2037	$47.1	$0.01	$47.1
2038	$47.0	$0.01	$47.0
2039	$43.6	$0.01	$43.6
2040	$40.7	$0.01	$40.7
Annualized Value Over the 2020-2040 Period	**$1,117**	**$0.24**	**$1,117**

ALTERNATIVE 5

EXHIBIT G-12. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 5, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$24,000,000	$3,300,000	$3,300	$27,000,000
	UG	$2,000,000	$3,800,000	$5,500	$5,800,000
Colorado Plateau	Surface	$0	$0	$0	$0
	UG	$0	$0	$0	$0
Gulf Coast	Surface	$0	$0	$0	$0
Illinois Basin	Surface	$0	$0	$0	$0
	UG	$0	$0	$0	$0
Northern Rocky Mountains and Great Plains	Surface	$0	$0	$0	$0
Northwest	Surface	$0	$0	$0	$0
Western Interior	Surface	$0	$0	$0	$0
	UG	$0	$0	$0	$0
Total U.S. Compliance Cost Impacts	Surface	$24,000,000	$3,300,000	$3,300	$27,000,000
	UG	$2,000,000	$3,800,000	$5,500	$5,800,000
	TOTAL	**$26,000,000**	**$7,100,000**	**$8,800**	**$33,000,000**
Note: Totals may not sum due to rounding.					

EXHIBIT G-13. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 5, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$10.3	$0.01	$10.3
2021	$4.5	$0.01	$4.5
2022	($8.8)	$0.01	($8.8)
2023	$0.1	$0.01	$0.1
2024	$16.2	$0.01	$16.2
2025	$7.5	$0.01	$7.5
2026	$9.9	$0.01	$9.9
2027	$8.1	$0.01	$8.2
2028	$6.4	$0.01	$6.4
2029	$12.4	$0.01	$12.4
2030	$14.5	$0.01	$14.5
2031	$14.9	$0.01	$14.9
2032	$17.0	$0.01	$17.0
2033	$15.1	$0.01	$15.1
2034	$13.2	$0.01	$13.2
2035	$16.0	$0.01	$16.0
2036	$14.6	$0.01	$14.6
2037	$16.1	$0.00	$16.1
2038	$17.3	$0.00	$17.3
2039	$15.7	$0.00	$15.7
2040	$14.6	$0.00	$14.7
Annualized Value Over the 2020-2040 Period	**$236**	**$0.13**	**$236**

ALTERNATIVE 6

EXHIBIT G-14. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 6, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$7,300,000	$1,500,000	$3,300	$8,800,000
	UG	$0	$3,700,000	$5,500	$3,700,000
Colorado Plateau	Surface	$530,000	$51,000	$1,600	$580,000
	UG	$0	$82,000	$1,100	$83,000
Gulf Coast	Surface	$890,000	$140,000	$3,100	$1,000,000
Illinois Basin	Surface	$16,000,000	$250,000	$1,800	$16,000,000
	UG	$0	$300,000	$6,000	$310,000
Northern Rocky Mountains and Great Plains	Surface	$910,000	$79,000	$29,000	$1,000,000
Northwest	Surface	$39,000	$14,000	$120	$53,000
Western Interior	Surface	$660,000	$11,000	$73	$670,000
	UG	$0	$600	$6	$600
Total U.S. Compliance Cost Impacts	Surface	$26,000,000	$2,100,000	$39,000	$28,000,000
	UG	$0	$4,100,000	$13,000	$4,100,000
	TOTAL	**$26,000,000**	**$6,200,000**	**$52,000**	**$33,000,000**

Note: Totals may not sum due to rounding.

EXHIBIT G-15. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 6, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$11.2	$0.02	$11.2
2021	$5.4	$0.01	$5.4
2022	($8.2)	$0.01	($8.2)
2023	$0.5	$0.01	$0.5
2024	$16.3	$0.01	$16.3
2025	$7.4	$0.01	$7.5
2026	$9.7	$0.01	$9.7
2027	$7.8	$0.01	$7.8
2028	$6.0	$0.01	$6.0
2029	$11.7	$0.01	$11.8
2030	$13.8	$0.01	$13.8
2031	$13.8	$0.01	$13.8
2032	$15.7	$0.01	$15.8
2033	$13.7	$0.01	$13.7
2034	$11.7	$0.01	$11.7
2035	$14.6	$0.01	$14.6
2036	$13.4	$0.01	$13.4
2037	$15.0	$0.01	$15.0
2038	$16.4	$0.01	$16.4
2039	$15.0	$0.01	$15.0
2040	$14.0	$0.01	$14.0
Annualized Value Over the 2020-2040 Period	**$225**	**$0.24**	**$225**

ALTERNATIVE 7

EXHIBIT G-16. SUMMARY OF ANNUALIZED INDUSTRY AND GOVERNMENT COMPLIANCE COSTS UNDER ALTERNATIVE 2, THREE PERCENT DISCOUNT RATE (2014 DOLLARS)

COAL REGION	MINE TYPE	INDUSTRY OPERATIONAL COSTS	INDUSTRY ADMINISTRATIVE COSTS	GOVERNMENT ADMINISTRATIVE COSTS	TOTAL COSTS
Appalachia	Surface	$32,000,000	$2,900,000	$3,300	$35,000,000
	UG	$2,000,000	$3,800,000	$5,500	$5,800,000
Colorado Plateau	Surface	$2,700,000	$94,000	$0	$2,800,000
	UG	$84,000	$53,000	$0	$140,000
Gulf Coast	Surface	$1,700,000	$82,000	$0	$1,800,000
Illinois Basin	Surface	$2,900,000	$76,000	$0	$3,000,000
	UG	$0	$32,000	$0	$32,000
Northern Rocky Mountains and Great Plains	Surface	$1,500,000	$49,000	$0	$1,500,000
Northwest	Surface	$14,000	$2,300	$0	$16,000
Western Interior	Surface	$120,000	$3,100	$0	$120,000
	UG	$0	^63	$0	$63
Total U.S. Compliance Cost Impacts	Surface	$41,000,000	$3,200,000	$3,300	$44,000,000
	UG	$2,100,000	$3,900,000	$5,500	$6,000,000
	TOTAL	**$43,000,000**	**$7,100,000**	**$8,800**	**$50,000,000**

Note: Totals may not sum due to rounding.

EXHIBIT G-17. ANNUAL WELFARE EFFECTS OF ALTERNATIVE 7, THREE PERCENT DISCOUNT RATE (2014 MILLION DOLLARS)

YEAR	WELFARE LOSS - COAL MARKET [A]	GOVERNMENT COST [B]	TOTAL WELFARE LOSS [C]= A+B
2020	$27.1	$0.01	$27.1
2021	$20.9	$0.01	$21.0
2022	$7.0	$0.01	$7.0
2023	$15.6	$0.01	$15.6
2024	$31.4	$0.01	$31.4
2025	$22.0	$0.01	$22.0
2026	$24.2	$0.01	$24.2
2027	$22.0	$0.01	$22.0
2028	$19.8	$0.01	$19.8
2029	$25.2	$0.01	$25.3
2030	$26.8	$0.01	$26.9
2031	$26.8	$0.01	$26.8
2032	$28.4	$0.01	$28.4
2033	$26.1	$0.01	$26.1
2034	$23.7	$0.01	$23.7
2035	$26.0	$0.01	$26.0
2036	$24.3	$0.01	$24.3
2037	$25.4	$0.00	$25.4
2038	$26.1	$0.00	$26.1
2039	$23.8	$0.00	$23.8
2040	$22.3	$0.00	$22.3
Annualized Value Over the 2020-2040 Period	**$495**	**$0.13**	**$495**

ALTERNATIVE 9

Alternative 9 represents a scenario equivalent to the baseline and therefore is associated with no additional costs or benefits.