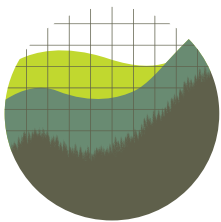




Illuminating the Hidden Costs of Coal

*How the Interior Department Can Use Economic Tools
to Modernize the Federal Coal Program*



Institute for
Policy Integrity

NEW YORK UNIVERSITY SCHOOL OF LAW

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Jayni Foley Hein
Peter Howard, Ph.D.

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Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street
New York, New York 10012

Jayni Foley Hein is the policy director and Peter Howard is the economics director at the Institute for Policy Integrity at NYU School of Law. This report does not necessarily reflect the views of NYU School of Law, if any.

Foreword

Federal coal leasing policy has a long and tortured history. At its core, it is a story about government reform efforts that repeatedly go awry because of the coal industry's success at staying at least one step ahead of the government over many decades and through many iterations of reform. Early on the problems included monopoly power, hoarding but then not developing federal coal resources, and an antipathy for adequate reclamation standards. The most persistent problem, however, has been the government's failure to establish a competitive leasing system that would secure a fair return for the public's coal.

Coal leasing currently occurs under rules adopted in 1982 and those rules established a sensible program that was designed to ensure a robust federal role, particularly in major federal coal production regions like the Powder River Basin of Wyoming and Montana. But the rules contain a loophole that the coal industry quickly understood could be used to turn those rules on their head. If the industry could convince state and federal officials that federal coal resources were not located in "coal production regions" then the leasing system that was designed to be managed proactively by the federal government could instead be turned into a system driven by the industry. Before long all six of the original coal production regions—including the Powder River Basin, one of the largest coal production regions in the world—were "decertified." This allowed the industry to decide when and where they would develop federal coal. Even more importantly, it meant that the industry could effectively lease whatever coal they wanted without competition and at a price they were willing to pay. Billions of tons of coal were sold under this system for pennies per ton, even though the end user of that coal might pay \$40 per ton or more. The coal companies must also pay royalties on federal coal but those royalties are paid on a mine-mouth price that might be far less than the value of that coal on the open market. The state and federal governments, which share these revenues more or less equally, have lost billions of dollars as a result of this system. Perhaps even more tragically, these wrong-headed practices have subsidized an industry that is more responsible than any other for our growing climate crisis.

After much lobbying by conservation groups, good government advocates, and policy leaders, the Interior Department has announced that they are considering reforms. Thankfully, the Institute for Policy Integrity at the NYU School of Law has weighed into the debate with a compelling new report that promotes common sense, market-based reforms to the federal coal leasing program. *Illuminating the Hidden Costs of Coal* by Jayni Foley Hein and Peter Howard describes in detail five specific economic strategies that the authors believe could help the government meet its statutory obligation to achieve a fair return for the public's coal resources. The Interior Department would do well to heed the advice from this important new report from an organization that has been at the forefront of the coal policy debate. That would go a long way to restoring public confidence in the federal coal leasing program.

Mark Squillace
Professor of Law
Director, Natural Resources, Water, and Public Lands Program
University of Colorado Law School

Executive Summary

The U.S. Department of the Interior (“Interior”) can modernize the federal coal program through straightforward fiscal reform. Coal mining on federal lands accounts for more than 40 percent of all coal produced in the United States.¹ Nearly 90 percent of federally-produced coal comes from strip mines in the Powder River Basin in Wyoming and Montana.²

As our October 2015 report described in detail, the federal coal leasing program suffers from lack of robust competition; stagnant minimum bids and royalty rates that have not been raised since 1982; frequent royalty rate deductions; and inconsistent internal “fair market value” calculations, which often fail to account for coal’s export value.³ Further, recent investigations have shown that coal companies exploit loopholes, including royalty rate deductions and lax oversight, to avoid paying their fair share of royalties, costing taxpayers up to \$1 billion each year in lost revenue.⁴ The fiscal terms of federal coal leases also fail to account for the many environmental and social externalities (or shared costs) imposed on the public by coal production.

In managing federal lands, Interior has the obligation and statutory authority to earn a fair return for the American public and protect the environment. The Federal Land Policy and Management Act requires that Interior harmonize energy production with environmental preservation, and manage public lands in accordance with the principles of “multiple use” and “sustained yield.”⁵ The Act also requires that Interior earn “fair market value” for the extraction of coal from public lands.⁶

This report aims to illuminate some of the hidden costs of coal production, which Interior should account for in order to modernize the federal coal program and earn a more fair return. If Interior had used a higher royalty rate that accounts for even a fraction of the public costs of mining, it could have earned an additional \$2 billion from 2009 to 2013, from coal production in four western states—Wyoming, Colorado, Montana, and Utah.⁷

To modernize the coal program and earn a more fair return, Interior should:

- **Increase royalty rates for federal coal to account for the environmental costs of coal production, which are imposed on the public.**

For example, Interior should increase the minimum royalty rate from 12.5 to 18.7 percent for Powder River Basin surface-mined coal, in order to account for the climate change damage caused by methane emissions. (See Table 1). If Interior had used this rate from 2009 through 2013, it could have earned up to an additional \$1.2 billion in total revenue from Powder River Basin coal, alone. (See Table 2).

- **Consider increasing coal royalty rates even higher, to account for transportation externalities.**

Transporting coal long distances by rail generates air pollution and additional greenhouse gas emissions, and contributes to public fatalities, congestion, and noise pollution. Accounting for both methane and transportation externality costs would justify adding 70.1 percent to the current 12.5 percent surface-mine royalty rate for Powder River Basin coal, leading to a new rate of 82.6 percent. (See Table 3).

- **Revise its royalty rate reduction and transportation allowance regulations, to provide better incentives to coal companies.**

Interior should eliminate inefficient and market-distorting subsidies and royalty rate deductions, and instead use its discretion to provide incentives for coal companies to capture more pollution.

- **Increase minimum bids to account for inflation, fixed external costs, and option value, or the informational value of delay.**

Increasing the minimum bid for coal leases will help overcome persistent problems with uncompetitive leasing and inconsistent, internal “fair market value” calculations, both of which hinder a more robust return for taxpayers.

Environmental organizations, fiscal reform advocates, and outdoor recreation groups have recently found common ground in calling for updates to the federal coal program, as increasing the public share of revenue from federal coal production advances mutually reinforcing goals: earning a more fair share for taxpayers and requiring coal companies to pay for some of the environmental and social externalities of coal production. Because coal revenue is split nearly evenly with the states in which production occurs, a greater share of public revenue from federal coal production would help support federal and state conservation measures, infrastructure improvements, climate preparedness, and education, among other public programs.⁸ Environmental and social externalities have historically been cited as justification for federal and state royalties and royalty share agreements, providing a rational basis for accounting for these costs in royalty reform.

As the United States makes progress on climate change policies to reduce domestic greenhouse gas emissions from electric utilities, transportation, buildings, and other sources, it should also take reasonable steps to reduce pollution from fossil fuel production on federal lands. Methane emissions from all coal mines in the United States account for about 13 percent of U.S. methane emissions.⁹ Adjusting the fiscal terms of coal leases to recoup some of the costs of this pollution, and creating incentives for operators to capture more methane, are practical solutions to addressing this potent climate change pollutant in the near term.¹⁰ Closing royalty reduction loopholes and increasing minimum bids would further improve the federal coal program. All of these reforms would help Interior uphold its requirement to balance energy production with environmental preservation, and earn fair market value for the public.

Part I. The Federal Coal Program Should Be Modernized to Earn a Fair Share for Taxpayers, as the Law Requires.

In managing federal lands, Interior has the obligation and statutory authority to both earn a fair return for the American public and protect the environment.

Interior's Dual Mandate

Interior is tasked with the dual mandate to harmonize energy production with environmental preservation, including long-term protection of wildlife habitat and ecosystems. Enacted in 1976, the Federal Land Policy and Management Act provides that federal lands are to be used only for the advancement of the national interest.¹¹ The Act declares that:

[P]ublic lands be managed in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values; that, where appropriate, will preserve and protect certain public lands in their natural condition; that will provide food and habitat for fish and wildlife and domestic animals; and that will provide for outdoor recreation and human occupancy and use.¹²

The Act sets forth the dual mandate of development and preservation. Agencies must both protect the environment¹³ and manage federal lands in such a way as to provide for domestic sources of “minerals [including hydrocarbon energy resources], food, timber, and fiber.”¹⁴

The Act also requires agencies to develop land use plans, and to manage public lands in accordance with the “principles of multiple use and sustained yield.”¹⁵ The Act defines “multiple use” as:

[T]he management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; . . . *the use of some land for less than all of the resources*; a combination of balanced and diverse resource uses that takes into account the *long-term needs of future generations for renewable and nonrenewable resources*, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values.¹⁶

The Act defines “sustained yield” as “the achievement and maintenance in perpetuity of a high-level annual or regular periodic output of the various renewable resources of the public lands consistent with multiple use.”¹⁷ In line with this attention to environmental values, the Act also tasks Interior with “tak[ing] any action necessary to prevent unnecessary or undue degradation of the lands.”¹⁸

Interior's Fair Market Value Requirement

Interior also has a statutory duty to earn “fair market value” for the rights that it conveys to private parties. The Federal Land Policy and Management Act requires that the United States “receive fair market value of the use of the public lands and their resources unless otherwise provided for by statute.”¹⁹ The term “fair market value” is not defined in the statute itself. In 1982—the last time that Interior convened a working group to comprehensively review its “fair market value” procedures—the task force determined that “fair market value” was not merely the value of the resource discovered or produced, but the value of “the right” to explore and, if there is a discovery, to develop and produce the energy resource.²⁰ The statute describes the value of using the lands, and not solely the value of the resources.

The Mineral Leasing Act of 1920, in contrast, does not contain an explicit “fair market value” requirement. Instead, it calls for payment of royalties for “the privileges of mining or extracting the coal in the lands covered by the lease.”²¹ Further, it states that the Secretary of the Interior can include coal, oil, or gas lease terms that she or he deems necessary “to insure the sale of the production of such leased lands to the United States and to the public at reasonable prices, for the protection of the interests of the United States, for the prevention of monopoly, and for the safeguarding of the public welfare.”²²

In the early 1970s, to address growing concerns regarding speculative leasing and failure to obtain fair value, Congress enacted the Federal Coal Leasing Amendments Act of 1976, which amended the Mineral Leasing Act to require competitive bids and to specify that no bid may be accepted which is less than “the fair market value, as determined by the Secretary, of the coal subject to the lease.”²³ The Act established diligent development requirements to reduce speculation and instituted minimum royalty rates of 12.5 percent of the gross value of the coal produced from surface mines, and 8 percent for coal produced from underground mines.²⁴ This language replaced more flexible language in the Mineral Leasing Act that had authorized the Secretary to negotiate lease sales.

The Mineral Leasing Act directs Interior to collect three types of payment from leaseholders: an initial lease bid (or “bonus bid”) payment for the right to mine coal on federal lands; annual rental payments of \$3 per acre; and royalties paid on the value of coal that is mined.²⁵ Interior and its Bureau of Land Management (“BLM”) have broad authority to set the fiscal terms of these payments. Bonus bids, rental payments, and royalties are paid to the U.S. Treasury, and 49 percent of that revenue is returned to the states where production takes place.²⁶

Fair market value is defined in BLM’s economic valuation handbook as “the amount in cash, or on terms reasonably equivalent to cash, for which, in all probability, the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.”²⁷

Interior, as the owner and steward of public lands for present and future generations, should be compensated for the costs to American taxpayers of mining on public lands due to externalities—including climate change impacts, local air pollution, threats to water quality and supply, habitat disruption, noise pollution, and more. These externalities impose costs on local communities close to coal mines; on current and future visitors to public lands seeking recreation, wildlife, or scenic beauty; and on current and future taxpayers who will bear the cost of mitigating and adapting to climate change pollution for decades to come. Indeed, where an externality is not otherwise addressed by federal law, failure to account for the cost of this externality amounts to a subsidy for coal companies.

Methane emissions from coal mines, for example, are not regulated by federal law. Using economic tools like the Social Cost of Methane, we can estimate the cost of these methane emissions to society.²⁸

Accounting for these costs would help Interior uphold its dual mandate to harmonize production with preservation, and to set lease terms necessary to earn fair market value.²⁹ A robust definition of fair market value, then, should include: the market price of the coal resource; the social cost of mining—the cost to American taxpayers of mining on public lands due to non-internalized externalities; and the option value, or the informational value of delay, of mining that resource (described in Part V).

Part II. Interior Should Raise the Royalty Rate for Federal Coal Leases to Account for the Environmental and Social Costs of Coal Production.

Interior should increase its royalty rates for federal coal to account for the environmental externalities associated with coal production, which currently impose uncompensated costs on the public. Accounting for the cost of just one major coal production externality—methane emissions—would justify an increase in both surface and underground coal royalty rates. Because environmental externalities vary with the amount of coal that is produced, these costs are best recouped through the royalty rate.³⁰ Coal production methane emissions stem directly from mining on public lands, and are not otherwise regulated by federal law.³¹

The federal government uses widely accepted economic tools—such as EPA’s Social Cost of Carbon and Social Cost of Methane—to quantify the environmental and social costs associated with certain environmental impacts, such as greenhouse gas emissions.³² The Social Cost of Carbon was designed by an Interagency Working Group comprised of economic and scientific experts from the White House and multiple federal agencies. It was developed through an open and transparent process, and uses the latest peer-reviewed science and economic models.³³ EPA’s Social Cost of Methane builds on this framework and is also based on the latest peer-reviewed science.³⁴ EPA has used the Social Cost of Methane in two proposed rules in 2015, thus far.³⁵ Interior should use these economic tools when evaluating the “fair market value” of coal production on federal lands and setting royalty rates.

Accounting for Coal Production Externalities

Interior would be justified in increasing the current 12.5 percent statutory minimum royalty rate for Powder River Basin surface-mined coal by additional 6.2 percent, leading to a new rate of 18.7 percent. (*See Table 1*). This adjustment uses average externality cost calculations for Powder River Basin coal, and current Wyoming mine-mouth coal prices. This increased rate can be applied to new leases, modified leases, and lease extensions.³⁶ If Interior had used the 18.7 percent royalty rate from 2009 through 2013, it could have earned up to an additional \$1.2 billion in total revenue from Powder River Basin coal.³⁷

This estimate use emission and price data from the U.S. Energy Information Administration (“EIA”) and EPA’s Social Cost of Methane, which has been used to justify and set the stringency of federal rules.³⁸ Because the Social Cost of Methane rises over time, as methane is a stock pollutant, the royalty rate should also increase over time. (*See Table 4*).

For underground coal basins, such as the Uintah Basin in Colorado and Utah, methane emissions are greater. (See *Appendices A and B*). Interior would be justified in raising the current 8 percent federal royalty rate by an additional 20.7 percent, leading to a new rate of 28.7 percent. (See *Table 1*). This adjustment, specific to the Uintah Basin, is based on current production-weighted prices for Colorado and Utah.

If Interior had used these suggested surface and underground royalty rates for federal coal produced in four Western states—Wyoming, Colorado, Montana, and Utah—it could have earned an additional \$2 billion, between 2009 and 2013. (See *Appendix B, Table B13*). Accounting for the benefits to the U.S. public in terms of increased revenue and decreased externalities from coal mining, this increase would have provided \$2.9 billion in additional benefits from 2009 to 2013.³⁹

These estimates represent conservative lower bounds for externality costs, for several reasons. First, the only environmental externality quantified is methane emissions from coal production. This omits other known externalities including emissions of volatile organic compounds and hazardous air pollutants, water pollution, water use, habitat disruption, and noise. (See *Appendices A and B*). Some of these externalities are more difficult to quantify, as their cost varies depending on location, unlike methane, which is a global greenhouse gas pollutant. As federal agencies refine techniques to quantify these externalities, ideally they should be included in royalty rate assessments, or otherwise addressed by regulation. Second, the Social Cost of Methane, itself, omits certain damages and represents a lower-bound estimate of the cost of methane emissions.⁴⁰ Third, these estimates do not account for the value of the marketable natural gas that is lost when methane escapes into the atmosphere.⁴¹ Furthermore, these values do not account for the significant transportation externalities associated with transporting federal coal long distances using freight rail, or for the downstream greenhouse gas emissions emitted when coal is burned.⁴²

Finally, one caveat to our suggested royalty rate increases is that in order for any royalty rate adjustment to increase public revenue, the bonus bid that companies pay to secure a lease cannot be lowered to compensate for a royalty rate increase. Thus, if Interior raises royalty rates, it should also advise BLM regional offices to keep their internal fair market value calculations in line with current levels, and to reject all bids lower than the internal appraised fair market value.

Accounting for Coal Transportation Externalities

In Wyoming, approximately 90 percent of federal coal is transported by rail out of the state, mostly for end use in power plants.⁴³ Transportation by rail causes multiple externalities including greenhouse gas emissions, emission of particulate matter and other air pollutants, increased fatalities and risks to public health due to accidents, and congestion and noise.⁴⁴ Interior would be justified in raising the royalty rate for federal coal leases substantially higher than the 18.7 and 28.7 percent surface and underground rates, respectively, provided above, in order to account for the environmental and social costs of transporting coal by rail.

We estimated the cost of rail transportation impacts, using available data and economic literature. Accounting for both methane and transportation externality costs would justify adding 70.1 percent to the current 12.5 percent surface-mine royalty rate, for Powder River Basin coal. (See *Table 3; Appendices A and B*). This would justify a new royalty rate of 82.6 percent for federal surface-mined coal. In other words, coal transportation externalities impose significant public costs. These values illuminate the extent of federal coal production's societal costs. As discussed in Part III, these transportation externalities also justify a change to existing regulations that are designed to generously subsidize coal transport.

In short, our methane emission and transportation externality cost assessments reveal the hidden costs of federal coal production. Economic and scientific understanding of these costs has markedly improved in the 95 years since the passage of the Mineral Leasing Act. Armed with the knowledge that greenhouse gas emissions and other pollution from coal production impose significant costs on society, as well as the tools to measure these costs, Interior should account for these costs through royalty reform. By making these changes, Interior can earn fair market value and manage public lands for the benefit of current and future generations. American taxpayers need not be saddled with all of the environmental costs of coal production.

Part III. Interior Should Revise Its Transportation Allowance and Royalty Rate Reduction Regulations, to Provide Better Incentives to Coal Companies.

Current regulations allow for unlimited transportation deductions, when royalties are calculated using the market price of coal.⁴⁵ As a practical matter, this transportation deduction is used sparingly, as most companies sell their coal at the mine mouth, making transportation costs irrelevant to royalty assessments. However, if Interior changes the point of valuation for coal royalties to the final delivery point (market price) or another point remote from the mine, as the Office of Natural Resources Revenue is considering,⁴⁶ transportation costs will become relevant to royalty payments. In such a scenario, the transportation deduction would translate into an allowance for the full cost of transporting coal from the mine to a remote point of sale, reducing incentives for companies to find the most efficient and lowest-cost mode of transportation, and subsidizing coal production and transportation over other energy sources.

If the point of valuation changes, this transportation allowance should be eliminated. As noted above, there are significant externality costs associated with transporting coal from the Powder River Basin to end users by rail, including greenhouse gas and other air emissions, fatalities, and congestion. (See Table 3). In addition, if Interior changes the manner in which royalties are calculated to use the market sale price—a change that would likely increase transparency and public revenue⁴⁷—a royalty rate increase that accounts for externality costs should be based on the average U.S. price for coal delivered to the electric power sector, as opposed to the state mine mouth price. We provide these values in Table 1.

Interior's Royalty Rate Reduction Regulations Should Be Revised

Interior should also revise its royalty rate reduction regulations. Currently, BLM has discretion to grant royalty rate reductions if the rate reduction: (i) encourages the greatest ultimate recovery of the coal resource; (ii) is in the interest of conservation of the coal and other resources; (iii) is necessary to promote development of the coal resource; or (iv) if the federal lease cannot be successfully operated under its terms.⁴⁸ Royalty rate reductions occurred on approximately 36 percent of leases offered for sale since 1990.⁴⁹ These reductions distort the energy market by subsidizing coal production, even when it is uneconomical.

It is not rational for the federal government to support uneconomical coal production; this runs counter to its “fair market value” mandate. This regulation should be revised to remove duplicative and inefficient provisions. In addition, if Interior raises royalty rates in accord with our recommendations, Interior could revise this regulation to allow for negotiating lower rates for coal lessees that demonstrate that they capture more methane than average surface or underground mines. This would allow Interior to raise royalty rates uniformly (as described above), and reward lessees that reduce more greenhouse gas pollution than the national average for surface and underground coal production.

Part IV. Interior Has Discretion to Make these Changes Now, Through Either a Rulemaking or by Issuing Guidance to BLM Regional Offices.

Interior can raise the royalty rate for surface-mined coal either through a rulemaking (to raise the 12.5 percent royalty rate floor in its regulations) or through guidance to regional offices.⁵⁰ The royalty rate for underground coal is set at 8 percent by regulation.⁵¹ Interior has discretion to raise this rate, but would need to revise this regulation through rulemaking in order to do so.⁵² For both types of federal coal, any new royalty rate could be applied to new leases, as well as to any approved modification or extension of existing leases.⁵³ In any potential legal challenge, Interior’s actions would be reviewed according to the Administrative Procedure Act’s “arbitrary and capricious” standard, which requires a rational basis for agency action.⁵⁴

Revising Royalty Rates through Rulemaking

In order to raise both surface and underground royalty rates at the same time, Interior would need to initiate a notice-and-comment rulemaking and propose revised coal royalty regulations. Interior could propose increasing the royalty rate floor for both surface and underground coal. For underground coal regulation, Interior should also set the revised rate as a floor, and not a set rate (as under the current regulation), so that BLM would gain discretion to raise that rate on a case-by-case basis, as it can already do for surface-mined coal.

Conducting a rulemaking and finalizing new regulations would allow for public comment and would result in more durable change. Further, Interior would be able to propose changes to its current royalty rate reduction and transportation allowance regulations in the same rulemaking. A primary drawback of enacting reforms through a rulemaking is the length of time and agency resources necessary to complete the process.

Revising Royalty Rates through Guidance

As an alternative to rulemaking, Interior could issue guidance to BLM regional offices, requesting that they use higher royalty rates to account for the average externality costs of coal production in their regions. A benefit of this approach is expediency: Interior could issue this guidance without going through the public notice-and-comment process and its at-

tendant requirements and comment periods. Another potential benefit is that this guidance could more easily be updated, for example, to account for revised externality cost estimates as quantification and measurement techniques improve.

A significant drawback of using guidance instead of a rulemaking is the relative impermanence of guidance; Interior could easily withdraw or modify the guidance, unlike a final rule, which would require another rulemaking to amend. A further drawback is that BLM regional offices would retain some discretion, pursuant to existing regulations, to issue royalty rate reductions in a manner that may impair the efficacy of a rate increase.⁵⁵ Further, because lease sale terms are set by BLM regional offices (unlike for offshore drilling, for example, where the Bureau of Ocean Energy Management (BOEM) sets lease sale terms), regional offices would retain some discretion to diverge from Interior's suggested royalty rate increases, as long as their decision to do so was not arbitrary or capricious.

Interior Has Significant Discretion to Raise Royalty Rates and Modify Rate Reduction Regulations

Interior has significant discretion to raise royalty rates, whether by rulemaking or guidance. In any potential legal challenge, the appropriate standard of review would be the “arbitrary and capricious” standard under section 706(2)(A) of the Administrative Procedure Act.⁵⁶ This standard is generally deferential to agency decisions, and has been described by reviewing courts as requiring a finding of “reasonableness” or a “rational basis” for the agency action.⁵⁷ A reviewing court may not substitute its judgment for that of the agency; rather, the court is restricted to deciding whether the agency could reasonably have taken the action in question. A reviewing court would consider whether the decision was based on a consideration of the relevant factors and whether there has been a clear error of judgment.⁵⁸

As a threshold matter, the relevant statutes do not preclude Interior from considering environmental and social costs when setting coal lease fiscal terms. The relevant statutory provision governing royalty rates states that: “[a] lease shall require payment of a royalty in such amount as the Secretary shall determine.”⁵⁹ The Federal Coal Leasing Amendments Act of 1976 also provides that “the lease shall include such other terms and conditions as the Secretary shall determine.”⁶⁰ Further, the statutory text detailing the leasing process provides little guidance on what factors may be considered when setting fiscal terms (aside from “fair market value”).⁶¹ The statutory text also provides for consideration of environmental impacts in leasing decisions, in provisions separate from the discussion of fiscal terms.⁶²

Interior's decision to raise royalty rates in order to account for externality costs would likely be entitled to deference, as the agency has particular expertise in the stewardship and valuation of federal natural resources.⁶³ While increasing royalties to account for environmental impacts would be a policy shift, this, alone, is not compelling evidence that doing so would violate the Administrative Procedure Act.⁶⁴ No federal cases have dealt with this specific issue; however, in *California v. Watt* (“Watt II”), the D.C. Circuit held that Interior has discretion to change how it manages federal leasing in order to ensure receipt of “fair market value,” and that the fair market value requirement “does not mandate the maximization of revenues, it only requires receipt of a fair return.”⁶⁵ Here, in a similar vein, Interior would be altering the fiscal terms of leases, to ensure receipt of fair market value.

There is a strong argument that accounting for the cost of environmental and social externalities to justify a royalty rate increase, or to modify rate reduction regulations, falls within Interior's discretion and expertise, and aligns with its past practices. One of the long-standing rationales for royalty payments is to compensate landowners (including states and the federal government) for foreseeable social and environmental impacts.⁶⁶ Environmental and social externalities have

been consistently cited as a rationale for royalty rate increases and for royalty share agreements between states and the federal government. This explicit, historical link between royalties and environmental externalities bolsters the view that Interior would be acting reasonably if it chooses to make changes in line with our recommendations.

The legislative history of the Federal Coal Leasing Amendments Act of 1976 reflects a concern that states be paid a greater share of federal coal royalties, at least in part, to account for social and environmental externalities: “When an area is newly opened to large scale mining, local governmental entities must assume the responsibility of providing public services needed for new communities, including schools, roads, hospitals, sewers, police protection, and other public facilities, as well as adequate local planning for the development of the community.”⁶⁷ The additional revenue from a larger share of royalties was to be used “as the legislature of the State may direct giving priority to those subdivisions of the State socially or economically impacted by development of minerals leased under this Act for (1) planning, (2) construction and maintenance of public facilities, and (3) provision of public services.”⁶⁸

Further, following the passage of the Gulf of Mexico Energy Security Act in 2006, gulf-producing states (defined as Alabama, Mississippi, Louisiana, and Texas) now receive up to 37 percent of revenues from certain Outer Continental Shelf Gulf leases⁶⁹—up from 27 percent, as previously outlined in the Outer Continental Shelf Lands Act.⁷⁰ Coastal states and their congressional representatives have repeatedly advocated for greater revenue share due to significant impacts on coastal infrastructure and the environment.⁷¹ According to coastal producing states, these revenues are needed to mitigate environmental impacts and to maintain the necessary support structure for the offshore oil and gas industry.⁷² In addition, the Gulf of Mexico Energy Security Act of 2006 directs coastal states to use their share of royalty payments from offshore drilling for “the purposes of coastal protection, including conservation, coastal restoration, hurricane protection, and infrastructure directly affected by coastal wetland losses,” and “[m]itigation of damage to fish, wildlife, or natural resources,” among other delineated uses.⁷³

Moreover, the federal Land and Water Conservation Fund, since its establishment in 1965, has used federal oil and gas revenues to build and maintain public parks and protect open space and trails across the country.⁷⁴ The Fund was designed to ensure that \$900 million per year of these revenues would be allocated to conserving our nation’s natural and cultural heritage and enhancing public outdoor recreational opportunities.⁷⁵ In short, there is an explicit relationship between Interior’s royalty assessments and public compensation for foreseeable environmental, social, and economic impacts.

In addition, Interior would be acting rationally by using modern economic tools, such as the Social Cost of Methane, to help evaluate fair public compensation for the “use of the public lands and their resources.”⁷⁶ As described above, the Social Cost of Carbon is a widely accepted methodology used by several federal agencies to quantify the costs of climate pollution, for the purpose of designing federal rules and programs. Indeed, the Social Cost of Carbon was developed in response to a lawsuit challenging the Department of Transportation’s failure to monetize climate benefits in its economic assessment of vehicle efficiency standards. In a 2008 decision, the federal Court of Appeals for the Ninth Circuit found that, due in part to advancements in “scientific knowledge of climate change and its causes,” the agency’s failure to quantify any climate benefits when conducting its economic analysis was arbitrary and capricious.⁷⁷ The Social Cost of Methane builds on the Social Cost of Carbon framework and represents conservative estimate of methane costs.⁷⁸ Thus, relying on the Social Cost of Methane, while legally untested in this and other contexts, should be found to be a reasonable method by which to quantify the cost of relevant environmental externalities.

Increasing onshore coal rates also aligns with other recent rate adjustments. Between 2007 and 2008, Interior increased offshore oil and gas royalty rates for Gulf of Mexico leases twice—from 12.5 percent to 16.75 percent, and then again to 18.75 percent.⁷⁹ Interior cited the need to earn “fair market value,” as well as market changes and technological advances as the rationale for this change.⁸⁰ Many of these factors are also present for onshore coal. Thus, our recommended rate increases would be consistent with both Interior’s past practice and EPA’s present valuation techniques.

The only potentially significant legal risk to Interior would result from changes that completely or nearly completely eliminated federal coal production. If Interior’s actions led to such a result, litigants could argue that the Federal Land Policy and Management Act’s directive to manage public lands “in a manner which recognizes the Nation’s need for domestic sources of minerals” would preclude such a policy.⁸¹ Interior, for its part, would be able to argue that even if current production were halted entirely, that result would be consistent with the nation’s long term domestic needs, including conservation of non-renewable resource reserves. Further, the Mineral Leasing Act gives the Secretary “discretion” to offer lands for coal leasing, but does not appear to compel it.⁸² Under the *Chevron* doctrine, the agency’s statutory interpretation would be given considerable deference.⁸³ Short of this dramatic effect, a reviewing court would be even more disinclined to unsettle the agency’s judgment.⁸⁴

In sum, because Interior has statutory discretion to increase royalty rates for coal leases and expertise in managing federal leases, a reviewing court would likely be hesitant to substitute its judgment for that of the agency. Environmental and social costs are relevant to the public’s fair share of revenues, as evidenced by federal-state royalty share agreements, legislative history, and other programs that make this link explicit. A reviewing court would likely find that Interior acted reasonably if it adjusts its regulations in accordance with our recommendations or issues comparable guidance to BLM regional offices.

Part V. Interior Should Raise Minimum Bids to Account for Inflation, the Fixed Social Costs of Mining, and Option Value.

In addition to royalty reform, Interior should make changes to its minimum bid regulation and internal fair market value calculations (used to establish adequate bonus bids), to help overcome persistent problems with uncompetitive leasing and inconsistent returns for taxpayers.

In 2013, the Government Accountability Office found that approximately 90 percent of all federal coal lease sales since 1990 attracted only one bidder.⁸⁵ It also determined that BLM’s process for assessing the fair market value of federal coal “lacks sufficient rigor and oversight,” and that BLM’s state offices varied widely in the approaches they use to develop estimates of fair market value.⁸⁶ At the bidding stage, BLM should be compensated for the estimated market price of the coal to be leased, as well as the option value of mining coal (or informational value of delay), as both of these are fixed costs. Making these changes in tandem with royalty reform would help ensure that a greater share of public revenue is realized, as companies would have less latitude to bid lower to compensate for higher royalties. Environmental and social externalities from coal production vary with the amount of coal produced; therefore, these costs are best recouped through royalties, as discussed above.

The minimum bid for coal leasing has been set at \$100 per acre since 1982.⁸⁷ Interior has the authority, pursuant to the Mineral Leasing Act and Federal Coal Leasing Amendments Act, to increase minimum bids. The minimum bid should be raised to account for inflation, fixed social costs, and the option value of leasing, in order to serve as a floor price for fair market value, as originally intended. Accounting for inflation, alone, would raise the minimum bid to \$247 per acre.⁸⁸ BLM should also account for the fixed social costs of mining, such as lost amenities (i.e., lost public access to recreation) and public funding of reclamation, in the minimum bid price. (See Table 5). These are fixed costs, as opposed to variable costs, because they are incurred by the public independent of how much coal is mined. As soon as a tract is leased, the public loses access to it for other purposes, such as recreation or habitat protection. And as soon as companies undertake exploratory mining, the site incurs reclamation costs. While coal companies are supposed to post bonds adequate to pay for the cost of land reclamation upon cessation of mining,⁸⁹ these bonds are overdue for an increase and often fall short of what is required for reclamation.⁹⁰ Using data on the cost of publicly-funded reclamation, alone, we estimate these “fixed costs” of coal leasing to be \$0.44 per metric ton of coal.⁹¹ (See Appendices A and B). Interior should issue guidance to regional offices to add this cost to their internal fair market value calculations, or alternatively, use this cost to justify an increased minimum bid.

BLM’s minimum bid and fair market value appraisals also fail to account for the option value of coal leasing, which is the value of waiting for more information on energy prices and extraction risks before deciding whether and when to lease the public’s energy resources to private companies.⁹² To account for the option value of coal leasing, or the informational value of delay, Interior can look to BOEM’s draft program for offshore leasing for 2017 to 2022 as a starting point.⁹³ BOEM uses a hurdle price analysis to account for economic uncertainty, and qualitatively considers environmental and social option value when determining where and when to lease. As the D.C. Circuit affirmed, there is “a tangible present economic benefit to delaying the decision to drill,” and failing to account for this value undervalues public resources.⁹⁴

While BOEM does not yet quantitatively assess environmental or social option value, BLM should adopt BOEM’s approach to option value as a starting point, and consult with BOEM’s economists and staff about further improving fair market value estimates in order to quantitatively account for option value. Because individual fair market value calculations are done for each lease sale by the BLM regional office where the leasing takes place, Interior should instruct regional offices to incorporate option value into their internal calculations. It can do so by updating its Coal Evaluation Manual and Handbook, without the need to propose a new rulemaking. Or, Interior could revise its current regulations to encourage the use of option value in fair market value appraisals. BLM can use Appendices C and D accompanying this report to help quantify the option value associated with coal leasing. Interior should also consider organizing a working group to further evaluate methods to use and quantify option value for both offshore and onshore natural resources leasing.

Interior should also examine how to conduct more long-term strategic planning for federal coal production, as BOEM does through its five-year program. For example, it should consider reinstating the Powder River Basin’s status as a “coal production region,” to gain greater control over when and where leasing occurs.⁹⁵

In sum, a robust definition of fair market value should include the market price of the coal resource, the option value of mining that resource, and the social and environmental costs of mining. At the bidding stage, BLM should be compensated for the estimated market price of the coal to be leased, as well as the option value of leasing coal.

Conclusion

Federal coal production entails substantial hidden costs, including methane emissions and transportation externalities. Economic and scientific understanding of these costs has markedly improved in the 95 years since the passage of the Mineral Leasing Act, and in the many decades since Interior last updated the fiscal terms for coal leases. Interior should account for these environmental and social costs through royalty reform, in order to earn fair market value and manage public lands for the benefit of future generations. Failure to account for these costs amounts to a subsidy for coal production.

TABLE 1. Suggested Royalty Rate Increases and New Royalty Rates, Based on Net Methane Emission Externality Costs (EIA, 2011) by Region-Mining Type and Geographical Scope of Price

Region	Mining Type	Suggested Increase, Using State Mine-Mouth Price	Suggested Increase, Using Average U.S. Price of Coal Delivered to the Electric Power Sector	Suggested New Royalty Rate (Using State Mine-Mouth Price)
Colorado	Underground	19.5%	16.7%	27.5%
	Surface	2.2%	1.9%	14.7%
Wyoming	Underground	56.0%	16.7%	64%
	Surface	6.2%	1.9%	18.7%
Utah	Underground	22.6%	16.7%	30.6%
	Surface	2.5%	1.9%	15%
Montana	Underground	46.9%	16.7%	54.9%
	Surface	5.2%	1.9%	17.7%
Powder River Basin (Wyoming)*	Underground	–	–	
	Surface	6.2%	1.9%	18.7%
Uinta Basin (Colorado and Utah)**	Underground	20.7%	16.7%	28.7%
	Surface	2.3%	1.9%	14.8%
* The basin is assigned the Wyoming price because Wyoming makes up the majority (approx. 90%) of production.				
** The basin is assigned a production-weighted price of Colorado and Utah.				
*** The middle two columns are suggested royalty rate increases: the first is the royalty rate increase if the state mine-mouth price is used and the second is the royalty rate increase if the average U.S. price of coal delivered to power plants is used. Currently, the mine-mouth price is used to calculate royalty payments. The last column (on the right) is the suggested new royalty rate, based on state mine-mouth prices.				
**** Emissions are measured as net emissions: total methane emissions emitted during mining and from coal pores during transport, less methane captured (based on average emissions captured for each mining type).				

Sources:

- *Methane: Methane Emissions from 2005 to 2009: Table 18 of* http://www.eia.gov/environment/emissions/ghg_report/pdf/0573%282009%29.pdf
- *EIA Production Data from 2005 to 2009: www.eia.gov/totalenergy/data/annual/pdf/sec7_7.pdf and Table 1 of: http://www.eia.gov/coal/annual/pdf/acr.pdf*
- *EPA Estimate of the Social Cost of Methane Used in EPA Cost Benefit Analysis: Marten et al. (2015).*
- *EIA Price Data Averaged from 2009 to 2013—Table 28 (State Price) and 34 (U.S. Electric Power Price) of* <http://www.eia.gov/coal/annual/pdf/acr.pdf>

Methodology:

- EIA emissions data (metric tons) are net U.S. methane emissions by surface and underground coal mines from 2005 to 2009.
- Emissions are divided by EIA's U.S. coal production data (after converting to metric tons) for the corresponding year, and then averaged from 2005 to 2009 to calculate average U.S. methane emissions by mine type.
- We multiply emissions by the social cost of methane in 2015 (2015 USD) to calculate the average external cost of U.S. methane emissions by mine type.
- We divide the average costs of methane emissions by the average sales price of coal at the state level and the average sales price of coal at the U.S. level by mining type (surface or underground).

Interpretation:

- The state royalty rates differ by state due to differing state average sale prices of coal and differing externality costs for surface and underground mines.
- U.S. royalty rates do not differ by state (since the U.S. price is uniform across states), but differ between mining methods due to different externality costs for surface and underground mines.
- We also used both EIA (2011) methane emissions data (2005 to 2009) and EPA (2015) methane emissions data (2009 to 2013) to estimate suggested royalty rate increases, and the results were almost identical. For example, the EPA data implies royalty rate increases in the Powder River Basin of 6% and 1.8%, slightly lower than the 6.2% and 1.9% suggested by the EIA data. We prefer the EIA methane emissions data over the EPA emissions data because we use EIA coal production and price data for our other calculations.

TABLE 2. Lost Government Royalty Revenue (in USD) from Powder River Basin Coal from Using Current 12.5% Statutory Royalty Rate Versus Our Estimated Rate of 18.7% (using U.S. EIA data)

Variable	2013	2012	2011	2010	2009	Sum (USD)
Perfectly Inelastic Supply	290,343,838	309,165,604	331,235,289	324,298,504	312,572,969	\$1,567,616,205
Elasticity of 1	228,203,784	242,997,273	260,343,553	254,891,394	245,675,383	\$1,232,111,389
Elasticity of 3	103,923,675	110,660,609	118,560,080	116,077,175	111,880,217	\$561,101,756

Sources:

- U.S. EIA production and price data. We use Wyoming price data, as the majority of Powder River Basin coal is produced and sold in Wyoming, at the state mine mouth price.
- Elasticities of supply: Haggerty, M., Lawson, M., & Percy, J. (2015). Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for U.S. Coal Used in Power Generation. *Available at SSRN 2627865*.

Interpretation:

- We assume an average elasticity of supply of between 1 and 3 (based on EIA's chosen elasticity of supply for U.S. coal (Haggerty et al., 2015)); this results in lost revenue of between approximately \$1.2 billion and \$600 million. Regional supply elasticity in the Powder River Basin may be more inelastic (lower), making the upper limit on lost revenue about \$1.6 billion.
- These estimates account for inflation, but not discounting. If we were to discount, the resulting estimates would be higher

TABLE 3. Externality Cost Detail and Suggested Royalty Rate Increases in the Powder River Basin

Relevant Category	Low	Best	High	Units	Source
Production					
Methane emissions from mines	\$0.44	\$0.98	\$2.74	2015 USD/ metric ton	Author's estimate using U.S. EIA data
Air pollution, water pollution, and water use	–	–	–	–	–
Transportation					
Fatalities to public due to coal transport	\$1.73	\$2.64	\$9.95	2015 USD/ metric ton	GAO (2011); Epstein et al (2011); Forkenbrock (2001)
GHG emissions from trains	\$0.56	\$1.75	\$5.17	2015 USD/ metric ton	Author's estimate
Air pollution from trains	\$0.16	\$3.18	\$12.00	2015 USD/ metric ton	Forkenbrock (2011); CBO (2015); GAO (2011)
Congestion	\$0.00	\$0.62	\$0.74	2015 USD/ metric ton	CBO (2015); Gorman (2008); Gorman (2008)
Noise	\$0.00	\$1.02	\$1.02	2015 USD/ metric ton	Forkenbrock (2001); Forkenbrock (2001)
Pavement	\$0.00	\$0.80	\$0.96	2015 USD/ metric ton	CBO (2015); CBO (2015)
Total Variable External Costs	\$2.88	\$10.99	\$32.58	2015 USD/ metric ton	–
Royalty Rate Increase - Production Only					
Wyoming mine-mouth price	2.8%	6.2%	17.4%	Externality Royalty Rate	EIA Coal Report – Table 28
Royalty Rate Increase - Production and Transport					
Wyoming mine-mouth price	18.4%	70.1%	207.7%	Externality Royalty Rate	EIA Coal Report – Table 28
Average U.S. price of coal delivered to the electric power sector	5.5%	20.9%	61.9%	Externality Royalty Rate	EIA Coal Report – Table 24

Sources:

- *Methane: Methane Emissions from 2005 to 2009 Using EIA (2011) Data: Table 18 of* http://www.eia.gov/environment/emissions/ghg_report/pdf/0573%282009%29.pdf
- *EIA Production Data:* http://www.eia.gov/totalenergy/data/annual/pdf/sec7_7.pdf and *Table 1 of* <http://www.eia.gov/coal/annual/pdf/acr.pdf>
- *Official EPA Estimate of the Social Cost of Methane Data Used in Recent CBA: Marten et al. (2015)*

TABLE 4. Royalty Rate Increase (Due to Rise in the Social Cost of Methane over Time as Estimated by Marten et al (2015)) and Resulting New Royalty Rate for Surface Mining in the Powder River Basin as a Percentage of the State Price

Year	Increase in the Social Cost of Methane Relative to 2015	Royalty Rate Increase – Surface Mining in the Powder River Basin As a % of State Price	Resulting Royalty Rate
2015	0%	6.2%	18.7%
2020	20%	7.5%	20.0%
2025	40%	8.7%	21.2%
2030	60%	10.0%	22.5%
2035	80%	11.2%	23.7%
2040	100%	12.5%	25.0%
2045	130%	14.3%	26.8%

Interpretation:

- The royalty rates in Table 4 increase over time solely due to the increasing social cost of methane over time as estimated by Marten et al. (2015)—the social cost of methane increases because greenhouse gases are stock pollutants. Implicitly, we assume that real (i.e., accounting for inflation) U.S. coal prices remain constant at their 2009 to 2013 average.

TABLE 5. Fixed Costs of Mining and Suggested Per Metric Ton Minimum Bid Increase in the Powder River Basin (and the United States)

Relevant Category	Low	Best	High	Units	Source
Obtaining Mining Rights					
Amenities	–	–	–	2015 USD/ metric ton	–
Abandoned mine lands (AMLs)	\$0.44	\$0.44	\$0.44	2015 USD/ metric ton	Epstein et al (2011)
Option Value	–	–	–	2015 USD/ metric ton	–
Minimum Bid Increase					
Fixed External Costs	\$0.44	\$0.44	\$0.44	2015 USD/ metric ton	–

Endnotes

- ¹ U.S. ENERGY INFORMATION ADMINISTRATION, Sales of Fossil Fuels Produced from Federal and Indian Lands, FY 2003 through FY 2012 at 4 (June 2014), *available at* <http://www.eia.gov/analysis/requests/federallands/pdf/eia-federallandsales.pdf>.
- ² See U.S. ENERGY INFORMATION ADMINISTRATION, Coal Data Browser, *available at* <http://statistics.onrr.gov/ReportTool.aspx>; DEPT. OF THE INTERIOR, OFFICE OF NATURAL RESOURCES REVENUE, Statistical Information, *available at* <http://statistics.onrr.gov/ReportTool.aspx>; see also Nidhi Thakar and Michael Madowitz, FEDERAL COAL LEASING IN THE POWDER RIVER BASIN, CENTER FOR AMERICAN PROGRESS (2014), *available at* <https://cdn.americanprogress.org/wp-content/uploads/2014/07/ThakarPowderRiver-brief.pdf>.
- ³ Jayni Foley Hein and Peter Howard, RECONSIDERING COAL'S FAIR MARKET VALUE, INSTITUTE FOR POLICY INTEGRITY, NYU SCHOOL OF LAW (Oct. 2015), *available at* http://policyintegrity.org/files/publications/Coal_fair_market_value.pdf.
- ⁴ Tom Sanzillo, THE GREAT GIVEAWAY: AN ANALYSIS OF THE UNITED STATES' LONG-TERM TREND OF SELLING FEDERALLY OWNED COAL FOR LESS THAN FAIR MARKET VALUE, INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS (June 2012), *available at* https://docs.google.com/file/d/0B_qWeYLAqoq1V2YyX3hnR25lcXM/edit. The author conducted independent analysis and found that as a result of policy choices and a subjective fair market value appraisal process, the U.S. Treasury lost almost \$30 billion in revenue from the coal program during the past 30 years.
- ⁵ See 43 USC §1701 et seq.
- ⁶ 43 U.S.C. § 1701(a)(9).
- ⁷ See Appendix B; Table B13.
- ⁸ See 43 U.S.C. § 191(a)-(b); CONGRESSIONAL RESEARCH SERVICE, U.S. AND WORLD COAL PRODUCTION, FEDERAL TAXES, AND INCENTIVES (March 14, 2013), *available at* <https://www.fas.org/sgp/crs/misc/R43011.pdf>.
- ⁹ U.S. EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990–2013 at Table 2-1 (April 15, 2015), *available at* <http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf>.
- ¹⁰ Methane's global warming potential is up to 86 times greater than carbon dioxide in the first 20 years after release, and 34 times more powerful on a 100 year timeframe. IPCC WORKING GROUP I, FIFTH ASSESSMENT REPORT, CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS, CHAPTER 8: ANTHROPOGENIC AND NATURAL RADIATIVE FORCING 633, 711-712, 714 (Table 8.7) (2014), *available at* https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf.
- ¹¹ 43 U.S.C. § 1701(a)(1).
- ¹² 43 U.S.C. § 1701(a)(8).
- ¹³ *Id.*
- ¹⁴ 43 U.S.C. § 1701(a)(12).
- ¹⁵ 43 U.S.C. § 1712(a)-(c)(1).
- ¹⁶ *Id.* § 1702(c) (emphasis added). "Multiple use" is also defined as: "harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output." *Id.*
- ¹⁷ *Id.* (emphasis added).
- ¹⁸ 43 U.S.C. § 1732(b).
- ¹⁹ 43 U.S.C. § 1701(a)(9).
- ²⁰ U.S. GOVERNMENT ACCOUNTABILITY OFFICE, NO. GAO-14-50, OIL AND GAS RESOURCES: ACTIONS NEEDED FOR INTERIOR TO BETTER ENSURE A FAIR RETURN 3 (Dec. 2013), *available at* <http://www.gao.gov/assets/660/659515.pdf>.
- ²¹ Mineral Leasing Act of 1920, Sec. 7, codified as amended at 30 U.S.C. § 207 et seq.
- ²² 30 U.S.C. § 187.

- ²³ Federal Coal Leasing Amendments Act of 1975, Pub. L. No. 94-377, 90 Stat. 1083, 1087 (1976), codified as amended at 30 U.S.C. § 207 et seq.
- ²⁴ 30 U.S.C. §207(a); 43 C.F.R. § 3473.3-2. Implementing regulations were adopted in 1979 and 1982.
- ²⁵ 30 U.S.C. §207(a).
- ²⁶ U.S. Department of Interior, Office of Natural Resources Revenue, Natural Resource Revenues from U.S. Federal Lands, *available at* <https://useiti.doi.gov/>.
- ²⁷ U.S. BUREAU OF LAND MANAGEMENT, NO. H-3070-2, ECONOMIC EVALUATION OF OIL AND GAS PROPERTIES HANDBOOK AT I.C, *available at* http://www.blm.gov/style/medialib/blm/wo/Information_Resources_Management/policy/blm_handbook.Par.39460.File.dat/h3070-2.pdf.
- ²⁸ See Marten A.L., Kopits K.A., Griffiths C.W., Newbold S.C., and Wolverton A., Incremental CH₄ and N₂O Mitigation Benefits Consistent with the US Government's SC-CO₂ Estimates, CLIMATE POLICY 15(2):272-2982014 (2015).
- ²⁹ See 30 U.S.C. § 187.
- ³⁰ In other words, as more coal is produced, more methane is produced. Because royalty rates are assessed on the amount of coal produced, in order to determine total royalties due, it is proper to recoup the cost of externalities by increasing the royalty rate. A close analogy to this approach is a tax on pollution, which applies to the amount of pollution produced.
- ³¹ For example, there is a current proposed rule by the U.S. Environmental Protection Agency ("EPA") to directly regulate methane emissions from oil and gas wells; no such rule exists for coal mines. See 80 Fed. Reg. 56,593 (Sept. 18, 2015) (Oil and Natural Gas Sector: Emission Standards for New and Modified Sources).
- ³² See U.S. EPA, "The Social Cost of Carbon," (updated on Nov. 4, 2015), *available at* <http://www3.epa.gov/climatechange/EPAactivities/economics/scc.html>; U.S. EPA, Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 at 4-7 to 4-17 (August 2015), *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_prop_ria_081815.pdf (describing and using the Social Cost of Methane to calculate the net benefits of a proposed rule, and citing Marten, et al. (2015)).
- ³³ See *id.* In February 2010, the Interagency Working Group (IWG) released estimated Social Cost of Carbon values, developed using the three most widely cited climate economic impact models (known as integrated assessment models). These models were each developed by outside experts, and published and discussed in peer-reviewed literature. An accompanying Technical Support Document released by the IWG discussed the models, their inputs, and the assumptions used in generating the Social Cost of Carbon estimates. The Government Accountability Office recently examined the IWG's process, and found that it was consensus-based, relied on academic literature and modeling, disclosed relevant limitations, and was designed to incorporate new information via public comments and updated research. See U.S. Gov't Accountability Office, REGULATORY IMPACT ANALYSIS: DEVELOPMENT OF SOCIAL COST OF CARBON ESTIMATES (2014).
- ³⁴ Marten, et al., *supra* note 28. Marten et al. takes a reasonable (and conservative) approach to estimating the Social Cost of Methane and currently constitutes the best available science to inform agency regulation. Specifically, Marten et al. builds on the methodology used to develop the Social Cost of Carbon. The study maintains the same three integrated assessment models, five socioeconomic-emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach that were agreed upon by the Interagency Working Group.
- ³⁵ See 80 Fed. Reg. 52,099, 52,145 (Aug. 27, 2015) (Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills); 80 Fed. Reg. 56,593 (Sept. 18, 2015) (Oil and Natural Gas Sector: Emission Standards for New and Modified Sources).
- ³⁶ See 43 C.F.R. §§ 3473.3-2; 3432.2(c).
- ³⁷ See Table 5. We assume an average elasticity of supply of between 1 and 3 (based on EIA's chosen elasticity of supply for U.S. coal (Haggerty et al., 2015)); this results in estimated lost revenue of between \$1.2 billion and \$600 million, from 2009 through 2013. Regional supply elasticity in the Powder River Basin may be more inelastic (lower), making the upper limit on lost revenue about \$1.6 billion.
- ³⁸ See 80 Fed. Reg. 52,099 (Aug. 27, 2015) (Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills); 80 Fed. Reg. 56,593 (Sept. 18, 2015) (Oil and Natural Gas Sector: Emission Standards for New and Modified Sources).
- ³⁹ This value assumes that there is no leakage to non-federal areas in the United States.
- ⁴⁰ For more information on why the Social Cost of Methane is a lower bound estimate of the social cost of methane emis-

sions, see: Institute for Policy Integrity, NYU School of Law, *Joint Comments on Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium and Heavy-Duty Engines and Vehicles; Phase 2* (Oct. 1, 2015), available at http://policy-integrity.org/documents/Oct2015_Joint_Comments_to_EPA-NHTSA.pdf.

⁴¹ This issue is described in more detail in our October 2015 report, *Reconsidering Coal's Fair Market Value*, *supra* note 3 at 21.

⁴² This report focuses on “upstream” externalities produced at the mine site and “midstream” externalities produced by coal transportation, as opposed to “downstream” pollution that occurs at power plants or industrial end users. For an analysis of both upstream and downstream coal externalities and corresponding royalty rate increases, see Alan Krupnick, Joel Darmstadter, Nathan Richardson, and Katrina McLaughlin, PUTTING A CARBON CHARGE ON FEDERAL COAL: LEGAL AND ECONOMIC ISSUES, RESOURCES FOR THE FUTURE (March 2015), available at <http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-DP-15-13.pdf>.

⁴³ See Appendix A (citing U.S. ENERGY INFORMATION ADMINISTRATION, Annual Coal Distribution Report 2013 (2015), available at <http://www.eia.gov/coal/distribution/annual/>).

⁴⁴ See Appendices A and B.

⁴⁵ See 30 C.F.R. § 1206.261(a).

⁴⁶ See Office of Natural Resources Revenue, Proposed Rule, Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, Docket No. ONRR- 2012-0004, 80 Fed. Reg. 608, 609 (Jan. 6, 2015).

⁴⁷ See Mark Haggerty, An Assessment of U.S. Federal Coal Royalties Current Royalty Structure, Effective Royalty Rates, and Reform Options, HEADWATERS ECONOMICS 2-3 (Jan. 2015), available at <http://headwaterseconomics.org/wp-content/uploads/Report-Coal-Royalty-Valuation.pdf>.

⁴⁸ See 43 C.F.R. §§3473.3-2(e), 3485.2(c)(1).

⁴⁹ Haggerty, *supra* note 47 at 8.

⁵⁰ See 30 U.S.C § 207; 43 C.F.R. §§ 3473.3-2; 3432.2(c).

⁵¹ See 43 C.F.R. § 3473.3-2.

⁵² See 30 U.S.C § 207; 43 C.F.R. § 3473.3-2.

⁵³ See 43 C.F.R. §§ 3473.3-2; 3432.2(c)).

⁵⁴ See 5 U.S.C. § 706(2)(A).

⁵⁵ See 43 C.F.R. §§3473.3-2(e), 3485.2(c)(1).

⁵⁶ 5 U.S.C. § 706(2)(A).

⁵⁷ See, e.g., *Bowman Transp., Inc. v. Arkansas-Best Freight Systems, Inc.*, 419 U.S. 281, 290 (1974) (“[W]e can discern in the Commission’s opinion a rational basis for its treatment of the evidence, and the ‘arbitrary and capricious’ test does not require more.”); *Mississippi Valley Barge Co. v. United States*, 292 U.S. 282, 286-87 (1934) (“The judicial function is exhausted when there is found to be a rational basis for the conclusions approved by the administrative body.”); *Ethyl Corp. v. EPA*, 541 F.2d 1, 34 (D.C. Cir. 1976) (stating that the arbitrary and capricious standard of review “requires affirmation if a rational basis exists for the agency’s decision.”), cert. denied, 426 U.S. 941 (1976).

⁵⁸ See *Motor Veh. Mfrs. Ass’n v. State Farm Ins.*, 463 U.S. 29, 43 (1983) (agency decisions are arbitrary if they entirely fail to consider an important aspect of the problem); *California v. Watt* (“Watt I”), 668 F.2d 1290, 1317 (D.C. Cir. 1981) (“When reviewing the policy judgments made by the Secretary [of the Interior], including those predictive and difficult judgmental calls the Secretary is called upon to make, we will subject them to searching scrutiny to ensure that they are neither arbitrary nor irrational—in other words, we must determine whether the decision is based on a consideration of the relevant factors and whether there has been a clear error of judgment)(internal citations omitted). In *Watt I*, the Court found that Interior failed to consider all of the relevant enumerated factors in section 18 of the Outer Continental Shelf Lands Act (OCSLA) when preparing its five-year plan for offshore leasing. 668 F.2d at 1325; see also *California v. Watt* (“Watt II”), 712 F.2d 584, 596 (D.C. Cir. 1983) (holding that the Secretary of the Interior met OCSLA’s requirements and was “free to choose any methodology ‘so long as it is not irrational.’”)(quoting *Watt I*, 668 F.2d at 1313, 1320). Unlike in section 18 of OCSLA, no enumerated factors appear in the federal statutes governing coal royalty rates.

⁵⁹ 30 U.S.C. § 207(a).

⁶⁰ 30 U.S.C. §207(a).

⁶¹ See Krupnick, et al., *supra* note 42 at 15.

⁶² See, e.g., 30 U.S.C. §201(a)(3)(C) (“Prior to issuance of any coal lease, the Secretary shall consider effects which mining of the proposed lease might have on an impacted community or area, including, but not limited to, impacts on the environment, on agricultural and other economic activities, and on public services.”).

- ⁶³ See, e.g., *Boesche v. Udall*, 373 U.S. 472, 476 (1963) (noting that Interior has been vested with “general managerial powers over the public lands”); *N.W. Coal. for Alternatives to Pesticides v. Lyng*, 673 F. Supp. 1019, 1024 (D. Or. 1987) (“So long as the BLM’s decisions are not irrational or contrary to law, it may manage the public lands as it sees fit”) (citing *Natural Resources Defense Council v. Hodel*, 819 F.2d 927, 980 (9th Cir. 1987)); see also *Amoco v. Watson*, 410 F.3d 722 (D.C. Cir. 2005) (upholding BLM’s order to an energy company to pay additional royalties, as “deference is particularly appropriate in the context of a complex and highly technical regulatory program, in which the identification and classification of relevant criteria necessarily require significant expertise and entail the exercise of judgment grounded in policy concerns.”) (internal citations omitted).
- ⁶⁴ See Krupnick, et al., *supra* note 42 at 18.
- ⁶⁵ See *Watt II*, 712 F.2d at 606 (holding that OCSLA Section 18(a)(4)’s requirement that the program assure receipt of fair market value “does not mandate the maximization of revenues, it only requires receipt of a fair return,” and that Interior acted reasonably in adopting evaluation procedures designed to assure the government’s receipt of fair market value).
- ⁶⁶ See generally Georgio Brosio, “Oil Revenue and Fiscal Federalism,” in FISCAL POLICY FORMULATION AND IMPLEMENTATION IN OIL-PRODUCING COUNTRIES (Eds. J. M. Davis, et al.) 243 (Jan. 1, 2003); Helena McLeod, Compensation for Landowners Affected by Mineral Development: The Fijian Experience, RESOURCES POLICY, Vol. 26, Issue 2, pp. 115–125 (June 2000); John Burritt McArthur, *The Mutual Benefit Implied Covenant for Oil and Gas Royalty Owners*, 41 NAT. RESOURCES J. 795, 882 (2001) (“The lessee or its assignee will make all key development decisions, including when to drill, where to drill, and who else will invest in the project. It makes the technical decisions that can so alter the outcome, including decisions with very long-term environmental effects that may only become apparent after operations are long over.... The idea that the lessee cannot feather its nest by soiling the royalty owner’s is a fundamental principle of oil and gas law and, as such, has been acknowledged by a wide array of existing cases.”). And from an economic standpoint, Pareto efficiency demands that for a project to be efficient at least one person must benefit and no person should be made worse off. By compensating those who are negatively affected by the mining development for the costs that they have to bear (such as pollution), Pareto efficiency can, in theory, be achieved.
- ⁶⁷ H.R. REP. 94-681, 38, 1976 U.S.C.C.A.N. 1943, 1975 WL 12515 (Leg.Hist.). The Federal Coal Leasing Amendments Act “will add 12.5 percent of the moneys received under section 35 of the Mineral Lands Leasing Act to the 37.5 percent share currently returned to the states.” The legislative history also reflects concern as to “the waste of valuable resources, and the creation of severe environmental impacts.” *Id.* at 20.
- ⁶⁸ H.R. 15175, 94th Cong., 2d Sess. at 13-14 (August 10, 1976).
- ⁶⁹ Gulf of Mexico Energy Security Act, Pub. Law 109-432 (2006).
- ⁷⁰ See 43 U.S.C. § 1337(g)(5); Section 8(g)10 of the OCSLA amendments of 1985 (P.L. 99-272).
- ⁷¹ See CONGRESSIONAL RESEARCH SERVICE, NO. R40645, U. S. OFFSHORE OIL AND GAS RESOURCES: PROSPECTS AND PROCESSES 19 (April 26, 2010), available at <http://fpc.state.gov/documents/organization/142736.pdf>; see also Senate Hearing 113-122, Revenue Sharing Hearing before the Committee on Energy and Natural Resources, United States Senate, 113th Congress, 1st Session to Consider S. 1273, The Fair Act of 2013 (July 2013), available at <http://www.gpo.gov/fdsys/pkg/CHRG-113shrg85874/html/CHRG-113shrg85874.htm> (stating, inter alia, “Revenue sharing is vital for these [coastal] areas to adequately respond to all sorts of impacts associated with enormous influxes of people and equipment;” “States and communities will have less incentive to support this development if they’re expected to shoulder risks and absorb impacts with no opportunity for revenue sharing” “[t]here are also cumulative impacts of offshore energy development such as habitat degradation and coastal erosion that are typically not mitigated at the project level, and it is important for states to address these impacts. Therefore, a significant portion of a state’s revenue share should be directed to addressing those unmitigated cumulative impacts, including through coastal protection and restoration and investments in natural infrastructure such as forested wetlands, marshes, oyster reefs, barrier islands, and dune systems.”).
- ⁷² *Id.*
- ⁷³ See 30 C.F.R. § 219.410(d)(1)(A)-(C).
- ⁷⁴ See *id.*
- ⁷⁵ In October 2015, Congress failed to reauthorize the Land and Water Conservation Fund. As a result, absent future reauthorization, it will no longer be funded by federal fossil fuel royalties. See Jodi Peterson, “Congress Lets Sun Set

on Land and Water Conservation Fund,” HIGH COUNTRY NEWS (Oct. 1, 2015), available at <http://www.hcn.org/articles/congress-lets-sun-set-on-land-and-water-conservation-fund>.

⁷⁶ See 43 U.S.C. § 1701(a)(9).

⁷⁷ *Ctr. for Biological Diversity v. Nat’l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1197-98, 1203 (9th Cir. 2008).

⁷⁸ See Part II, *infra*.

⁷⁹ See U.S. Bureau of Ocean Energy Management, Gulf of Mexico Lease Terms and Royalty Relief (updated Nov. 5, 2012), available at http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics/Fair_Market_Value/GOMLeaseTermsRRSummary.pdf.

⁸⁰ See Hon. Ken Salazar, Secretary of the Interior, “Interior, Environment, and Related Agencies Appropriations for 2013,” Testimony before the House Committee on Appropriations, Subcommittee on Interior, Environment, and Related Agencies (Feb. 16, 2012), pp. 46–47, available at <http://www.gpo.gov/fdsys/pkg/CHRG-112hrg74739/pdf/CHRG-112hrg74739.pdf> (“The President’s budget includes an estimated royalty rate which is at 18.75 percent for the onshore. The underlying principle is we are mandated by statute, mandated by fairness to make sure the American taxpayer is getting a fair return for the assets the American people own.”).

⁸¹ See 43 U.S.C. § 1701(a)(12).

⁸² See 30 U.S.C. § 201(a)(1) (“The Secretary of the Interior... shall, in his discretion, upon the request of any qualified applicant or on his own motion, from time to time, offer such lands for leasing and shall award leases thereon by competitive bidding.”); see also *United States ex Rel. McLennan v. Wilbur*, 283 U.S. 414, 419 (1931) (holding that the Secretary of the Interior, under the Mineral Leasing Act of 1920, had discretion to grant or deny a prospecting permit for oil and gas).

⁸³ See *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984).

⁸⁴ See Krupnick, et al., *supra* note 42 at 19; see also *Boesche v. Udall*, 373 U.S. 472, 476 (1963) (noting that Interior has been vested with “general managerial powers over the public lands”); *N.W. Coal. for Alternatives to Pesticides v. Lyng*, 673 F. Supp. 1019, 1024 (D. Or. 1987) (“So long as the BLM’s decisions are not irrational or contrary to law, it may manage the public lands as it sees fit”) (citing *Natural Resources*

Defense Council v. Hodel, 819 F.2d 927,980 (9th Cir. 1987)).

⁸⁵ U.S. GOV’T ACCOUNTABILITY OFFICE, COAL LEASING REPORT, *supra* note 20 at 16.

⁸⁶ *Id.* at 28.

⁸⁷ The minimum bid of \$100 per acre, or the equivalent in cents per ton, was set by regulation in 1982. See 43 C.F.R. § 3422.1(c)(2). The rental rate of \$3 per acre was set in 1979. See *id.*, § 3473.3-1 (a).

⁸⁸ According to the Bureau of Labor Statistics, \$100 in 1982 has the same buying power as \$247 in 2015 dollars. BUREAU OF LABOR STATISTICS, CPI Inflation Calculator, available at http://www.bls.gov/data/inflation_calculator.htm.

⁸⁹ See 30 U.S.C. § 1259 (“The amount of the bond shall be sufficient to assure the completion of the reclamation plan if the work had to be performed by the regulatory authority in the event of forfeiture and in no case shall the bond for the entire area under one permit be less than \$10,000.”).

⁹⁰ See Appendix A at 2-3 (citing Epstein et al., 2011).

⁹¹ Accounting for these fixed costs when selling the coal tract assumes that the next-best use of the tract has zero externalities; this is a reasonable assumption for many western tracts that would otherwise be used for scenic or recreational purposes.

⁹² See Hein, RECONSIDERING COAL’S FAIR MARKET VALUE, *supra* note 3 at 5-6.

⁹³ See U.S. Bureau of Ocean and Energy Management, 2017-2022 Draft Proposed Program, at 5-20, 8-1 to 8-19.

⁹⁴ *Center for Sustainable Economy v. Jewell*, 779 F.3d 588, 610 (D.C. Cir. Mar. 6, 2015). Policy Integrity served as counsel to Petitioner, Center for Sustainable Economy. See also Opening and Reply Briefs for Petitioner.

⁹⁵ See 43 C.F.R. § 3400.5.

Economic Appendices

Appendix A

Externalities of Coal Mining

According to existing statutes, the Department of the Interior (“Interior”) must obtain at least fair market value for the development of fossil fuels—including coal—on public lands. If we interpret “fair market value” narrowly, we can interpret this as the market price of all fossil resources—coal and natural gas—on the land, and their corresponding option value. If we interpret “fair market value” more broadly, we can interpret this as maximizing the social return of mining; this includes the fair market price of fossil fuel resources—e.g., coal and natural gas—and the social cost of mining—i.e., the cost to American consumers of mining on public lands due to non-internalized externalities, and their corresponding option values. According to both definitions of fair market value, the Department of Interior should increase the price of coal leases—via minimum bids and royalty rates.

This section—Appendix A—discusses the various externalities from coal production, upstream of coal fired power plants. We focus on upstream externalities because they: (1) directly stem from the mining of coal and not the final use of coal, and (2) are not internalized by existing power plant regulations. Specifically, this Appendix discusses the upstream externalities from producing a “typical” ton of coal mined on public lands in the United States. While the externalities from any particular mine vary according to its location (i.e., the human population and the environmental sensitivity of the surrounding landscape), the chemical makeup of the soil and coal, and mining and transportation methods employed in production (Berry et al., 1995; Freeman and Rowe, 1995; Krupnick and Burtraw, 1996; Dones et al., 2005; Odeh and Cockerill, 2008; Burtraw et al., 2012), it is valuable for policymakers setting minimum bids and royalty rates to know the average externality burden of mining on U.S. public lands to ensure that they are capturing the fair market value for coal production. However, to do so, we first need to define a “typical” coal mine.

Boundaries of the Analysis—Defining the Relevant Externalities from a Typical U.S. Coal Mine

This section catalogs the upstream externalities directly related to mining the average ton of coal on U.S. public lands. This includes the relevant externalities from coal production activities—including obtaining mining rights, mining, processing, and transportation (costs that are “upstream” from coal combustion)—and land recovery (if funded by government) for the average ton of coal. None of these costs are internalized by regulations at the power plant level. Given that between 80% to 90% of public coal mining is in the Powder River Basin (“PRB”) of Montana or Wyoming (CRS, 2013, Headwater, 2015), we can define the upstream externalities of a typical ton of coal (from U.S. public lands) as those from the average ton of coal from the Powder River Basin. Coal from the PRB is typically strip mined (a type of surface mining) sub-bituminous coal that is unprocessed and shipped long distances by train for domestic use in power plants (NRC, 2010).

Given the rural nature of this region and long shipping distance, we focus the majority of our attention on the most significant externalities: location-independent production externalities—greenhouse gas emissions, water use, and ecosystem losses—and transportation costs. Additionally, we will briefly discuss various location-dependent externalities—such as non-greenhouse gas emissions into air and water. Finally, this section will conclude with a short discussion of externalities from mining using other methods—underground mining and mountaintop removal (MTR)—and in other regions. We will catalog all relevant externalities across space and time. Given that a significant externality from strip mining is

methane leakages that impact the entire planet, we determine that the relevant spatial range of externalities is global. For non-GHG impacts, the spatial ranges of relevant and significant impacts are local or domestic in nature. Additionally, all externalities that occur from mining during the lifetime of the mine are included. This includes costs after the closing of the mine—e.g., cleanup costs, site rehabilitation, and climate change impacts—that result directly from coal mining (Berry et al., 1998).

We ignore “externalities” that are already internalized into mine operators’ decisions. For example, several life cycle analyses of coal quantify and value occupational hazards (e.g., Lee et al., 1995)¹. For the purposes of this section, it is not appropriate in this context because it is generally assumed that these costs are internalized through higher wages, insurance premiums, etc. (NRC, 2010). As a consequence, the company already internalizes these costs—and hence—they are not truly externalities.

Average Externalities from a Metric Ton of U.S. Coal

Externalities from producing coal occur at the various stages of the coal production process: the obtaining of mining rights, mining, processing, and transportation. In other words, each of these stages of coal production results in costs borne by the public, and not the coal company producing these externalities. In this subsection where we characterize the average externalities of a metric ton of coal produced on public lands in the United States, we ignore externalities at the processing stage because coal from the PRB is raw: it is crushed and resized to lower transport costs but not washed to remove impurities (UCS, 1999; NRC, 2010).

Obtaining Mining Rights. The external cost of obtaining the mining rights of a tract include lost amenities to the public from their exclusion to the tract and any unfunded land reclamation.

The public loses access to property when a coal company obtains mining rights to that property through the bidding process. In particular, the surrounding community loses recreational services and other (though not necessarily all) amenities provided by a particular tract (Epstein, 2011). Additionally, the eventual conversion of the site from natural landscape to a working landscape can potentially imply a further loss of amenities (Power, 2005). Given that the creation of a surface mine entails the removal of vegetation and soil (UCS, 2015), the loss of recreational and other amenities from the conversion of the site to a working landscape may be semi-permanent, at least until the mining site is returned to its prior condition as required by the 1977 Surface Mining Control and Reclamation Act (Epstein et al., 2011; NRC, 2010). However, given that the reclamation of many mining sites goes unfunded by the Abandoned Mine Reclamation Fund set up for this purpose (Epstein et al., 2011; UCS, 2015), these losses may be permanent (Epstein et al., 2011).²

As mentioned above, reclamation of surface mines is required by U.S. law. Reclamation can take the form of returning the land to “agricultural use, rangeland, tree groves, or recreation (Spath et al., 1999).” Given the underfunding of reclamation—as discussed in the previous paragraph—the government may have to pay for this reclamation (an additional externality of the mining) to reverse this loss (Epstein et al., 2011).³

Given the low density of Wyoming region, the recreational amenities of these sites are likely to be low. The exceptions are if the site provides significant tourism or ecosystem benefits, particularly for valuable species. In the latter case, the site may have significant existence values for non-residence if the ecosystem supports rare and desired species. Otherwise, these values are likely to be less significant. Mining locations in more population-dense regions and ecologically significant regions—such as the Appalachians—may face higher externality costs from the obtaining of mining rights (Epstein et al., 2011).

The externalities associated with the obtaining of mining rights are the sole fixed social costs of mining. These are the sole externalities that should be captured in the minimum bid price, instead of royalty prices. Though as appendix D discusses, the option value associated with the uncertainty of fossil resource (coal and natural gas) prices and environmental externalities should also increase the minimum bid for coal tracts.⁴

Production. Coal mining produces several production-related externalities, including the emissions of greenhouse gases, water pollution, and potentially inefficient water use. As noted earlier, onsite working hazards are not an externality, and are internalized into the costs by firms. Each of these production externalities is a variable social cost of coal production, and should be included as an addition to the royalty rate.

The emission of greenhouse gases—though small relative to emissions from combustion (NRC, 2010; Odeh and Cockerill, 2008)—is likely the most significant externality from coal mines (Berry et al., 1995; Berry et al., 1998, Krupnick and Burtraw, 1996).⁵ The most important source is methane emissions from mining—also known as methane leakage—which occurs when gases trapped in coal seams are released when they are cut to extract coal (NRC, 2010). Though methane emissions remain in the atmosphere for a shorter time than carbon dioxide (EPA, 2015b), methane emissions are a serious concern because methane has a global warming potential 84 times that of carbon dioxide in 20 years after emission and 34 times in 100 years after emissions. In 2009, EIA (2011) estimated that coal mining released 86 million metric tons CO₂e of methane (measured in CO₂ equivalents using a global-warming potential of 25).⁶ Given that the United States produced 975 million metric tons of coal in 2009 (EIA, 2011), the U.S. emission rate was 0.09 metric tons of CO₂e per metric ton of coal.⁷ In addition to these emissions from mining, there are also emissions from abandoned surface mines which EPA (2015) estimated at 2.5 million metric tons in 2009.⁸ Underground mining releases more methane emissions than surface mining (as does abandoned underground mines relative to underground surface mines (EPA, 2015)) because the coal beds are under more pressure, due to their deeper depths (Spath et al., 1999); though some methane is captured in underground mining (Spath et al., 1999; EPA, 2015).⁹

Alternative production sources of greenhouse gas (GHG) emissions include mining equipment—potentially including trucks used to move coal on site—that mostly rely on fossil fuels (NRC, 2010). Additionally, coal mining uses substantial levels of electricity (Spath et al., 1999). While emissions from equipment are significant for surface mining, they are more significant for underground mining that relies on small, less energy efficient equipment as compared to the large and more energy efficient equipment used in strip mining (NRC, 2010, UCS, 2015). According to Spath et al., (1999, page 29), CO₂ emissions (excluding methane) from surface mining accounts for 0.9% of CO₂ emissions in the lifecycle of U.S. coal.^{10,11}

Running equipment (drills, bulldozers and trucks) causes additional types of air pollution other than GHG emissions—particularly criteria pollutants (NRC, 2010). Again, relative to air pollution from power plants, the impacts of mine are small (Berry et al., 1995; Berry et al., 1998; Spath et al., 1999 Table B2). Coal operations also create noise pollution as they operate (Bickel et al., 2005; NRC, 2010). Given the low populations of Wyoming and Montana, these externalities are likely to be less significant.¹²

Coal mining emissions also negatively affect water resources, and thus human health, livestock, fishing stocks, and aquatic species (Berry et al., 1995; Lee et al., 1995; Berry et al., 1998; Nkambule and Bignaut, 2012). Water quality effects are extremely site specific—depending on the soil chemistry, site's geology and the mining methods.¹³ Given that water quality impacts continue after mining efforts end, impacts also partially depend on whether and what reclamation efforts are made. Water quality impacts tend to be most severe near the mine, they often dissipate as the waste moves farther and

farther downstream. As a consequence, the severity of impacts also depends on whether and where households, prime farmland, scenic sites, and critical and sensitive ecosystems are located along the impacted waterway (Lee et al., 1995; Epstein et al., 2011). Even so, coal mining is a significant source of water pollution in the life-cycle of coal (Spath et al., 1999).¹⁴ Even small amounts of water pollution from coal mine waste can pose problems for ground water (Berry et al., 1995).

Acid mine runoff (also known as drainage)—the creation of sulfuric acid through a chemical reaction when water runs across exposed rocks containing sulfur—is the most common and severe water pollutant from coal surface mines (Epstein et al., 2011).¹⁵ Acid mine drainage negatively affects aquatic ecosystems and can negatively affect buildings and infrastructure (Lee et al., 1995). In the Western United States, acidity is less of a problem due to the alkaline nature of the soil and water (USGS, 1999). Instead, alkaline mine drainage from “turbidity, sedimentation, and osmotic stress from high dissolved solids concentrations” on “inadequately controlled western coal fields” is more of an issue for U.S. public coal mines (Lee et al., 1995); this type of pollution also negatively effects on ecosystems. Additionally, increased solid loading from mining-induced erosion can also decreased aquatic habitat (Lee et al. 1995). In particular, strip mining can affect aquatic habitats through increased storm runoff and sedimentation (Lee et al. 1995).¹⁶

In addition to polluting water, coal mining also uses a significant amount of water for dust control, extraction (i.e., to cool equipment and prevent fire), and processing (e.g., coal washing) (Nkambule and Blignaut, 2012; Peabody, 2012). The Department of Energy (2006) estimates that U.S. coal mining uses approximately 70 to 260 million gallons per day, with average uses of 10 gallons per ton of coal mined on the surface in the West and 100 gallons per ton of coal mined underground in Appalachia. In addition, 80% of Eastern coal is washed, using an additional 20 to 40 gallons per ton. Valuing water at its opportunity cost, Nkambule and Blignaut (2012) find that the external cost of water consumption from coal mining and transportation for a future planned South African mine was the highest external cost, exceeding the costs of global warming by 16 fold. To the extent that Wyoming and Montana does not have an efficient water market and faces water shortages in the relevant watersheds, this may also be an externality cost faced by Western coal regions.¹⁷ Given that water law makes changing water uses very difficult in Wyoming (Duke, 2013), the opportunity cost of mining water in the PRB is likely positive—especially during water shortages. When considering the twelve Western United States—including Montana and Wyoming—as a whole market, the regional opportunity cost of water used in coal mining likely exceeds the local price of water (Libecap, 2010; Grafton et al., 2011).

Transportation. The transportation of coal requires large amounts of energy and includes some risks. In the United States, coal companies transport 70% of their product by rail, approximately 10% by truck, 10% or more by waterways, and the rest using a variety of means including conveyor belts and slurry pipelines.¹⁸ Domestically, coal accounts for almost half of all tonnage, a quarter of all carloads, and over 40% of commercial freight sent by rail (NRC, 2010). Reliance on rail is even higher in Wyoming—where the majority of the PRB is located—because of its rural nature and due to its large export share; 90% of coal is shipped out of state for use in power plants, with almost 4% going all the way to the East Coast (Florida, George, and New York) (EIA, 2015).¹⁹ While 96% of Wyoming coal shipped by rail in 2013, alternative transportation methods (truck, waterways, and pipeline) are mainly used for shipping coal for within state use (55%) (EIA, 2015). Transportation by rail results in multiple externalities: increased risk to public health through accidents and air pollution, emission of greenhouse gases, and disamenities such as noise. Each of these transportation externalities is a variable social cost of coal production, and should be included as an addition to the royalty rate.

Increased rail transportation from coal results in an increase in rail-related accidents. As a consequence, there is an increase in workforce and public mortality and morbidity due to rail accidents. Like mining accidents, deaths and injuries

from workplace accidents are not externalities because they are internalized into company decisions through higher wages and insurance rates. To the extent that companies do not fully internalize the social cost of public fatalities and injuries from rail transport, these costs are externalities—potentially a significant one (Krupnick and Burtraw, 1996, p. 437). In 2008, there were “571 freight rail fatalities and 4,867 [freight rail] nonfatal injuries” where 97% of fatalities were non-employees and most injuries were to employees; NRC (2010) estimates that 265 and 767 members of the public were killed or injured, respectively, by freight trains in the United States (NRC., 2010).²⁰ Some portion of these costs will be internalized through expected lawsuits—though approximately 4.7% according to Lee et al (1995).²¹

Trains run on fossil fuels—in particular diesel—which produces a variety of air pollutants, including nitrogen oxide (i.e., an ozone forming gas), soot (i.e., a particulate matter), sulfur dioxide²², carcinogens, and CO₂ (Epstein et al., 2011; UCS, 2015; Odeh and Cockerill, 2011; NRC, 2010). The emissions of non-greenhouse gas emissions have human health and environmental consequences.²³ In 2006, U.S. diesel trains released approximately one million tons of ozone forming oxides of nitrogen (7.2% of transportation sector emission) and 32,000 tons of PM_{2.5} (5.6% of transportation emissions) causing 3,400 deaths and 290,000 lost work days (EDF, 2006). Sulfur dioxide and nitrogen oxide emissions from coal mining and transport also decrease visibility by forming haze; pollution from these activities in the PRB is known to have decreased visibility in Badlands National Park (EDF, 2006). Additionally, transportation of coal accounts for 1.7% of CO₂ emissions in the life cycle of coal production according to Spath et al (1999).²⁴ In general, trains are a minor cause of air pollution—GHG and non-GHG—relative to mines and power plants (Spath et al., 1999, Table B2). However, the amount and impact of this pollution depend on the transportation distance, the method of transportation (truck, train, barge, and pipeline), and the characteristic of these transportation methods (e.g., weight of train) (Odeh and Cockerill; Spath et al., 1999). Given the importance of distance in determining the air quality impacts of coal transportation, the impacts of transportation are likely to be higher for long-distance hauling of coal from the PRB relative to the national average (Spath et al., 1999).

Increased train traffic also produced negative amenities: noise and congestion. In addition to being a disamenity—i.e., noise from trains annoys nearby residents—there are negative health impacts from noise: heart disease, hypertension, and poor sleep. There are several statistical studies demonstrating that households have a relatively high willingness to pay to not live near train tracks. Specifically, households are willing to pay less for houses in close proximity to train tracks (Bickel et al., 2005, p. 160). In addition to noise, train traffic from coal transportation by rail can potentially increase and delay traffic: number of cars at crossings and time spend at crossings (Radwan and Alexander, 1983; Berry et al., 1995; Seattle, 2012). These disamenities are potentially costly.

Additional Costs

As stated earlier, the upstream costs of coal mining are site and production method specific. In addition to strip mining, coal mining takes the form of underground mining and mountaintop removal. The U.S. produces coal in many states other than Wyoming;²⁵ production in these states is often on private land and sometimes uses these alternative methods.²⁶ Given that strip mining in Wyoming still makes up the vast majority of public coal in the United States, these alternative methods and regions make up a minor share of public coal mines. Even though stripping mining in the PRB reflects the average cost of coal mining on public lands, BLM should estimate the additional costs of alternative mining methods (underground mining and mountaintop removal) and production in other regions in order to adjust this average cost estimate to reflect higher cost situations.²⁷

Underground Mining. Overall, surface and underground mining have the same level of emissions. The main difference is that surface mining produces more ammonia emissions²⁸ due to the use of blasting, while underground mining produces more particulate emissions due to the use of limestone (Spath et al., 1999). As mentioned earlier, underground mines produce more methane per unit of production, from twice as much (Spath et al., 1999, p. iv) to six times as much (Spath et al., 1999, Table 52)—though some is captured for use. Additionally, underground mines can result in subsidence—the sudden or gradual collapse of a mine—which can affect water flows and damage housing and infrastructure (Berry et al., 1995; NRC, 2010). Abandoned mines can also suffer from subsidence, as well as mine fires and leakage of mine waste into waterways (NRC, 2010). While Spath et al. (1999) indicates that there is general equality of damages between the two types of mines, the evidence appears to favor strip mines as less damaging to human and environmental health on a per tonnage basis.

A higher percentage of underground mines are found in the Eastern United States. As a consequence, there is high correlation between impacts of underground mining and externalities from being located in a different location—i.e., East of the Mississippi—where coal mining externalities are higher due to differences in the chemical structure of the soil and coal: including acid mine drainage and water pollution from the processing of coal. See below for more.

Mountaintop Removal (MTR). Of the various types of coal mining methods used in the United States, mountaintop removal—a type of surface mine most commonly used in Appalachia—produces the most externalities (NRC, 2010; UCS, 2015). In addition to sharing many of the externalities common to other types of surface mining, such as strip mining, MTR produces many additional externalities due to the steep terrain where it is used and the production of excess spoils—large volumes of coal mining waste—which are often disposed in the valley below. This excess waste can pollute waterways—with carcinogens and heavy metals—and can even completely cover them with debris; approximately 2,000 miles of rivers—including headwaters—have been buried in Kentucky, Virginia, West Virginia, and Tennessee. The mining also affects land based ecosystems by removing trees, completely transforming huge swaths of landscape (1.4 million acres in Kentucky, Virginia, West Virginia, and Tennessee), fragmenting the landscape, and compacting the soil (NRC, 2010; Epstein et al., 2011); the practice deteriorates soil quality in the surrounding area so much that forested ecosystems are replaced by exotic grasses—the only ecosystem that the soil can support. As a consequence, the practice increases the risk of flooding and landslides, increasing damages to housing, infrastructure, and waterways (NRC, 2010; Epstein et al. 2011, UCS, 2015).

Greenhouse gas emissions are even higher for MTR. In addition to methane leakage, there is the loss of CO₂ stored in the soil and emissions from spoils. Citing the Fox and Campbell (2009) study of the effects of mountaintop removal on the lifecycle, Epstein et al (2011) argues that the use of mountaintop removal increases CO₂ emissions in the lifecycle of coal by 17% due to deforestation and land change. As a consequence, indirect emissions from MTR are equivalent to 7% of emissions from conventional coal powered power plants—approximately 6 to 7 million tons of CO₂ stored in forests, 2.6 million tons of CO₂e stored in soil, and 27.5 million CO₂e emitted from mining spoils are lost annually (Epstein et al, 2011).²⁹ For southern Appalachian forests, this implies up 30 million tons of CO₂ emissions annually. In addition to greenhouse gas emissions, non-GHG emissions may also increase as the result of MTR (Epstein et al., 2011).

Again, mountaintop removal is predominately used in the Eastern United States. Therefore, like underground mines, the types of externalities are strongly correlated with externalities common to mining Eastern coal. See below for more.

Other Locations. Mining coal in the Eastern United States implies additional externalities—this is partly due to the different soil and coal composition. As discussed earlier, acid mine drainage is a more significant in the Eastern United States, instead of alkaline mine drainage. Additionally, coal in the Eastern United States must be processed—specifically

washed with water and chemicals—before shipping to power plants (NRC, 2010). The waste from the processing—which consists of up to 50% of the processing inputs according to NRC (2010)—is known as slurries, and contains toxic chemicals and heavy metals. Due to its toxic nature—to humans and ecosystems—it is stored in impoundments. In the United States, this waste is a significant contributor to water contamination. Particularly costly are large scale pollution events that can occur when these impoundments give way due to their unstable location or extreme weather events (NRC, 2010; Epstein et al., 2011).³⁰

Location of upstream coal mining externalities also matter because the Eastern United States—such as West Virginia, Kentucky, and Pennsylvania—is more densely populated than Wyoming—one of the least densely populated states. As a consequence, non-greenhouse gases and water pollution affect greater numbers of people. This is because more individuals are exposed to toxins—increasing health impacts—and more people experience a loss of nearby environmental amenities. For similar reasons, the cost of noise pollution, loss of recreational sites due to mining, and congestion all result in higher external costs in more dense locations (Freeman and Row, 1995). Additionally, much of mountaintop removal is in Appalachia—a biological hotspot—where coal mining costs in terms of ecosystem services and biodiversity are high (Epstein et al., 2011).³¹

Finally, Eastern mines potentially ship their coal shorter distances and less by rail.³² Shorter distances imply fewer externalities from the transportation of coal. However, this lower externality pressure is somewhat offset by Eastern mines higher reliance on freight trucks than the Western United States. Compared to freight trains, freight trucks produce higher levels of externalities per ton-mile as trains (Forkenbrok, 2001; Austin, 2015; GAO, 2011)—fatalities, air pollution, noise, congestion costs, and wear and tear of public roads (Berry et al., 1995; Lee et al., 1995; Krupnick and Burtraw, 1996).³³ Overall, the total externality costs for truckers are between 2 to 9 times higher than trains on a mile-ton basis. This implies higher costs per ton-mile for coal in the rest of the United States versus the PRB—between 7% and 80% higher (Gorman, 2008; Forkenbrok, 2001; Austin, 2015; GAO, 2011).

Appendix B

How Interior Should Value Externalities, Accounting for Uncertainties

This section attempts to review the empirical literature on coal mine externalities. In doing so, we highlight estimates of the various externalities discussed in Appendix A. The primary goal is to determine which externalities are the most empirically relevant. Additionally, we discuss how to estimate the relevant externalities. We then assemble the relevant social cost estimates in order to provide lower bound adjustments for the fair market calculation of minimum bid and royalty rates.

An important point to note is that each study determines the relevant scope of their study—just as Appendix A defined the relevant scope for the adjustment of U.S. minimum bids and royalty rates as strip mining in the Powder River Basin (PRB). In doing so, each study defines: (1) the relevant stages of the coal fuel chain to study, (2) the location of coal activities, (3) the relevant technologies, (4) the significant externalities,³⁴ (5) the spatial and temporal limits of these externalities, and (6) how to price these externalities (Berry et al., 1998). Given that many studies chose different scopes than our study, some of the resulting estimates are not compatible with our analysis or require some adjustment. While most studies focus on the lifecycle of coal—i.e., upstream and downstream externalities—we focus exclusively on upstream externalities. More problematic is that none of the studies focus on strip mining on public lands in the Western United States, and are at best studies of the average externalities for U.S. coal mining or an average U.S. power plant. In many cases, studies are empirical estimates from other nations—which are not empirically relevant. When possible, we attempt to adjust domestic estimates such that they reflect the external cost of production of strip mining coal in the PRB.

Literature

In the 1990s, a literature developed to estimate the external cost of energy production and generation for use by utilities and their regulatory commissioners (Burtraw et al., 2012). There are a handful of studies on the external costs of coal from a lifecycle perspective—including both the upstream and downstream social costs of coal production. Burtraw and Krupnick (2012)—a report from Resources for the Future—and Grausz (2012)—a report by the World Bank—highlight and recommend several reports (and their underlying models): RFF/ORNL (Lee et al., 1995),³⁵ the EXMOD computer model used in Rowe et al (1995),³⁶ the 1995 and 2005 versions of ExternE (EC, 1995; Bickel and Friedrich, 2005) and its various applications (Berry et al., 1995; Berry et al., 1998; Dones et al., 2005; Rafaj and Kypreos, 2007),³⁷ and the National Research Council (2010).³⁸ Additionally, the World Bank also highlights Epstein et al. (2011).³⁹ In addition to these reports, Spath et al (1999),⁴⁰ Hondo (2005), Odeh and Cockerill (2008),⁴¹ and Nkambule and Blignaut (2012)⁴² independently estimate the external costs of coal mining or the lifecycle of coal for the United States, Japan, the UK, and South Africa, respectively. For the most part, the above studies apply the damage function approach⁴³—in which they employ the benefit transfer method instead of developing their own primary estimates of parameters to estimate site-specific impacts.⁴⁴

These studies derive a variety of external cost estimates. While these estimates differ, it is likely due to differing locations (including population density) and differing modeling assumptions. The key modeling assumptions for the external cost

estimates are the: treatment of climate change, atmospheric modeling, and differing health and environmental endpoints (Krupnick and Burtraw, 1996; Burtraw et al., 2012). Given these differences, Krupnick and Burtraw (1996) conclude that the external cost estimates are consistent, robust, and meaningful (Krupnick and Burtraw, 1996; Burtraw et al., 2012). Even so, the final estimates should be interpreted as lower bounds because they underestimate the external cost of coal by omitting various impacts (Burtraw et al., 2012)

This section focuses on external costs estimates for domestic upstream coal production, particularly for strip mining. Of the World Bank and RFF recommended models, all of them represent external cost estimates for coal production within the United States, except ExternE. Though not specifically recommended, Spath et al (1999) also estimates the impacts of domestic coal production, though not monetarily. As mentioned earlier, most of these studies are lifecycle analyses. As a consequence, the above studies tend to focus on air pollution from coal combustion because it is the most significant impact in the lifecycle of coal. Given that we are only interested in the upstream costs of coal production, we will only focus on the portion of estimated costs attributed to upstream activities—obtaining mining rights, mining, processing, and transportation—in addition to the public cost of land reclamation. We will discuss foreign estimates or life cycle estimates to the extent that they include currently excluded costs from domestic studies, though we will emphasize the magnitude of the impact and not its particular value. Particular emphasis will be placed on Epstein et al (2011)—a study recommended by the World Bank—because it is up-to-date, published in a peer-reviewed journal,⁴⁵ and estimates the monetary impacts of US coal externalities.

The literature will be augmented by a related literature (which we will call the “transportation literature”) that focuses on valuing the externalities of freight transportation modes: trucks, rail, and waterways. This literature aims to set efficient transportation taxes and fees to internalize the external costs of the transportation of goods. Forkenbrock (1999, 2001) represents an early example of this literature as it applies to U.S. freight trucks and trains. More recently, the GAO (2011) provides partial estimates of freight trucks and trains costs with respect to the costs of accidents and air pollution, and provides a summary of previous estimates of these and other transportation externalities (in Appendix IV) based on a recent review of this literature (Delucchi and McCubbin, 2010). Finally, a 2015 Congressional Budget Office Working Paper (Austin, 2015) adjusts the GAO (2011) estimates the external cost of air pollution from transporting U.S. freight to reflect relatively more up-to-date research (Matthews et al., 2001).

Obtaining Mining Rights—the External Fixed Cost of Coal Mining

In Appendix A, we identified two impacts from a coal company obtaining mining rights: the loss of amenities and the cost of reclamation.

Amenities. While all of the studies consider recreation, we were unable to identify a relevant quantification of the amenities from an unused coal tract.⁴⁶ As argued in Appendix A, the population density of Wyoming is low, which implies that the recreational amenities and ecosystem services of a particular tract of land to the surrounding residents is likely relatively low compared to other externalities. However, there is hunting (e.g., mule deer and sage grouse), fishing and other forms of outdoor recreation in the PRB that benefit non-residents and residents through tourism—making larger amenities possible. Thus, to the extent that these services are disrupted by the auctioning and development of the coal tract, these externalities should be accounted for in the minimum bid, as well as BLM’s internal fair market value calculations. Given the relative size of an individual tract, the effect of developing a particular tract on amenities is likely to be low unless the tract has unique recreation and ecological services (e.g., it has a lake nearby or is home to a breeding ground). Given the highly location specific nature of recreational and ecological amenities, ideally the total value of ame-

nities from the coal tract would be quantified in a site specific study (probably using benefit-transfer methods to save money and time).

There are noise and visual externalities associated with the development and operation of the mine. While Berry et al (1998)—a study estimating the external cost of theoretical power plants in England using ExternE—estimates the cost of noise for both power station and transport, no similar estimate is provided for the mine. Given that Berry et al. (1998) argues that these cost are relatively small and the noise dispersion model tends to over-estimate impacts, noise from establishing and running the coal mine is unlikely to be a major source of upstream externality costs of coal mining, particularly in the low density area of Wyoming.

Reclamation. As noted in Appendix A, reclamation of surface mines is required by law, though many go unfunded. Epstein et al (2011) estimates the cost of unfunded reclamation projects from surface mines as of 2007. Using “data on the number and monetary value of unfunded abandoned mine land projects remaining at the end of 2007 for the nation were collected directly from the Abandoned Mine Land Inventory System”, they estimate a total cost of \$8.8 billion in 2008 USD. Assuming that all of these unfunded reclamations were for mines abandoned after 1977 and that these reclamations will not be funded by the mining companies in the future, this is equivalent to \$0.44/ton in 2015 USD (averaged using all coal production from 1978 to 2007); given the conditional nature of this estimate, this number should be interpreted as an upper bound. A similar analysis should be conducted for Wyoming (or at a minimum the Western United States) for unfunded reclamation projects from 1978 to the current time period.

Production Externalities—External Variable Cost of Coal Mining

In Appendix A, we identified several impacts from the production of coal: greenhouse gas emissions from methane leakage, other air pollution, water use, and water pollution.

Greenhouse gases. Many of the earlier studies do not monetize the costs of greenhouse gas emissions from coal production (Burtraw et al., 2012; Krupnick and Burtraw, 1996). This is true of all of the studies recommended by Burtraw et al. (2012)—with the exception of ExternE (Burtraw and Krupnick, 2012).⁴⁷ At the time of their development, many of the studies decided that that estimates were too uncertain even though they recognized that climate damages represented the most significant cost of coal (Krupnick and Burtraw, 1996); this is unsurprising given that the first social cost of carbon (SCC) estimates were being released during the same time period (Tol, 2011). As the SCC has improved over the last two decades, more recent studies include estimates of climate damages from coal. For example, Epstein et al (2011)—a model recommended by the World Bank—accounts for the costs of GHG emissions—including methane emissions from mines and combustion at plants—as does Nkambule and Blignaut (2012). In all cases, the studies fail to use the appropriate US estimate of the external cost of CO₂ and methane emission—the social cost estimates consistent with the 2013 Interagency Working Group on the Social Cost of Carbon (IWG, 2013; Marten et al., 2015).

Epstein et al (2011) estimates the social cost of greenhouse gas emissions from methane emissions from US mines. Citing the Energy Information Administration (2010), U.S. methane emission from coal were approximately 71 million metric tons of CO₂ equivalent (CO₂e); these estimates use a 25 global warming potential (GWP) to adjust tons of methane to CO₂e. They value greenhouse gas emissions using social cost of carbon numbers of \$10, \$30, and \$100 per metric ton of CO₂—which correspond to ballpark estimates from DICE, FUND, and PAGE using discount rates of 4.5%, 3%, and 1.5%, respectively—drawn from Table 5-9 of NRC (2010). The total cost of methane emissions from U.S. mines equals \$2.2052 billion—with a range of \$0.684 billion to \$6.841 billion—in \$2008. These estimates are also

adjusted downwards by 10% to account for only 90% of coal being used for electricity. Using the EIA estimates of total coal production and correcting for the 10% adjustment downwards, the external cost of methane is \$2.92/metric ton in \$2015—with a range of \$0.89 and \$8.52. However, the Epstein (2011) estimates use outdated GWP warming potential adjustments from the IPCC, unofficial SCC estimates—both of which are too low for the central estimate, and do not differentiate by mining type (methane emissions from underground mines far exceed surface mining that is more common in the PRB).

To address these shortcomings, we calculate the average cost of methane emissions from U.S. surface and underground mining from 2005 to 2009. To calculate average U.S. surface and underground mine emissions, we divided total surface and underground coal mine emissions data from EIA (2009, Table 18) by the corresponding production data from EIA (2009). We then multiplied average surface and underground mine methane emissions by the official EPA social cost of methane estimates (Marten et al, 2015)—which are consistent with the official US social cost of carbon (IWG, 2013).⁴⁸ Given that the PRB exclusively uses surface mining techniques, we set the average cost of methane emissions from coal mining in the PRB equal to the average cost of methane emissions from U.S. coal surface mines over 2005 to 2009: a range of \$0.44 to \$2.74 per metric ton of coal mined in the PRB with a most likely value of \$0.98 per metric ton coal mined (see Table B5). These estimates—like the social cost of carbon and methane—represent a lower bound estimate of the impacts of climate change (Revesz et al., 2014; Howard et al., 2014).⁴⁹

The above methane cost estimates only represent the average cost of methane emissions from a unit of PRB coal extracted in 2015.⁵⁰ Given that greenhouse gas emissions are a stock pollutant, the social costs of carbon and other GHG (including methane) increase over time. As a consequence, the external cost of methane emission from coal also increases over time for a given level of emissions level. If the Department of the Interior is to set royalty rates based on a broader definition of fair return (see Appendix A), analysts should adjust the royalty rate upwards over time to account for this increasing cost. Specifically, analysts should use the social cost of methane in the year that the royalty rate is charged (i.e., the year that the methane is emitted).

Non-greenhouse gas pollution. Due to the significance of health impacts of air pollution from coal combustion, non-greenhouse gas air pollution has been the focus of most lifecycle models of coal. To model these costs, studies: (1) model the amount of emissions from various stages of electricity production from coal, (2) model the dispersion of the relevant pollutants (i.e., increases in ambient concentrations within the geographic scope of the study), (3) convert the increase in ambient levels into impacts using dose response functions (e.g., declines in crop yields and increases in mortality), and (4) value these impacts (e.g., using the market price of a crop or the value of a statistical life) (Berry et al., 1998). Most of the costs of air pollution come from downstream emissions—the combustion of coal at power stations—and thus studies tend to mostly ignore emissions at the downstream—i.e., mine and transportation stages.

Even so, Nkambule and Blignaut (2012) estimate that human health damages due to air pollution from coal mines and transport in South Africa. They find that these costs are 15 fold higher than the human health costs due to public accidents from coal transport and 2% of damages from methane emissions from coal mining.⁵¹ However, these damages are highly site specific given that they are dependent on the emissions relationships to surrounding populations—i.e., population densities—unlike impacts from greenhouse gas emissions.

Ideally, models for the Wyoming region should be developed to estimate this impact. Alternative, benefit transfer methods can be used to transfer air pollution impact estimates from other study regions to Wyoming. One way to do this is to use the breakdowns in air pollution between mining, transportation, and combustion in Table B2, B7, and B17 of Spath

et al (2012) to extrapolate U.S. air pollution damage estimates from other studies that estimate the lifecycle air pollution impacts of coal mining. More work is necessary to operationalize this methodology. Given the low density of the Wyoming region, these impacts are likely to be small.

Water pollution. All of the recommended models analyze water pollution (Burtraw et al., 2012), though Rowe et al (1995) places particular emphasis on non-air pollution (Krupnick and Burtraw, 1996). However, Krupnick and Burtraw (1996) identify damages to aquatic ecosystems and to groundwater as two of the key omitted impacts from lifecycle models.⁵² Maybe for this reason, Rowe et al (1997) finds that externalities from air pollution far exceed that of water pollution.⁵³

Epstein et al (2011) value only a portion of water pollution—in particular carcinogens from coal mines and power plants. Using health impacts in terms of disability-adjusted life years (drawn from NRC (2010)), the study provides a lower bound estimate of \$11.776 billion in 2008 USD for the health costs of carcinogen emissions from the lifecycle of coal—of which 94% are water emissions. This implies that costs to human health from water based emissions of carcinogens are approximately \$14 per metric ton of coal in 2005. It is unclear what portion of these costs is due to upstream or downstream emissions, though it appears to be mostly from power plant waste.

Nkambule and Blignaut estimate the cost of water pollution—specifically the emission of sulphates that cause acid mine drainage—for a South African mine. They calculate these costs by multiplying the quantity of sulphate emissions (a function of the quantity of coal) by the damage estimates drawn from the literature. These numbers do not specifically apply to the PRB because (1) acid mine drainage applies more to coal mines in the Eastern United States than Wyoming (see Appendix A), and (2) the resulting damage cost estimates are based on South African based studies. However, their small magnitude indicates water pollution from coal mines are relatively insignificant compared to the overall external cost of mining.

Given that water pollution is site-specific, ideally models for the Wyoming region should be developed to estimate this impact. One inexpensive way is to use benefit transfer methods to transfer water pollution impact estimates from other study regions to Wyoming. One possible method is to use the breakdowns in water pollution between mining, transportation, and combustion in Table B3, B8, and B18 of Spath et al (2012) to extrapolate U.S. water pollution damage estimates from other studies that estimate lifecycle water pollution impacts for coal mining. More work is necessary to operationalize this methodology. However, given the low density of the Wyoming region and the above evidence, these impacts are likely to be small.

Water Use. Of the recommended models, none of them estimate the social cost of inefficient water use by mines, except EXMOD according to Freeman and Rowe (1995); though no specific estimates were identified. Additionally, Berry et al. (1995) and Berry et al. (1998) mention it as an omitted externality from the 1995 version of ExternE. Nkambule and Blignaut is the sole study to identify and estimate the external impact of water consumption. Their calculation method was to: (1) calculate the quantity of water used by the coal mine, (2) calculate the opportunity cost (or shadow price) of water (i.e., the price of water if there was an efficient market), (3) adjust this cost to a per unit basis, and (4) multiply the quantity and price. In their study of a new South African mine, they find that the external cost of water use by coal mines accounts for 90% of all external costs in their study. Given the potential significance of this cost component, future U.S. studies should attempt to estimate the external cost of water consumption by Wyoming coal mining operations.

Transportation—External Variable Cost of Coal Mining

In Appendix A, we identified several impacts from the transportation of coal: greenhouse gas emissions, other air pollution, public fatalities, and disamenities from rail transport. As will be demonstrated in this sub-section, there are monetary estimates for most of these impacts in the transportation literature. However, as an application to coal in the PRB, it is unclear if current estimates of the external travel cost of coal are overestimates or underestimates. On the one hand, there is a fundamental assumption of non-displacement in rail traffic from decreased coal in most studies (Lee et al., 1995, p. 9-2). While this implies an over-estimation of costs, we will maintain this assumption to simplify the externality calculation. On the other hand, given that travel distances for coal from the PRB are higher than average travel distance for coal in the United States (EIA, 2015) and travel costs increase with distance traveled, they represent underestimations. When possible, we try to correct for this latter deficiency in the literatures' estimates.

Given that few to none of the empirical estimates of upstream externalities from coal apply directly to the PRB, we have approximated them by adjusting average U.S. estimates from the literature using a conversion method. Most transportation external cost estimates are cost per ton-mile estimates for U.S. freight rail transport, while we are interested in the average cost of coal shipped from the PRB. There are four steps to convert cost estimates to the appropriate units. First, we convert cost per ton-mile of U.S. freight to total costs by multiplying by total ton-miles of U.S. freight (averaged from 1999 to 2003).⁵⁴ Second, we multiply the cost estimate by the share of total freight train ton-miles carrying coal to convert from total U.S. freight to U.S. coal freight. We choose to use an estimate of 45% to reflect the portion of freight that is coal, given that 39% to 44% of freight train tonnage was coal according to U.S. DOT (2012) and AAR (2011-2014)⁵⁵ and 43% to 50% of ton-miles were coal according to NRC (2011) and U.S. DOT (2012).⁵⁶ While some may argue that 50% should be chosen given its appropriateness as a metric and its most recent date, the U.S. coal tonnage (and likely ton-miles) has recently declined making a slight adjustment downwards more appropriate.⁵⁷ Third, we multiply this by Wyoming's share of U.S. coal ton-miles (approximately 80% using data from EIA (2015)) to convert from U.S. coal freight to Wyoming coal freight.⁵⁸ Last, we divide the resulting cost estimate by annual metric tons of coal produced in Wyoming (averaged from 1999 to 2003) to convert from a total cost estimate to an average cost estimate.^{59,60} In cases where a total U.S. cost estimate was provided (instead of costs per ton-mile), only steps two through four are necessary to calculate the average transportation externality cost per ton of Wyoming coal produced.

GHG emissions. To our knowledge, none of the recommended studies (in the lifecycle literature) estimated the monetary value of greenhouse gas emissions from transport. However, the transportation literature produces several social cost estimates for the emission of greenhouse gases by U.S. freight trains. While Delucchi and McCubbin (2010) rate the quality of these estimates as good, only one study—Austin (2015)—uses the official U.S. social cost of carbon estimates. In the lifecycle literature, Spath et al (1999) estimates the non-monetary impacts of coal in a lifecycle analysis of an average U.S. coal-fired power plant assuming two different types of mining (surface and underground) and three different forms of transportation (railroad, water, and trucks). For their average plant, they estimate that upstream emissions account for 4.4% of total GHG emissions, of which only 43% comes from methane leakage. The remaining 56% is split between GHG emissions from the mining operation (18%) and transport (39%) (Odeh and Cockerill, 2008). While Spath et al (1999) is the sole U.S. study that we are aware of that estimates the amount of upstream GHG emissions in addition to methane leakage, the importance of non-methane leakage sources in their study—while indicating a need for further study—differs from other studies. This may be partly due to longer travel distances assumed, which is based on transport distances for Perry County, Pennsylvania.⁶¹ Given that travel distance is larger for Wyoming coal than Pennsylvania coal—the average trip is almost three times longer and the ton-miles are 49 times higher⁶²—Spath et al (1999) may actually underestimate the share of GHG emissions due to transport for public U.S. mines.

As mentioned in the previous paragraph, several studies on other nations have estimated the quantity and/or cost of GHG emitted in the transport of coal. First, Nkambule and Blignaut (2012) calculate these costs for a new coal power plant in South Africa—the Kusile coal fired power station. With respect to this plant, the authors find that approximately 0.5% of the external costs of GHG emissions are from transporting coal. Second, in a Japanese study, Hondo (2005) estimates that 12.5% and 20% of upstream GHG emissions—which account for 8% of total GHG emissions—come from CO₂ emissions from mining equipment and transportation, respectively. Last, Odeh and Cockerill (2008) estimate that 11% of upstream GHG emissions for “existing UK pulverized coal power plants” come from CO₂ emissions from mining and transportation; upstream emissions account for 7.3% of GHG emissions in the study. While estimates may seem contradictory to Spath et al (1999), these studies analyze CO₂ emission from rail transport in relatively small nations compared to the United States. While South Africa appears to be an exception the first study (i.e. it is a relatively large nation), the majority of coal comes from the New Largo coal reserve—an area extremely close to the station—in this particular case (Nkambule and Blignaut (2012)).

The transportation literature—on the other hand—provides several estimates of the cost of CO₂ emissions: Forkenbrock (2011), Delucchi and McCubbin (2010), and Austin (2015).⁶³ This literature estimates this social cost on a ton-mile basis using a variety of SCC estimates. For our purposes, we convert these estimates to cost per metric ton of Wyoming coal mined utilizing the methods discussed at the beginning of this sub-section. Additionally, we update the studies estimates by (1) converting their SCC estimates to the appropriate 2015 SCC estimates from the IWG (2015), and (2) updating their estimates to 2015 USD. The resulting estimates are \$1.33 (Forkenbrock, 2011), \$2.07 to \$12.58 (Delucchi and McCubbin (2010), and \$0.82 to \$3.91 (Austin, 2015).

Given the wide range of estimates, we provide our own estimates of the external cost of CO₂ emissions from transporting Wyoming coal. Using 2013 greenhouse gas emissions of 41.3 million metric tons of CO₂ equivalence for U.S. railroad freight (AAR, 2015),⁶⁴ we calculate the total social cost of U.S. freight rail CO₂ emissions by multiplying these emission estimates by the official U.S. social cost of carbon estimates for 2015 emissions (IWG, 2015).⁶⁵ Then utilizing the methodology specified in the beginning of this sub-section, we convert these total U.S. cost estimates to average Wyoming cost estimates. Specifically, we find an average external cost from greenhouse gas emissions from the transportation of Wyoming coal by freight train of \$1.75 per metric ton of Wyoming coal mined (2015 USD) with a range of \$0.56 to \$5.17. While these estimates are in the same range as previous estimates, all estimates should be interpreted as lower bounds given that U.S. social cost of carbon estimates are lower bounds (Revesz et al., 2014; Howard et al., 2014) and they exclude emissions from the international transportation of Wyoming coal.

These external costs will likely increase over time. First, because carbon dioxide is a stock pollutant, the social cost of carbon increases over time; see IWG (2015). Second, the EPA introduced a regulation in 2008 that aims to reduce air pollution—particularly particulate matter and ozone—from diesel run trains starting in 2015 (EPA, 2008a). This regulation will slightly increase fuel consumption, and thus greenhouse gas emissions per mile-ton of Wyoming coal shipped (EPA, 2008c). However, additional EPA regulations—such as incentives to idle trains (EPA, 2013)—may decrease greenhouse gas emissions per mile-ton of coal in the medium to long-run. Given this uncertainty, the current estimate may only be a good approximation of this external cost in the short-run.

Other air pollution. Trains also contribute to non-greenhouse gas air pollution. In 2006, EDF (2006) calculated that emissions from class I trains (i.e., freight trains) caused 3,400 deaths and 290,000 lost working days by releasing approximately a million tons of ozone forming oxides of nitrogen (COX)—7.2% of transportation sector emission—and 32,000 tons of PM_{2.5} -5.6% of transportation emissions (EDF, 2006). However, air pollution from the transportation

of coal is given less emphasis in the lifecycle literature due to the oversized impact of combustion on air pollution. The transportation literature places particular emphasis on estimating the health (mortality and morbidity) costs of air pollution—particularly particulate matter and NOX—from transporting U.S. freight, and has produced several cost estimates. Delucchi and McCubbin (2010) rate the quality of these estimates as fair. None of these estimates accounted for a 2008 EPA rule (EPA 2008a; EPA 2008b)⁶⁶ that regulated air borne emissions—particulate matter and ozone causing emissions—from diesel freight trains.

There are four transportation studies that estimate the cost of damages due to air pollution—predominately PM and NOX—using differing methodologies. Forkenbrok (2001) estimates the health (mortality and morbidity) and non-health (materials, agriculture, and aesthetic quality) costs of three air pollutants—volatile organic compounds, NO_x, and PM₁₀—to be \$0.0001 to \$0.0002 per ton-mile of U.S. freight. Accounting for a possible 17% to 39% decline in impacts due the 2008 EPA regulation of freight trains (EPA, 2008b), this is equivalent to \$0.16 to \$0.42 per metric ton of Wyoming coal produced. Delucchi and McCubbin (2010)—reproduced in Appendix IV of GAO (2011)—cite Forkenbrock (2001) estimate as the lower boundary of their range of air pollution externality estimates.⁶⁷ This GAO (2011) report estimates the external health cost of U.S. freight transport from the emission of two air pollutants—NO_x, and PM₁₀—to be \$0.008 (2010 USD) per mile-ton. Accounting for a possible 13% to 24% decline in emissions from 2010 to 2015 due the 2008 EPA regulation (EPA, 2008b), this is equivalent to \$10.51 to \$12.00 per metric ton of Wyoming coal produced. Third, Austin (2015)—a Congressional Budget Office Working paper—estimates that the external health costs of air pollution—PM and NOX pollutants—from U.S. freight trains is between \$0.0013 to \$0.0024 (2014 USD) per ton-mile.⁶⁸ Accounting for a possible 17% to 39% decline in impacts due the EPA regulation (EPA, 2008b), this is equivalent to \$1.28 to \$3.18 per metric ton of Wyoming coal produced. Finally, EDF (2006)—using the mortality and morbidity impact estimates discussed in the previous paragraph—estimates an impact of \$23.2 billion in damages in 2000 USD using an EPA methodology; this implies a cost of \$25 per ton of Wyoming coal extracted in 2015.⁶⁹ The above estimates provide a wide range of health costs from transporting Wyoming coal by rail: \$0.16 to \$25 per metric ton with a best estimate of approximately \$3.18.

Given this wide range of impact estimates, we calculate three impact estimates of our own. First, using the median costs estimates from Table 4 of Mathews et al (2015) and the EPA (2008b) emissions under the control scenario, we estimate the health costs from PM, NOX and VOC emissions from US freight. Then, using the methodology discussed above we convert these impacts to a cost estimate on a per metric ton of Wyoming coal basis. Specifically, we find a cost of \$1.29 and \$1.33 per metric ton of Wyoming mined; this is almost identical to the lower bound of Austin (2015). Second, using the mean cost estimates from Table 4 of Mathews et al (2015), we redo this analysis, and find a range of \$3.13 to \$3.24 per metric ton of Wyoming mined. Again, this is almost identical to the upper bound of Austin (2015) implying similar calculation procedures. Third, assuming an approximately linear health damage curve, we divide the U.S. EPA benefit estimates in 2020 and 2030 for the 2008 EPA regulation (EPA, 2008a) by the corresponding estimate of the percent reduction of PM and NOX (EPA, 2008b, Table 6.7-1). Using the conversion method discussed at the beginning of the sub-section, we calculate the benefits to be approximately \$6 to \$8 per ton of Wyoming mined. Given that benefits from emissions reductions are likely decreasing in emissions reductions, this latter estimate is probably an over-estimate and the \$3.18 per metric ton estimated by Austin (2015) is the most appropriate. However, given that the GAO (2011) used an EPA approved valuation method, we set this value as the upper boundary estimate—i.e., \$12—instead of the \$6 estimate, and discard the EDF estimate as an outlier.

Public Fatalities. All of the recommended studies account for public mortality and morbidity from the transport of coal, though only ExternE, Lee et al (1995),⁷⁰ NRC (2010), and Epstein et al. (2011) monetize them and only the latter

two utilize the EPA's official value of statistical life of \$8 million in 2010 USD (Burtraw et al., 2012). Similarly, the train externality literature consistently provides estimates of this externality. Given the large number of estimates, we only focus on the most up-to-date empirical estimates in the life-cycle literature—NRC (2010) and Epstein et al. (2011)—and transportation literature—GAO (2011) and Forkenbrock (2001)). All of the studies use the ratio of total US freight ton-miles (or miles) to US freight miles carrying coal to convert public fatalities from accidents due to US freight to accidents to U.S. freight carrying coal. This analysis assumes that: (1) train speed is unlikely different for coal compared to other freight, and (2) train length is unimportant in determinants of fatalities (since the vast majority of fatalities are due to being struck by the train).⁷¹

In the lifecycle literature, NRC (2010) estimates the cost of fatal and non-fatal injuries from coal trains in the United States. The authors multiply deaths by freight by the proportion of ton-miles of coal (i.e., 43%)⁷² and then the VSL (\$6 million in 2000 USD); they find the U.S. external cost is \$2 billion, or approximately \$2 per metric ton (\$1.74 per short ton). As in the case of air pollution, this estimate likely underestimates the externality of Wyoming coal which travels farther distances than average U.S. coal. Given that Wyoming accounts for 80% of U.S. coal shipped by freight in terms of ton-miles, the cost per ton of Wyoming coal is \$4.33 in 2015 USD for a metric ton of Wyoming coal. Epstein et al (2011) base their estimates on NRC (2011), and come to the same result. The authors assume that none of the public accident cost is internalized by payoffs or insurance, compared to an internalization rate of 4.7% assumed by Lee et al (1995).⁷³

The transportation literature has produced several comparable estimates. Forkenbrock (2001) estimates a cost of \$0.0017 (1994 USD) per ton-mile accounting for fatalities, injuries, and property loss, and deducting internalized property damages (via claims), or \$4.34 per ton of coal produced in Wyoming. However, this estimate uses a lower value of statistical life than the EPA and accounts for injuries and compensation to employees. If we address these shortcomings, the cost per ton of Wyoming coal increases to between \$7.58 and \$9.95 depending on how we treat employee compensation. Given that accidents due to train accidents have declined over time (GAO, 2011), it unsurprising that the resulting impact estimates are higher than Epstein et al. (2010). Assuming a 50% internalization of mortality costs into railroad decision making (based on a survey of four papers) and the official value of statistical of the U.S. Department of Transportation, the GAO (2011) estimates an external cost of rail accidents of \$0.0011 (2015 USD) per mile-ton of US freight, or \$1.73 per ton of Wyoming coal produced. While the GAO (2011) assumes the lower bound on the range of cost internalization that they found in their survey of estimates (i.e., 50% to 62%), this percentage is far higher than the 4.7% used by Lee et al (1995) and the 3% to 38% used by Forkenbrock (2001).

As a central estimate, we modify the Epstein et al (2011)/NRC (2009) calculation by assuming that 40% of the costs of rail accidents are internalized by the freight rail companies.⁷⁴ Thus, we assume the best estimate of the external cost of accidents is \$2.93 per metric ton of Wyoming coal extracted. The GAO (2011) estimate makes up the lower range of externality estimates, while our adjusted Forkenbrock (2001) estimate makes up the upper range.

Disamenities. Of the recommended studies, only ExternE and Lee et al (1995) consider the cost of noise and none of the models consider congestion (Burtraw et al., 2012).⁷⁵ However, only Forkenbrock (2001)—from the transportation literature—provides an empirical estimate of the external cost of noise from U.S. freight trains. Similarly, Gorman (2008) represents the only estimate of the cost of traffic congestion (i.e., motor vehicle traffic) of US freight trains. Both estimates are cited by Delucchi and McCubbin (2010) and reprinted in Appendix IV of GAO (2011). Delucchi and McCubbin (2010) consider the quality of these estimates to be poor.

Forkenbrock (2001) estimates the external cost of freight train noise in rural areas of the United States. He assumes that the cost is identical in magnitude to the external cost of freight truck noise in rural United States estimated in Forkenbrock (1999). He estimates the external cost of freight train noise to the rural US to be approximately \$0.0004 per ton-mile of U.S. train freight, or \$1.02 (2015 USD) per metric ton of Wyoming coal produced. While this estimate is a lower bound from the perspective that it represents only rural costs, we assume that it presents both the best and upper bound estimate of the noise externality. Given that Delucchi and McCubbin (2010) characterize this estimate as poor quality, we set the lower bound on this impact estimate equal to \$0.

Gorman (2008) represents the sole estimate of the congestion costs of freight train traffic to U.S. drivers. Assuming that the average train speed and length are 30 miles per hour and 1 mile, respectively, Gorman (2008) calculates total minutes spent at U.S. train crossings due to freight trains. Assuming an annual U.S. hourly wage of \$20, he calculates the external cost of traffic congestion to be \$0.00034 dollars. It is unclear whether Gorman is using 2000 or 2007 USD, so we calculate a range of \$0.62 to \$0.74 (2015 USD) per metric ton of coal produced in Wyoming using the methods describe at the beginning of this sub-section. Again, given that Delucchi and McCubbin (2010) characterization of this estimate as poor quality, we set the lower bound on this impact estimate equal to \$0 and assume \$0.62 is the best estimate available. Loss of public infrastructure. Train traffic erodes pavement at railroad crossings. While these costs are small compared to the wear and tear of public roads by freight trucks and the significant private costs of train track maintenance, these costs are not insignificant (Austin, 2015). Using GAO (2011) damage estimates based on Federal Highway Administration studies, Austin (2015) cites an external cost of pavement maintenance of between \$0.0005 and \$0.0006 per ton-mile; this cost is between \$0.80 and \$0.96 per metric ton of Wyoming coal produced. Like the estimates of the external cost of disamenities, we set a lower bound of \$0 for the cost of this externality.

Total Estimates

Few to none of the empirical estimates of upstream externalities from coal apply directly to the PRB or represent complete external impact estimates. Keeping this in mind we review, the total estimates of externality from coal mining in the United States.

The most complete estimate in the life-cycle literature—Epstein et al (2011)—estimates the external cost of U.S. coal mining on a per tonnage basis. Using them, the best external fixed and variable cost estimates for coal mining in the United States are \$0.44/metric ton of coal and \$5.06/metric ton of coal, respectively, in 2015 USD; see Table B1. Based on a broader definition of fair market value, these total externality estimates should be interpreted as estimates of the external cost of upstream US coal production on a per metric ton of U.S. coal produced, solely considering impacts relevant to the PRB (i.e., we exclude water pollution from processing). These results imply a royalty rate increase of 4.6% to 5.5% to account for production externalities depending on whether royalty rates are determined at the power plant or mine-mouth levels, respectively, and 8.0% to 9.6% if transportation externalities are considered.

In addition to the estimate provided by Epstein et al. (2011), the external cost of U.S. freight borne by the U.S. public on a per mile-ton basis are provided in Table B2. Using the method discussed at the beginning of the previous section, we adjust them to reflect the external cost of freight trains carrying Wyoming coal; see Table B3. Given the more complete transportation externalities, the best estimate of the ratio of transportation externality to private transportation costs is 50% for PRB coal. This suggests that current deductions in royalty rates due to transportation of coal (which is allowed in the rare case when the final sales price to the power plant is used instead of the mine-mouth price to determine the royalty payment) should be eliminated—or at a minimum capped—given that such transportation externalities are significant.

Suggested minimum bid and royalty rate increases in the PRB. We assembled our best estimates of external-ity estimates for the PRB in Tables B4 and B5 following the discussion above. Because minimum bids and royalty rates should be adjusted to capture the fair return to coal production—as discussed in Appendix A—our estimates inform our suggested increases in the minimum bid and royalty rate increases in the PRB.

Accounting solely for the cost of the unfunded rehabilitation of abandoned mine, our best estimate of the fixed costs of mining—and thus our suggested per metric ton minimum bid increase to capture a fair return for the American public—in the PRB is \$0.44 per metric ton of coal mined; see Table B4. Because we were unable to find Wyoming specific data, we essentially assume that the fixed cost estimate of coal mining in the PRB is identical to the United States (as represented by Epstein et al. (2011) estimate in Table B1). Given that this estimate excludes two significant impacts—lost amenities to the public from the mining company obtaining the rights to and mining a particular area and the option value corresponding to the uncertainty surrounding the fixed and variable external cost estimates (as characterized by the low, best, and high estimates in Table B5)—the U.S. government should arguably increase the minimum bid by an amount greater than \$0.44 per metric ton of coal.

Accounting solely for methane emissions from coal mining (i.e., the sole production variable externality cost that we were able to accurately measure), our best estimate of the variable cost of mining in the PRB is \$0.98 per metric ton of coal mined with a range of \$0.44 to \$2.74; see Table B5. Using the average mine-mouth price in Wyoming from 2009 to 2013, our suggested increase in Wyoming’s surface mining royalty rate in order to provide a fair market return to the market public is 6.2% (with a range of 2.8% to 17.4%). From 2009 to 2013, an increase in the royalty rate of this magnitude would have raised \$600 million to \$1.2 billion (2015 USD) in additional government revenue;⁷⁶ see Table B6. Accounting for the benefits to the U.S. public in terms of increased revenue and decreased externalities from coal mining, this increase would have provided the US public with \$1.6 billion in additional benefits from 2009 to 2013.⁷⁷

While the mine-mouth price is often used, some experts have advocated for the use of the final sales price—i.e., the price of coal delivered to the US power sector—as an alternative to the mine mouth price for reasons of transparency. If we use the US power plant price, this percentage increase declines to 1.9% (with a range of 0.8% to 5.2%) when considering only production externalities. However, if a U.S. power plant price is used, there is a strong argument for the inclusion of the transportation externality into the fair royalty rate; this implies a royalty rate increase to 20.9% (with a range of 5.5% to 61.9%). Interestingly, these results differ from previous estimates in that most studies find that the external impact of transportation should be less than mining except with respect to energy consumption (e.g., oil) (Spath et al., 1999); this difference is due to the large distance between coal in PRB and energy users in other states.

These suggested royalty rate increases should be considered the minimum amounts necessary to capture the fair return to the American public. First, these estimates of the variable cost of mining exclude several key production externalities: air pollution, water pollution, and water use. Second, the social cost of methane and carbon omit key climate impacts, implying that they represent lower bounds (Revesz et al., 2014; Howard, 2014). As a consequence, the external costs of methane leakage from coal production and greenhouse gas emissions from transporting coal are lower bound estimates. Third, the social cost of methane and CO₂ increase over time because greenhouse gases (GHG) are stock pollutants (Marten et al., 2015; IWG, 2015). Rising methane costs will increase the cost of methane leakage in the future, while an increasing social cost of carbon will lead to rises in the cost of GHG emissions from freight trains carrying coal from the PRB to market. In both cases, improvements in technology—such as methane capture and reduced emissions from trains—may have an opposing effect in the medium run. Last, our royalty rate increase estimates fail to capture the mar-

ket value of methane as natural gas. This omission makes less of a difference in the PRB case due to the prevalence of surface mining for which carbon capture is currently unavailable, as compared to underground mining.

Suggested minimum royalty rate for Western coal mining states. Four states in the Western United States contain relatively large coal mining operations on public lands: Colorado, Wyoming, Utah, and Montana. In Wyoming and Montana, approximately 95% of coal is mined in the Powder River Basin. In Utah and Colorado, the Uinta Basin makes up approximately 85% of coal mining production. In this sub-section, we calculate the suggested royalty rate increase for surface and underground mining for each of these states and these two corresponding basins.

We calculate a suggested royalty rate for these regions in three steps. First, using the EIA (2011) and EPA (2015) estimates of methane emissions for the 2005 to 2009 period and 2009 to 2013 periods, respectively, we calculate the average US emissions per metric ton of US coal production by mining method; see Tables B7 and B8. Second, we multiply these emissions levels by the social cost of methane (Marten et al., 2015) for 2015 emissions corresponding to a 3% discount rate to calculate the external cost of methane emissions from the average metric ton of U.S. coal produced in surface and underground mines. Last, we divide these external costs by the average mine-mouth price by state and the average U.S. price of coal delivered to the electric power sector from 2009 to 2013 to calculate the suggested royalty rate increase corresponding to the first arm's length transaction (i.e., mine-mouth) and final transaction (i.e., power plant), respectively. See Table B9 and B11. Government revenue from increasing royalty rates in these four Western state coal regions by our suggested amount would have totaled to between \$550 million and \$2 billion from 2009 to 2013;⁷⁸ see Table B13. Accounting for the benefits to the U.S. public in terms of increased revenue and decreased externalities from coal mining, this increase would have provided \$2.9 billion in additional benefits from 2009 to 2013.

Underground mines clearly emit more methane emissions than surface mines—by a factor of 9 or more—after accounting for methane capture. As a consequence, underground mines should face a higher royalty rate than surface mines. Our results suggest that states with predominately underground mining operations such as Colorado and Utah should face a royalty rate of approximately 3.5 times higher than states with predominately surface mining such as Wyoming and Montana—as suggested by the ratio of royalty rates for underground mining in the Uinta Basin to surface mining in the Powder River Basin.

If royalty rates are based solely on the external cost of methane emissions, all royalty rates should increase over time to account for the rising cost of emitting greenhouse gases. Schedules are provided in Tables B10 and B12.⁷⁹

Uncertainty

There are uncertainties at every level of the model of impacts from coal. This includes statistical uncertainty over the estimates used to parameterize emissions, impacts, and their monetary values. These are often characterized using the standard errors of the cited estimates. Additionally, there is uncertainty over the particular estimates chosen—I.e., uncertainty over whether to choose one particular estimate with respect to another—and other modeling decisions, including the necessary approximation and simplification necessary in modeling. Finally, there is uncertainty over the omitted impacts (Berry et al., 1995; Krupnick and Burtraw, 1996).

All of the recommended models address uncertainty differently. Lee et al (1995) and Rowe et al (1995) use Monte Carlo simulations. Berry et al (1995) address uncertainty through expert elicitation—though only for qualitative analysis

(Krupnick and Burtraw, 1996). Epstein et al (2011) provides a range of estimates (low and high estimates) in addition to their best estimate. Each of these methods has their relative advantages and disadvantages.

The uncertainty over the resulting cost estimates implies an option-value from delaying mining of a tract. Appendices C to E discuss how to calculate option value corresponding to coal mining. It should be noted that the methods available to the analyst for calculating option value partly depends on how uncertainty is specified. Given that the agency may be interested in calculating option value in a particular way, an effort should be made to calculate uncertainty in a way that makes their calculation method possible.

TABLE B1. Estimates of the Fixed and Variable External Costs of Coal Mining on U.S. Public Lands – Based on Epstein et al (2011) estimates

Relevant Category	Low	Best	High	Units
Abandoned mine lands (AMLs)	\$0.44	\$0.44	\$0.44	2015 USD/metric ton
Methane emissions from mines	\$0.89	\$2.92	\$8.52	2015 USD/metric ton
Fatalities to public due to coal transport	\$2.14	\$2.14	\$2.14	2015 USD/metric ton
Total Costs				
Total fixed external costs	\$0.44	\$0.44	\$0.44	2015 USD/metric ton
Total variable external costs	\$3.04	\$5.06	\$10.66	2015 USD/metric ton
Royalty Rate Adjustment - Production Only				
Average US surface mine gate price	1.4%	4.6%	13.5%	Externality Royalty Rate
US power plant price	1.7%	5.5%	16.2%	Externality Royalty Rate
Royalty Rate Adjustment - Production and Transport				
Average US mine-mouth price	6.9%	11.6%	24.3%	Externality Royalty Rate
Average US Price of Coal Delivered to the Electric Power Sector	5.8%	9.6%	20.2%	Externality Royalty Rate
Transportation Externality as Ratio of Market Transportation Costs				
Transportation Ratio of Average Costs	10%	10%	10%	% of Externality in Transport

TABLE B2. Review of Transportation Literature U.S. Freight Rail Externality Estimates by Author and by Externality Type (2015 USD per ton-mile)

Studies	GAO (2011)		Delucchi and McCubbin (2010)		Austin (2015)		Forkenbrock (2001)		Gorman (2008)	
	Low	High	Low	High	Low	High	Low	High	Low	High
Congestion delay	–	–	\$0.0004*	\$0.0004*	\$0.0000	\$0.0003*	–	–	\$0.0004	\$0.0005
Accident	\$0.0011	\$0.0011	\$0.0026**	\$0.0026**	\$0.0011***	\$0.0026**	\$0.0027	\$0.0095	–	–
Air pollution, health	\$0.0087	\$0.0087	\$0.0001**	\$0.0041****	\$0.0013	\$0.0024	\$0.0002	\$0.0013	–	–
Climate change	–	–	\$0.0001	\$0.0055	\$0.0001	\$0.0005	\$0.0003	\$0.0024	–	–
Noise	–	–	\$0.0006**	0.0006**	–	–	\$0.0006	\$0.0006	–	–
Pavement Damage	–	–	–	–	\$0.0005***	\$0.0006***	–	–	–	–

*Cite estimate from Gorman (2008)
**Cite estimate from Forkenbrock (2011)
***Cite estimate from GAO (2011)
****Cite estimate from Zhang et al. (2004) – a Canadian based estimate

TABLE B3. Review of Transportation Literature U.S. Freight Rail Externality Estimates by Author and by Externality Type (2015 USD per metric ton of Wyoming coal produced)

Studies	GAO (2011)		Delucchi and McCubbin (2010)		Austin (2015)		Forkenbrock (2001)		Gorman (2008)	
	Low	High	Low	High	Low	High	Low	High	Low	High
Congestion delay	–	–	\$0.56*	\$0.56*	\$0.00	\$0.48*	–	–	\$0.62	\$0.74
Accident	\$1.73	\$1.73	\$4.12**	\$4.12**	\$1.76***	\$4.12**	\$7.58	\$9.95	–	–
Air pollution, health	\$10.51	\$12.00	\$0.11**	\$5.42****	\$1.28	\$3.18	\$0.16	\$0.42	–	–
Climate change	–	–	\$2.21	\$12.34	\$0.80	\$3.85	\$1.31	\$1.31	–	–
Noise	–	–	\$0.94**	\$0.94**	–	–	\$1.02	\$1.02	–	–
Pavement Damage	–	–	–	–	\$0.80***	\$0.96***	–	–	–	–
Total	\$12.24	\$13.73	\$7.94	\$23.38	\$4.64	\$12.48	\$10.07	\$12.70	\$0.62	\$0.74
Ratio of Transportation Externality to Private Transportation Costs										
Ratio	55%	62%	36%	106%	21%	56%	45%	57%	3%	3%

*Cite estimate from Gorman (2008)
**Cite estimate from Forkenbrock (2011)
***Cite estimate from GAO (2011)
****Cite estimate from Zhang et al. (2004) – a Canadian based estimate

TABLE B4. Fixed Costs of Mining and Suggested Per Metric Ton Minimum Bid Increase in the Powder River Basin (and the United States)

Relevant Category	Low	Best	High	Units	Source
Obtaining Mining Rights					
Amenities	–	–	–	2015 USD/ metric ton	–
Abandoned mine lands (AMLs)	\$0.44	\$0.44	\$0.44	2015 USD/ metric ton	Epstein et al (2011)
Option Value	–	–	–	2015 USD/ metric ton	–
Minimum Bid Increase					
Fixed External Costs	\$0.44	\$0.44	\$0.44	2015 USD/ metric ton	–

TABLE B5. Externality Costs and Suggested Royalty Rate Increases in the Powder River Basin (PRB)

Relevant Category	Low	Best	High	Units	Source
Production					
Methane emissions from mines	\$0.44	\$0.98	\$2.74	2015 USD/ metric ton	Authors estimate
Air Pollution from mining	–	–	–	2015 USD/ metric ton	–
Water Pollution	–	–	–	2015 USD/ metric ton	–
Water Use	–	–	–	2015 USD/ metric ton	–
Transportation					
Fatalities to public due to coal transport	\$1.73	\$2.64	\$9.95	2015 USD/ metric ton	GAO (2011); Epstein et al (2011); Forkenbrock (2001)
GHG emissions from trains	\$0.56	\$1.75	\$5.17	2015 USD/ metric ton	Authors estimate
Air pollution from trains	\$0.16	\$3.18	\$12.00	2015 USD/ metric ton	Forkenbrock (2011); CBO (2015); GAO (2011)
Congestion	\$0.00	\$0.62	\$0.74	2015 USD/ metric ton	CBO (2015); Gorman (2008); Gorman (2008)
Noise	\$0.00	\$1.02	\$1.02	2015 USD/ metric ton	Zero; Forkenbrock (2001); Forkenbrock (2001)
Pavement	\$0.00	\$0.80	\$0.96	2015 USD/ metric ton	Zero; CBO (2015); CBO (2015)
Total Costs					
Variable external costs	\$2.88	\$10.99	\$32.58	2015 USD/ metric ton	EIA Coal Report – Table 28
Royalty Rate Increase - Production Only					
Wyoming mine-mouth price	2.8%	6.2%	17.4%	Externality Royalty Rate	EIA Coal Report – Table 28
Average US surface mine-mouth price	1.5%	3.3%	9.3%	Externality Royalty Rate	EIA Coal Report – Table 28
Average US Price of Coal Delivered to the Electric Power Sector	0.8%	1.9%	5.2%	Externality Royalty Rate	EIA Coal Report – Table 24
Ratio of Transportation Externality to Private Transportation Costs					
Ratio	11%	45%	135%	% of Externality in Transport	EIA Coal Data

TABLE B6. Lost Government Revenue from Powder River Basin (PRB) Coal from Using Current 12.5% Statutory Royalty Rate Versus Our Estimated Rate of 18.7% (using U.S. EIA data)

Variable	Units	2013	2012	2011	2010	2009	Sum
Wyoming Price	2015 USD / metric tonne	\$15.76	\$16.32	\$15.84	\$15.32	\$15.18	–
PRB Production	Short tons (thousands)	407,567	419,066	462,600	468,428	455,503	2,213,164
PRB Production	Metric tonnes	369,738,669	380,170,389	419,663,781	424,950,855	413,225,489	2,007,749,183
PRB Revenue	2015 USD	\$5,828,371,127	\$6,206,199,834	\$6,649,227,360	\$6,509,978,130	\$6,274,599,375	\$31,468,375,826
Royalty	2015 USD	\$582,837,113	\$620,619,983	\$664,922,736	\$650,997,813	\$627,459,938	\$3,146,837,583
Lost Royalty (EIA) Revenue from PRB*							
Perfectly Inelastic Supply	2015 USD	\$290,343,838.48	\$309,165,604.39	\$331,235,289.00	\$324,298,504.25	\$312,572,969.00	\$1,567,616,205
Elasticity of 1	2015 USD	\$228,203,784	\$242,997,273	\$260,343,553	\$254,891,394	\$245,675,385	\$1,232,111,389
Elasticity of 3	2015 USD	\$103,923,675	\$110,660,609	\$118,560,080	\$116,077,175	\$111,880,217	\$561,101,756

*These estimates account for inflation, but not discounting. If we were to discount, the resulting estimates would be higher.

Source: Share of coal mine production on public lands by states comes from <https://www.wyden.senate.gov/download/?id=af917fa6-4e2c-4839-bc70-05d5e495b985&download=1>.

TABLE B7. Metric Tons of Net U.S. Methane Emissions Per One Metric Ton of U.S. Coal Produced, EIA (2011) Emissions Data

Year	2005	2006	2007	2008	2009	Average
Surface	0.021	0.021	0.021	0.021	0.021	0.021
Underground	0.166	0.172	0.175	0.205	0.238	0.191
Total	0.068	0.068	0.068	0.077	0.088	0.074

TABLE B8. Metric Tons of Net and Gross U.S. Methane Emissions Per One Metric Ton of U.S. Coal Produced, EPA (2015) Emissions Data

Year	2009	2010	2011	2012	2013	Average
Surface (net)	0.021	0.021	0.021	0.020	0.020	0.021
Gross underground	0.283	0.301	0.249	0.233	0.234	0.260
Net underground	0.219	0.224	0.182	0.174	0.170	0.194
Total	0.082	0.084	0.072	0.072	0.072	0.076

TABLE B9. Suggested Royalty Rate Increases and New Royalty Rates, Based on Net Methane Emission Externality Costs (EIA, 2011) by Region-Mining Type and Geographical Scope of Price

Region	Mining Type	Suggested Increase, Using State Mine-Mouth Price	Suggested Increase, Using Average U.S. Price of Coal Delivered to the Electric Power Sector	Suggested New Royalty Rate (Using State Mine-Mouth Price)
Colorado	Underground	19.5%	16.7%	27.5%
	Surface	2.2%	1.9%	14.7%
Wyoming	Underground	56.0%	16.7%	64%
	Surface	6.2%	1.9%	18.7%
Utah	Underground	22.6%	16.7%	30.6%
	Surface	2.5%	1.9%	15%
Montana	Underground	46.9%	16.7%	54.9%
	Surface	5.2%	1.9%	17.7%
Powder River Basin (Wyoming)*	Underground	–	–	
	Surface	6.2%	1.9%	18.7%
Uinta Basin (Colorado and Utah)**	Underground	20.7%	16.7%	28.7%
	Surface	2.3%	1.9%	14.8%
* The basin is assigned the Wyoming price because Wyoming makes up the majority (approx. 90%) of production.				
** The basin is assigned a production-weighted price of Colorado and Utah.				
*** The middle two columns are suggested royalty rate increases: the first is the royalty rate increase if the state mine-mouth price is used and the second is the royalty rate increase if the average U.S. price of coal delivered to power plants is used. Currently, the mine-mouth price is used to calculate royalty payments. The last column (on the right) is the suggested new royalty rate, based on state mine-mouth prices.				
**** Emissions are measured as net emissions: total methane emissions emitted during mining and from coal pores during transport, less methane captured (based on average emissions captured for each mining type).				

Sources:

- *Methane: Methane Emissions from 2005 to 2009: Table 18 of* http://www.eia.gov/environment/emissions/ghg_report/pdf/0573%282009%29.pdf
- *EIA Production Data from 2005 to 2009: www.eia.gov/totalenergy/data/annual/pdf/sec7_7.pdf and Table 1 of:* <http://www.eia.gov/coal/annual/pdf/acr.pdf>
- *EPA Estimate of the Social Cost of Methane Used in EPA Cost Benefit Analysis: Marten et al. (2015).*
- *EIA Price Data Averaged from 2009 to 2013—Table 28 (State Price) and 34 (U.S. Electric Power Price) of* <http://www.eia.gov/coal/annual/pdf/acr.pdf>

TABLE B10. “Royalty Rate Increase (Due to Rise in the Social Cost of Methane Over Time as Estimated by Marten et al (2015)) for Surface Mining in the Powder River Basin as a Percentage of the State Price (Using EIA Methane Data)

Year	Increase in the Social Cost of Methane Relative to 2015	Royalty Rate Increase—Surface Mining in the Powder River Basin As a % of State Price
2015	0%	6.2%
2020	20%	7.5%
2025	40%	8.7%
2030	60%	10.0%
2035	80%	11.2%
2040	100%	12.5%
2045	130%	14.3%
2050	150%	15.6%

TABLE B11. Suggested Royalty Rate Increases Based on Net Methane Emission Externality Costs (EPA, 2015) by Region-Mining Type and by Geographical Scope of Price

Region-Mining Type		Royalty Rate***	
Region	Mining	State Mine-Mouth Price	Average US Price of Coal Delivered to the Electric Power Sector
Colorado	Underground	19.8%	16.9%
	Surface	2.1%	1.8%
Wyoming	Underground	56.8%	16.9%
	Surface	6.0%	1.8%
Utah	Underground	23.0%	16.9%
	Surface	2.4%	1.8%
Montana	Underground	47.6%	16.9%
	Surface	5.1%	1.8%
Powder River Basin (Wyoming)*	Underground	–	–
	Surface	6.0%	1.8%
Uinta Basin (Colorado and Utah)**	Underground	21.0%	16.9%
	Surface	2.2%	1.8%
* The basin is assigned the Wyoming price because Wyoming makes up the majority (approx. 90%) of production.			
** The basin is assigned a production-weighted price of Colorado and Utah.			
*** The middle two columns are suggested royalty rate increases: the first is the royalty rate increase if the state mine-mouth price is used and the second is the royalty rate increase if the average US price of coal delivered to power plants is used. Currently, the mine-mouth price is used to calculate royalty payments. The last column (on the right) is the suggested new royalty rate, based on state mine-mouth prices.			
**** Emissions are measured as net emissions: total methane emissions emitted during mining and from coal pores during transport, less methane captured (based on average emissions captured for each mining type).			

Sources:

- *Methane: Average Methane Emissions from 2009 to 2013 Using EPA (2015) Data: Table 3-28 of* <http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf>
- *EIA Production Data from 2005 to 2009:* http://www.eia.gov/totalenergy/data/annual/pdf/sec7_7.pdf and Table 1 of <http://www.eia.gov/coal/annual/pdf/acr.pdf>
- *Official EPA Estimate of the Social Cost of Methane Data Used in Recent EPA Cost Benefit Analysis: Marten et al. (2015)*
- *EIA Price Data Averaged from 2009 to 2013 – Table 28 (State Price) and 34 (US Electric Power Price) of* <http://www.eia.gov/coal/annual/pdf/acr.pdf>

TABLE B12. Royalty Rate Increase (Due to the Rise in Social Cost of Methane Over Time) for Surface Mining in the Powder River Basin as a Percentage of the State Price (Using EPA Methane Data)

Year	Increase in the Social Cost of Methane Relative to 2015	Royalty Rate Increase—Surface Mining in the Powder River Basin As a % of State Price
2015	0%	6.0%
2020	20%	7.2%
2025	40%	8.5%
2030	60%	9.7%
2035	80%	10.9%
2040	100%	12.1%
2045	130%	13.9%
2050	150%	15.1%

TABLE B13. Lost Government Revenue from Four Western State Coal Regions If Interior Had Used Our Suggested Royalty Rate Increases

Variable	2013	2012	2011	2010	2009	Sum
Colorado						
Underground						
Perfectly Inelastic Supply	\$100,267,220	\$124,373,414	\$122,490,754	\$117,977,881	\$121,866,135	\$586,975,404
Elasticity of 1	\$69,049,770	\$85,650,680	\$84,354,172	\$81,246,348	\$83,924,024	\$404,224,995
Elasticity of 3	\$6,614,869	\$8,205,212	\$8,081,009	\$7,783,284	\$8,039,801	\$38,724,175
Surface						
Perfectly Inelastic Supply	\$1,569,010	\$1,631,227	\$1,932,086	\$1,880,187	\$2,099,785	\$9,112,295
Elasticity of 1	\$1,114,345	\$1,158,533	\$1,372,210	\$1,335,350	\$1,491,313	\$6,471,751
Elasticity of 3	\$205,016	\$213,145	\$252,457	\$245,676	\$274,369	\$1,190,663
Wyoming						
Underground						
Perfectly Inelastic Supply	\$28,878,211	\$31,212,331	\$19,879,859	\$24,123,045	\$21,738,034	\$125,831,479
Elasticity of 1	\$8,533,494	\$9,223,225	\$5,874,486	\$7,128,345	\$6,423,576	\$37,183,125
Elasticity of 3	-\$4,066,347	-\$4,395,015	-\$2,799,287	-\$3,396,771	-\$3,060,937	-\$17,718,359
Surface						
Perfectly Inelastic Supply	\$264,881,758	\$283,844,497	\$302,442,869	\$294,487,795	\$284,529,969	\$1,430,186,888
Elasticity of 1	\$208,764,123	\$223,709,432	\$238,367,568	\$232,097,850	\$224,249,681	\$1,127,188,653
Elasticity of 3	\$96,528,854	\$103,439,301	\$110,216,965	\$107,317,958	\$103,689,103	\$521,192,182
Utah						
Underground						
Perfectly Inelastic Supply	\$89,164,712	\$90,533,373	\$106,704,259	\$93,198,583	\$118,101,387	\$497,702,314
Elasticity of 1	\$59,152,441	\$60,060,420	\$70,788,289	\$61,828,537	\$78,349,217	\$330,178,905
Elasticity of 3	-\$872,100	-\$885,487	-\$1,043,650	-\$911,554	-\$1,155,123	-\$4,867,915
Surface						
Perfectly Inelastic Supply	\$432,460	\$333,455	\$0	\$0	\$0	\$765,916
Elasticity of 1	\$358,618	\$276,518	\$0	\$0	\$0	\$635,135
Elasticity of 3	\$210,932	\$162,642	\$0	\$0	\$0	\$373,574

Source:

Share of coal mine production on public lands by states comes from

<https://www.wyden.senate.gov/download/?id=af917fa6-4e2c-4839-bc70-05d5e495b985&download=1>.

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TABLE B13. Lost Government Revenue from Four Western State Coal Regions If Interior Had Used Our Suggested Royalty Rate Increases (*continued*)

Variable	2013	2012	2011	2010	2009	Sum
Montana						
Underground						
Perfectly Inelastic Supply	\$43,663,755	\$30,707,614	\$24,911,720	\$20,661,136	\$3,328,839	\$123,273,064
Elasticity of 1	\$17,272,949	\$12,147,628	\$9,854,829	\$8,173,340	\$1,316,856	\$48,765,601
Elasticity of 3	-\$7,337,566	-\$5,160,324	-\$4,186,341	-\$3,472,043	-\$559,402	-\$20,715,676
Surface						
Perfectly Inelastic Supply	\$17,928,547	\$17,715,029	\$19,006,467	\$20,182,317	\$17,646,903	\$92,479,263
Elasticity of 1	\$14,330,728	\$14,160,058	\$15,192,336	\$16,132,222	\$14,105,603	\$73,920,947
Elasticity of 3	\$7,135,090	\$7,050,115	\$7,564,074	\$8,032,031	\$7,023,003	\$36,804,314
Total						
Underground						
Perfectly Inelastic Supply	\$261,973,898	\$276,826,733	\$273,986,591	\$255,960,644	\$265,034,396	\$1,333,782,262
Elasticity of 1	\$154,008,653	\$167,081,952	\$170,871,777	\$158,376,571	\$170,013,673	\$820,352,626
Elasticity of 3	-\$5,661,144	-\$2,235,614	\$51,730	\$2,915	\$3,264,339	-\$4,577,775
Surface						
Perfectly Inelastic Supply	\$284,811,776	\$303,524,208	\$323,381,422	\$316,550,299	\$304,276,657	\$1,532,544,362
Elasticity of 1	\$224,567,814	\$239,304,540	\$254,932,114	\$249,565,421	\$239,846,596	\$1,208,216,486
Elasticity of 3	\$104,079,892	\$110,865,204	\$118,033,497	\$115,595,665	\$110,986,476	\$559,560,734
Underground+Surface						
Perfectly Inelastic Supply	\$546,785,674	\$580,350,940	\$597,368,013	\$572,510,943	\$569,311,053	\$2,866,326,624
Elasticity of 1	\$378,576,468	\$406,386,492	\$425,803,890	\$407,941,992	\$409,860,269	\$2,028,569,112
Elasticity of 3	\$98,418,748	\$108,629,590	\$118,085,226	\$115,598,580	\$114,250,815	\$554,982,959

Source:

Share of coal mine production on public lands by states comes from

<https://www.wyden.senate.gov/download/?id=af917fa6-4e2c-4839-bc70-05d5e495b985&download=1>.

Appendix C

Measuring Option Value

There are two types of option value: real option value—also known as, Dixit-Pindyck option value—and quasi-option value—also known as Arrow-Fisher-Hanemann-Henry option value. The former option value is the full value of future flexibility—the complete value of maintaining the option to invest—while the latter is the value of future learning conditional on delaying the leasing decision. Mathematically, in a discrete investment problem, real option value is “the maximal value that can be derived from the option to invest now or later (incorporating learning) less the maximal value that can be derived from the possibility to invest now or never (Traeger, 2014).”⁸⁰ Alternatively, quasi option value is mathematically equal to the value of preservation to the decision maker who anticipates learning less the value of preservation to the decision maker who anticipates only the ability to delay his/her decision, and not learning (Traeger, 2014). The two values are related, but not identical.⁸¹

Using option values, we can define when the Department of the Interior (Interior) should delay development of a coal tract. A necessary and sufficient condition for preservation, which we will define as society being strictly better off by postponing a mining project, is

$$NPV < QOV + SOV$$

where QOV is quasi-option value of an investment, SOV is simple option value of an investment,⁸² and NPV is the expected net present value of an investment.⁸³ In other words, if the expected net present value from drilling is strictly less than the “full value of sophistication,” society is strictly better off when Interior preserves the corresponding coal tract. Alternatively, a sufficient condition for society being strictly better from preservation is that the real option value is positive: i.e.,

$$DPOV > 0.$$

where DPOV is the real option value of an investment. It is easy to see that the former condition (which includes quasi-option value) is a slight modification of the traditional net present value rule (i.e., develop if $NPOV > 0$), while the latter applies an additional condition to the traditional net present value rule.

Requirements for Option Values

The conditions for each option value to arise are irreversibility (e.g., the leasing decision and mining cannot be undone), uncertainty (e.g., uncertainty in market, environmental, and social prices and costs), and the ability to delay (e.g., Interior can postpone leasing until a future period). Additionally, quasi-option value requires the decision variable to be discrete (e.g., Interior decides whether to allow or delay mining of a coal tract). Neither option value requires risk aversion—they exist under the assumption of a risk neutral society.

Given that uncertainty is one of the key drivers of option value, Interior should be careful to consider all relevant types of uncertainty because their decisions can influence the magnitude of option value. There are multiple types of uncertainty that Interior faces when making a leasing decision for a coal tract. In terms of market uncertainty, Interior faces an uncertain price of coal, fixed cost of drilling (i.e., development costs), marginal cost of drilling (i.e., extraction costs), and quantity of coal. In so far as the government is unlikely to learn new information about the quantity of coal without exploration—which is directly associated with allowing leasing in that particular coal tract—the latter type of uncertainty

does not apply to the government leasing decision; an expected quantity of coal should be used instead. With respect to externalities, Interior faces uncertainty with respect to the fixed social cost of coal extraction (e.g., the value of externalities associated with obtaining mining rights) and the marginal social cost of coal extraction (e.g., the value of externalities associated with mining and transportation of coal). With respect to environmental and health externalities associated with mining, there are uncertainties with respect to the effect of mining on the environment and health⁸⁴ and their corresponding prices.⁸⁵ Finally, Interior also faces uncertainty with respect to the level and value of amenities from the coal tract. To the extent that this type of uncertainty can be folded into the marginal and fixed social costs of extraction, this latter type of uncertainty, like the quantity of coal, does not need to be explicitly modeled.

In previous comments to Interior on the option value associated with approving oil extraction in the intercontinental shelf (IPI, 2015), the Institute for Policy Integrity argued that Interior should explicitly model the risk of oil spills, and the option value associated with the corresponding uncertainty over the probability of spills and the magnitude of costs when an event occurs. In coal mining, there are also risks of spills—in particular a risk of spillage releases from impoundments, as discussed above. However, instead of explicitly modeling the risk of spillage from impoundments, Interior should model the expected cost of spills and the uncertainty surrounding this expected costs because: (1) spillage and impoundment is less of an issue in the PRB due to the lack of coal processing, and (2) the expected costs of spillage (in the case of coal) are small relative to the overall external cost of coal mining (whereas oil spills are the primary social cost of oil drilling). This absorption of the costs of spillage into the marginal social cost component simplifies the overall modeling.

Methodologies for Integrating Option Value into Department of the Interior's Decision Making

The option value associating with mining a particular tract of land for coal should be included in the minimum bid price for a tract of land. If Interior interprets “fair market value” narrowly, as defined in Appendix A, Interior should calculate the option value associated with uncertainty in coal and natural gas prices. This would correspond to the analysis currently conducted for offshore drilling leases done in OCS regions by Interior. If Interior interprets “fair market value” more broadly, as defined in Appendix A, Interior should also calculate the option value associated with the uncertainty in externalities. The calculated option values—regardless of the definition of “fair market value”—should be added to the minimum bid for coal tracts.

There are several well established methodologies that the agency can use to capture the full option value: contingent valuation, engineering-economic approach, or programming model. The following sections discuss each of the available methods for integrating the real option value associated with the preservation of a coal tract into Interior's leasing decisions.

Contingent Valuation. To estimate real option value or quasi-option value, Interior could use contingent valuation techniques. In particular, they could survey various regulators involved in the relevant coal-environmental planning decisions to determine the value that they place on waiting (Fisher and Hanemann, 1990; Jakobsson and Dragun, 1996).⁸⁶ Specifically, to elicit a willingness to pay estimate corresponding to quasi-option value, Fisher and Hanemann (1990) suggest asking the relevant regulator:

“What would you (as a decision maker concerned to use the resources of a site efficiently) be willing to pay for information about future benefits of preservation and development, information that would be available before you had to decide whether to preserve or develop in the future, assuming you do not foreclose the option to preserve in the future by choosing to develop now?”⁸⁷

While this question may appear difficult at first sight, the regulators responsible for natural resources leasing decisions are highly sophisticated. Given their ability to understand the question's nuances, they will likely be able to provide a comprehensive answer (Fisher and Hanemann, 1990).

Although straightforward to implement, this methodology is not ideal for use in this instance. While Interior has the welfare of U.S. citizens in mind when making its leasing decision, this methodology requires that the relevant planner optimize net social welfare in its decision making process. However, given that it is nearly impossible to prove that any agency does so, it is difficult to know if such a methodology accurately captures option value without comparing estimates from the second and third methodologies outlined below. More importantly, contingent valuation is a stated preference technique, and only provides a subjective estimate of option value. Given that the relevant planning agency (i.e., Interior) is also the agency that would be conducting the estimate, the subjectivity of the resulting estimates would be even more problematic.

Engineering Economic Approach. To estimate quasi-option value and simple option value, an “engineering-economic approach” could be applied whereby the theoretical model developed by Arrow and Fisher is parameterized using studies from the literature, additional analysis (using the available data), and surveys of experts (Fisher and Hanemann, 1990).⁸⁸ In the simplest case, Interior could develop a model with two periods and two future states. In this problem, the first period represents the current planning period (typically five years) while the second period can be interpreted as all future periods covered by a sequence of (five year) plans (Mensink and Requate, 2005).⁸⁹ The two future states represent the most likely scenarios where preservation (i.e., not developing the coal resources this period) is and is not optimal; the corresponding probabilities of each state would require specification.

Given that the simple assumptions made in our two-period, two future state model may be overly simplistic, analysts can extend the model to consider additional future states and time periods. As the dimensions of the problem increase, the use of a programming model to find a solution will become necessary. In particular, Interior could develop and parameterize a numerical (i.e., simulation) model, instead of a simple theoretical model (Mahul and Gohin, 1999, and Ha-Duong, 1998), such as they have done for the optimal stopping problem for oil drilling in the OCS with WEB2 (discussed more below). Using this new model, simulations could be run under different future scenarios (e.g. low drilling cost, high drilling cost, etc.). The agency, and the U.S. government more generally, are familiar with such scenario-based simulations.⁹⁰ Calculating quasi-option value would require only one more step in which the value of the additional information can be calculated by comparing the results of these simulations that are run under certainty to those that are run under uncertainty using the formulas established in the literature.

Choosing the engineering-economic approach has some clear advantages. The main advantage of this method is that it allows for a simple adjustment to the minimum bid price—it can be simply added to the minimum bid price to reflect the social option value of developing the tract. Furthermore, this method is objective to the extent that a reliable method can be developed to specify the values of the random parameters (the price of fossil resources and the social costs of leasing) and the corresponding probabilities using studies from the literature, available data, and surveys of experts. If some of the parameters for such a model (e.g. probabilities of various scenarios) cannot be determined, Monte Carlo simulations, which are frequently used in physical sciences and finance when there is significant uncertainty, can be used.

Optimal Stopping Model. The final approach to incorporating the real option value, as it relates to the social value of information, is to use an optimal stopping model. This is the approach taken by Interior in its hurdle price analysis

for offshore oil drilling in OCS regions, which solely considers the option value corresponding to the uncertainty of oil price. For oil drilling in OCS regions, Interior uses an in-house dynamic programming model—When Exploration Begins, version 2 (WEB2)—to conduct their hurdle price analysis. In their analysis, the hurdle price is the lowest price at which delaying development is greater than the value of exploration for the largest potential undiscovered field—the field with the highest net value per equivalent barrel. The inputs into WEB2 are the expected quantity of oil and natural gas,⁹¹ costs,⁹² and prices.⁹³ (BOEM, 2012).

In using a hurdle price analysis, the agency only accounts for the real option value as it relates to market price uncertainty. Thus, they exclude market uncertainty as it relates to the market costs of drilling (e.g., exploration, development, and extraction)⁹⁴ and the social costs of drilling (e.g., environmental, infrastructure, and catastrophic oil spills). By ignoring the possibility of acquiring further information about the consequences of a development action on the environment,⁹⁵ Interior inevitably underestimates the net benefits of delaying the leasing of the land for resource extraction and initiates leases prematurely. While Policy Integrity in no way advocates that the hurdle price is the best methodology, if Interior chooses to use an optimal stopping model, a social hurdle price should be calculated by modifying the agency's dynamic programming model (WEB2) to include externalities of drilling and the corresponding uncertainty underlying them and market costs.⁹⁶ Similarly, an optimal stopping model developed for coal mining—specifically to estimate option value corresponding to coal leases to augment minimum bid prices—should also account for the uncertainties of externalities and extraction costs in addition to the uncertainty in coal prices.

The main advantage of this estimation strategy is it provides a clear method to estimate the stochastic processes underlying uncertain price and cost variables. In actual application, long time series data exists for only some random variables, such as oil, gas, and coal prices, to estimate the parameters of the stochastic processes and to test between the alternative processes proposed in the literature.⁹⁷ In the case of market cost and externality cost data, there may be only short time-series data or no data available; this is particularly true for regional data pertaining to particular coal tracts that have not undergone leasing. In some cases, data for related process made be available to estimate the stochastic process.⁹⁸ If data are unavailable, experts can be surveyed to parameterize the model. When short-time series data or expert opinions are used, the use of sensitivity analysis over the assumed stochastic processes and Monte Carlos simulations over the parameters is suggested.

Appendix D

Integrating Externalities and Option Value into Minimum Bid and Royalty Rates

To summarize, the Department of the Interior must obtain at least fair market value for the development of fossil fuels—including coal and natural gas—on public lands. If we interpret “fair market value” narrowly, we can interpret this as the market price of all fossil resources—coal and natural gas—on the land. This narrow interpretation implies that option values (corresponding to commodity prices and market costs, only) should be added to the minimum bids for coal tract leases, while the value of natural gas should be added to royalty rates. If we interpret “fair market value” more broadly, we can interpret this as maximizing the social return of mining; this includes the fair market price of fossil fuel resources—e.g., coal and natural gas—and the social cost of mining—i.e., the cost to American consumers of mining on public lands due to non-internalized externalities. This broad interpretation implies that fixed social costs and option values (corresponding to commodity prices, market costs, and social costs) should be added to the minimum bids and internal fair market calculations for coal tract leases, while the value of natural gas resources and variable social costs should be added to royalty rates.

There are several additional issues that should be addressed when integrating these values into minimum bid prices and royalty rates. Each of these issues are discussed in the report, but reviewed here.

Ensuring a fair market price of coal

To calculate the adjustment to royalty rates for externalities—when utilizing the broadest definition—it is essential to define market price. This is because royalty rates are determined as a share of this price. As argued above this fair market price should be either (1) the sales price of coal to power plants (i.e., the total value of upstream production), or (2) the sale price of coal to power plants less the cost of transportation (i.e., the total revenue from producing coal realized by the coal mine). Using this price, the adjustment to the royalty rate for coal equals the external variable cost of producing coal on public lands divided by the fair market price of coal. If an alternative price is realized (i.e., a lower price is used based on sales at an earlier stage in the production process), the adjustment to the royalty rate should instead be the external variable cost of producing coal on public land divided by this realized price.

Leakage

Increasing the minimum bid and royalty rates on public coal lands may result in leakage. This leakage is likely to take the form of shifting coal production to private lands—particularly the Eastern United States—or increasing demand for other fossil fuels (oil and natural gas), biofuels, or renewables (wind and solar) on public and private lands; the externalities from these alternative energy sources may be higher or lower than the production of coal on public lands. With regards to shifting to other energy sources on public lands, the U.S. government should also account for their upstream externalities when determining their minimum bidding prices and royalty rates instead of adjusting the minimum bids and royalty rates of coal to account for this type of leakage. Given that coal has one of the highest levels of externalities according to most lifecycle analyses and that agencies do not consider modifying the minimum bids and royalty rates of all public

resources simultaneously, coal is a reasonable resource with which to start this update in bid prices and royalty rates. To the extent that production shifts to private lands where externalities are unaccounted for in land values and production decisions, minimum bids and royalty rates should be adjusted accordingly. In order to do this, a study on the leakage rates must be conducted. We believe that the leakage rate to private coal will be relatively limited due to the lower production costs and sulfur content (which is regulated under the Clean Air Act) of Western coal (UCS, 2015).

Next Best Use

In our analysis above, we implicitly assume that the next best use is non-commercial use (i.e., open public space). In some cases, this may not be true—such as if the land is leased for cattle ranching. While these alternative uses may produce externalities—i.e., cattle produce methane—this is best dealt with by charging these alternative uses higher minimum bid prices and royalty rates (or lease rates) to account for their externalities, rather than attempting to adjust the minimum bid price and royalty rates of coal to account for alternative uses; this is consistent with our view on how to address leakage to other energy resources on public lands, discussed in the previous paragraph. Otherwise, the agency is faced with determining what it believes to be the next best use, as well as complicated valuation questions (e.g., determining whether the cattle ranch would exist in an alternate location if the mining rights are granted).

Adjusting For Externality Reduction Measures

Ideally coal mining companies would reduce their externalities through changing their production methods or investing in technologies. If such investments are made, the royalty rates should be adjusted downwards to account for this reduction in externalities. The most likely example of this type of investment by coal companies is investment in methane capture technologies. To incentivize such an investment, royalty rates should be reduced to reflect the decrease in methane emissions due to this capture. If such reductions are allowed by Interior, the agency should use the average cost of gross methane emissions instead of the average costs of net methane emissions.⁹⁹

Present Value Calculation for the Minimum Bid

The minimum bid is a one-time price paid by the coal company for the mining rights on a particular tract of land. Given its one time nature, all fixed external costs should be adjusted to their present value. Then, the adjustment to the minimum bid price is the sum of the present value of natural gas resources, the present value of fixed external costs, and option value corresponding to the uncertainty in coal prices, natural gas prices, and the value of externalities.

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Appendix Endnotes

- ¹ Lee et al. (1995) argue that occupational hazards are not fully compensated for by wages, though they believe that there is insufficient evidence of what that share may be. Similarly, while Epstein et al (2011) do not quantify the value of these hazards, they support a similar argument in their statement that worker “deaths and illnesses are reflected in wages and workers’ comp, costs considered internal to the coal industry, but long-term support often depends on state and federal funds.” Others disagree, such as NRC (2010), by clearly stating that traditionally, workplace injuries and death are not considered an externality.
- ² According to Epstein et al (2011), unfunded Abandoned Mine Land projects since the passing of the Surface Mine Control and Reclamation Act in 1977 to the end 2007 totaled to \$8.8 billion. Given that only \$7.4 million had been collected between 1978 and the end of 2005, up to 54% (approximately 50%) of reclamation projects were unfunded in 2007.
- ³ Land reclamation releases additional GHG emissions in the process (Odeh and Cockerill, 2008; Spath et al., 1999)
- ⁴ Instead of adjusting the minimum bid, the rental rate—the annual payment made by the mining company when mining has not begun—can be set to account for the social fixed cost of lost public access during this pre-mining period. If the rental rate is adjusted in this way, the minimum bid must still be adjusted to account for the social fixed costs of mining in the post mining period—i.e., ALL lost public amenities from when mining begins until reclamation and the public cost of reclamation.
- ⁵ There are several estimates in the literature of the percentage of CO₂e emissions from methane leakage relative to total upstream and downstream GHG emissions from coal: Spath et al (1999) estimates it at 1.9% for the US; Hondo (2005) estimates it to be 5.4% for Japan; and Odeh and Cockerill (2008) put this percentage higher at 6.5% for South Africa.
- ⁶ This was up from 71 million tons of CO₂e in 2007 (Epstein et al., 2011).
- ⁷ Using the currently accepted GWP of 34 (IPCC, 2013. Pages 713 to 714), methane emissions from coal mines was actually 117 million metric tons CO₂e of methane with an emission rate of 0.12 metric tons of CO₂e per metric ton of coal.
- ⁸ The EPA (2015) estimates a significantly lower GHG emissions level than EIA (2011) in 2009 at 70.7 million megatons from mining.
- ⁹ Spath et al (1999, page 21) cites a study of 1.91 grams of methane emissions for a kilogram of received coal from surface mining in Illinois versus 4.23 g from underground mining. Spath et al (1999) also conducted sensitivity analysis changing these numbers to 0.84 and 9.21, respectively. In 2009, the EPA (2015) estimates coal mine capture to be 19.6 million megatonnes—approximately 25% of total emissions—from underground mining; this percentage increased to approximately 30% by 2013.
- ¹⁰ For surface coal mines, Spath et al (1999) estimates are based on the assumption that annual electricity and fuel (and oil) demands are 14,300 MWh and 269 m3 per MM tonne of coal mined.
- ¹¹ There are alternative estimates in the literature of the percentage of CO₂e emissions from non-methane leakage in mining: Hondo (2005) estimates it to be 1% for Japan and Odeh and Cockerill (2008) estimate it to be 0.8% for South Africa.
- ¹² Appendix B of Spath et al (1999) documents the various types of air pollutants from the lifecycle of coal, including emissions from surface mining.
- ¹³ Epstein (2011) cites a 2008 study that provides new evidence that coal mining significantly increases toxins and heavy metals—including arsenic—in waterways surrounding mines.
- ¹⁴ Approximately half of the water pollution comes from mining according to Spath et al. (1999, pages 40 and 45), and the remaining half was attributed to the power generation subsystem (i.e., downstream).
- ¹⁵ Underground minds can also increase acidity of surrounding water ways (NRC, 2010).
- ¹⁶ There is evidence that increased mining decreases fish populations (Lee et al., 1995). In Wyoming, this could potentially have an economic effect through decreased tourism. A portion of external cost of water pollution could be captured using the travel cost method to estimate the cost of loss tourism from decreased fishing stocks from mining (Lee et al., 1995).

- ¹⁷ Groundwater water is a common resource—and as such suffers from a tragedy of the commons (Feeny et al, 1990). There is some evidence that mining is leading to the draining of some aquifers that are used for alternative uses: drinking and livestock (<http://www.powderriverbasin.org/assets/Uploads/files/coal-mining/PRB-coal-fact-sheet.pdf>).
- ¹⁸ Slurry pipelines transport coal slurry—a mixture of coal and water (UCS, 2015).
- ¹⁹ 98% of Wyoming coal is destined for power plants (EIA, 2015).
- ²⁰ NRC (2010) computes this estimate “by multiplying the total number of occupational and public injuries occurring on freight railroads¹⁶ in 2007 by the proportion of ton-miles of commercial freight activity on domestic railroads accounted for by coal (43%). This estimate is then multiplied by the percent of coal transported that is used for electric power generation (91%).” We ignore this latter step because we are interested in all coal.
- ²¹ Adjusting the EPA’s recommended VSL of 7.4 million in 2006 for inflation (an inflation factor of 1.17 according to the US government’s CPI calculator), the cost to society of these impacts are approximately \$2.2 billion in 2014 dollars.
- ²² In the United States, SO₂ is regulated using a tradable permit market. As a consequence, sulfur dioxide should not be considered an externality from train emissions because a decrease in their emissions from trains will merely result in an increase in another US sector of the economy (Krupnick and Burtraw, 1996).
- ²³ Appendix B in Spath et al (1999) documents the various types of air pollutants from the lifecycle of coal, including from transportation.
- ²⁴ There are alternative estimates in the literature of the percentage of CO₂e emissions from coal transportation: Hondo (2005) estimates it to be 1.6% for Japan and Odeh and Cockerill (2008) estimate it to be 3.5% (including some additional sources) for South Africa.
- ²⁵ Additional states that produce coal include: West Virginia, Kentucky, Pennsylvania, Illinois, Texas, Montana, Indiana, North Dakota, Ohio, Colorado, New Mexico, Alabama, Utah, Virginia, Arizona, Mississippi, Louisiana, Maryland, Alaska, Oklahoma, Tennessee, Missouri, Arkansas, and Kansas (EIA, 2015).
- ²⁶ 39% of coal was mined in Wyoming in 2013 compared to 41% of coal came from East of the Mississippi including West Virginia (11%), Kentucky (8%), and Pennsylvania (5%) where underground mining is more common (<http://www.eia.gov/coal/data.cfm>).
- ²⁷ At a minimum, BLM should qualitative consider these additional costs if they use this average cost estimate of mining on U.S. public lands in leasing decisions that consider different locations and mining methods than strip mining in the PRB.
- ²⁸ For surface coal mining, Spath et al (1999) assumes annual emissions of ammonia nitrate of 2,070 Mg per MM tonne of coal mined.
- ²⁹ Epstein et al (2011) specified 6 million metric tons of CO₂e from loss of forests as a lower and best estimate of additional GHG emissions from mountaintop removal, and 37 million metric tons as an upper bound estimate.
- ³⁰ Theoretically, some portion of this cost could be internalized through insurance payments and other means. While it is difficult to determine what portion, it is clearly less than 100% (Berry et al., 1995).
- ³¹ According to Epstein et al (2011), mountaintop removal results in the loss of aquatic species some of which have yet to be identified.
- ³² East of the Mississippi, 14% of coal is shipped by truck, 46% by rail, 35% by water, and 4% using other methods. West of the Mississippi, 10% of coal is shipped by truck, 80% by rail, 0% by water, and 10% by other methods [EIA, 2015 April]. Coal mines are even less reliant on freight trucks—only 0.3% of Wyoming coal is shipping by truck (EIA, 2015). In general, trucks are generally used to move coal for shorter distances (Lee et al., 1995).
- ³³ The wear and tear of private roads—such as at the coal mining site—should not be included as an externality because they are built and maintained by the mining company (Krupnick and Burtraw, 1996). Additionally, some portion of wear and tear on private roads is partially internalized through fees (Krupnick and Burtraw, 1996); this portion should also not be included as an externality.
- ³⁴ This step includes determining all externalities from coal production and use, and then prioritizing those that are significant and that can be measured and valued (Berry et al., 1998).
- ³⁵ Lee et al (1995) focuses on lifecycle costs—including the upstream costs of mining, processing, and transportation—of seven fuels for a hypothetical power plant built in 1990. The locations of their hypothetical coal plants are Eastern Tennessee and Northwestern New Mexico—the former

being more densely populated than the latter (Burtraw and Krupnick, 2012).

³⁶ A report for New York state that estimated the external cost of pollution from various new and existing electric resource options in three NY state locations (urban, suburban, and rural) using the damage function approach.

³⁷ ExternE focuses on estimating the external costs of new and existing power plants—including coal—in representative European sites.

³⁸ NRC (2010) studies the upstream and downstream externalities of the U.S. coal fuel cycle. Most upstream are qualitatively studied, while some air pollution emissions are quantified and the costs of health impacts from transporting coal are estimated.

³⁹ Epstein et al (2011) estimates the upstream and downstream external costs of U.S. coal.

⁴⁰ Spath et al (1999) estimates the non-monetary impacts of coal in a lifecycle analysis of an average U.S. coal-fired power plants assuming two different types of mining (surface and underground) and three different forms of transportation (railroad, water, and trucks).

⁴¹ Odeh and Cockerill (2008) is a quantitative analysis of the upstream and downstream impacts—particularly focusing on GHG emissions—of UK coal power plants.

⁴² Nkambule and Blignaut (2012) estimate the upstream externalities for the Kusile coal-fired power station—a proposed coal fired power plant in South Africa.

⁴³ Burtraw et al. (2012) emphasize the superiority of the damage cost approach over the abatement cost approach. For application of the damage function approach, a specific location should be specified (Berry et al., 1995).

⁴⁴ In cases where this is not true, we will emphasize the discrepancy.

⁴⁵ While Epstein et al (2011) is the only published article of the recommended studies, Krupnick and Burtraw (1996) emphasize that the earliest three recommended models are comprehensive and peer-reviewed.

⁴⁶ Nkambule and Blignaut (2012) account for lost ecosystem services (only carbon storage) and agricultural production from land conversion due to the mine. The loss of agricultural production—specifically maize production—is the third highest cost in the study. However, the South African study is irrelevant with respect to lost amenities in Wyoming's PRB.

⁴⁷ For example, Berry et al (1998) assume that GHG emissions from their UK reference site are 300 g/GJ.

⁴⁸ The Interagency Working Group on the Social Cost of Carbon (2010; 2013; 2015) produces four social cost of carbon estimates using three different discount rates. The current social cost of carbon pollution estimates for a unit of emissions in 2015 are \$56, \$36, and \$11 (2007 USD) using discount rates of 2.5 percent, 3 percent, and 5 percent, respectively. The fourth social cost of carbon pollution estimate of \$109 corresponds to the 95th-percentile of the SCC distribution corresponding to the 3% discount rate in an attempt to capture the damages associated with extreme climatic outcomes. The estimate of \$36, which uses a 3 percent discount rate, is considered the “central” or best estimate for a unit of emissions in 2015. We specify the possible range of SCC values using \$11 and \$109 to calculate the low and high estimates following the recommendations of the IWG (2010) recommendations.

Using a consistent methodology, Marten et al. (2015) estimates a social cost of methane of \$450, \$1,000, and \$1,400 per metric ton of methane (2007 USD) using discount rates of 2.5 percent, 3 percent, and 5 percent and \$2,800 per metric ton of carbon using a 3% discount rate and the 95th percentile value. We use \$1000/metric ton of methane as the central (i.e., “best”) estimate, and the \$450 and \$2,800 estimates to specify the complete range of costs.

⁴⁹ Using EPA (2015) data, we estimate the range of the average cost of methane emissions from 2009 to 2013 to be \$0.43 to \$2.65 per metric ton of coal mined with a most likely value of \$0.95.

⁵⁰ Technically, they are the cost of 2007 emissions if they were omitted in 2015. We use the 2015 SC to make the estimates more current, and use the 2007 average amount of methane per ton of coal as a proxy for average emissions in 2015.

⁵¹ These estimates include impacts from nitrogen oxides, Sulphur dioxide, and particulate matter (PM_{2.5}). Due to existing regulations that cap Sulphur dioxide emissions in the United States, only nitrogen oxides and particulate matter apply in the PRB.

⁵² Given the difficulty of valuing ecosystems, it is unsurprising that only three of the recommended models consider the value of ecosystems (Burtraw et al., 2012) and mostly qualitatively. To capture the full value of ecosystems—including the value of biodiversity and non-use values—stated preference methods are necessary (Berry et al., 1995).

Specifically, Rowe et al (1995) find an external cost of water equal to 0.022 mills/kWh from upstream and downstream pollution. This is compares to an external cost of air pollution of 71.555 mills/kWh.

Mathematically, the conversion is $Total Cost_{j, Total Freight, US} = ton - miles_{Total Freight, US} * Cost Per Ton - Mile_{j, Total Freight, US}$ where $Total Cost_{j, Total Freight, US}$ is the total cost of externality j from U.S. freight trains; $Cost Per Ton - Mile_{j, Total Freight, US}$ is the cost per ton mile of externality j from U.S. freight trains; and $ton - miles_{Total Freight, US}$ is total ton-miles of U.S. freight trains, which is equal 1.6812 trillion averaged from 1999 to 2003 using AAR (2011-2015) data.

According to U.S. DOT (2012, Tables 1 and 7), 44% of freight train tonnage was coal. According to AAR (2011-2014), the range of coal ranged from 39% to 43% from 2011 averaging to slightly above 40%.

According to NRC (2011), 43% of freight train ton-miles were coal in 2002. According to U.S. DOT (2012), 50% of freight train ton-miles were coal in 2012.

This conversion method is based on Lee et al.'s (1995) recommended method for converting total mortality costs of US freight trains to the total mortality costs of U.S. coal freight trains. Mathematically, Lee et al.'s (1995) conversion equation is

$$Total Cost_{Fatalities, Coal, US} = Total Cost_{Fatalities, Total Freight, US} * \left(\frac{train - miles_{Coal, US}}{train - miles_{Total Freight, US}} \right)$$

where $Total Cost_{j,k,US}$ is the total cost of externality j in transporting production from US sector k to market and train-miles (i.e., $train - miles_k$) is their proxy for risk for endpoint j . NRC (2010) uses a similar calculation method, but specifies ton-miles (i.e., $ton - miles_k$) as their proxy for risk. Following, NRC (2010), we assume that

$$Total Cost_{j, Coal, US} = Total Cost_{j, Total Freight, US} * \left(\frac{ton - miles_{Coal, US}}{ton - miles_{Total Freight, US}} \right)$$

where $\frac{ton - miles_{Coal}}{ton - miles_{Total Freight}} = 0.45$.

Mathematically, we add an additional adjustment of

$$\left(\frac{ton - miles_{Coal, Wyoming}}{ton - miles_{Coal, US}} \right)$$

= 0.8 to convert the total cost of externality j from transporting U.S. coal to the total cost of externality j from transporting Wyoming's (Powder River Basin's) coal to market.

Mathematically, we divide by total coal production (in metric tons) in Wyoming (i.e., $Output_{k, Wyoming}$) to calculate average cost; specifically, we divide by average production from 2009 to 2013 (EIA, 2002 to 2012).

Mathematically, our final calculation is

$$Avg Cost_{j, Coal, Wyoming} = \frac{\left(\frac{ton - miles_{Coal, US}}{ton - miles_{Total Freight, US}} \right) \left(\frac{ton - miles_{Coal, Wyoming}}{ton - miles_{Coal, US}} \right) * Output_{k, Wyoming}}{(ton - miles_{Total Freight, US} * Cost Per Ton - Mile_{j, Total Freight, US})}$$

For trains, Spath et al (1999, p. 22) assumes that the average transportation distance by rail is 483 km with a longest distance travelled being 1,538 km. They also assume 48 km of train transport when coal is moved by barge.

We calculate the travel distance and ton-miles of coal using EIA (2015) data. To make these calculations, we assumed rail distances between states were approximately equal to driving distance on google map between the sending and receiving states' largest cities. For within state transportation, we assumed that travel distances were equal to the minimum inter-state travel distance—33 miles between Pennsylvania and Delaware.

Forkenbrock (2001) estimates an external cost of climate change damages from U.S. freight trains to be \$0.0002/ton-miles (1994 USD) using an SCC of \$10 per metric ton of CO₂. In addition to citing Forkenbrock (2001), Delucchi and McCubbin (2010) calculate a range of \$0.00006 to \$0.0047 per ton-miles of U.S. rail freight (2006 USD) using SCC estimates of \$0.91/metric ton to \$73/metric ton; this range is cited by GAO (2011). Finally, Austin (2015) estimates a range of \$0.00007 to \$0.0024 mile-tons of U.S. rail freight (2014 USD) with a central estimate of \$0.0005 per mile tone using the 5th, 50th, and the 95th percentiles of the social cost of carbon distribution estimated by the IWG (2013) using a 3% discount rate.

Given that the AAR (2015) data is drawn from EPA (2015), it is unsurprising that the two data sets are consistent. Specifically, AAR (2015) lists 47.5 million metric tons of CO₂e from rail (41.8 million from freight and 5.7 million from passenger). Similarly, EPA (2015, Table 2-13) lists 47.5 million metric tons of CO₂e from rail in 2013.

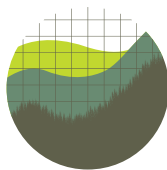
See supra, note 48.

According to EPA (2008b), NOX, PM10, and VOC emissions are predicted to decline by 17%, 39%, and 31%, respectively, from 2006 to 2015. We assume a range of 17% to 39% when calculating possible declines.

- ⁶⁷ Zhang et al. (2004) is the upper boundary estimate from Delucchi and McCubbin (2010), but it is not cited here because it pertains to Canada and not the United States.
- ⁶⁸ These estimates are based on cost estimates from Matthews et al (2001), which relies on an input-output model of the United States.
- ⁶⁹ Assuming that 45% of freight is coal, an approximate cost of air pollution from U.S. coal transport is \$14 per ton of coal in 2015 USD. It is unclear if this is an overestimate or an underestimate. On the one hand, coal shipping from Wyoming travels a much farther distance than average U.S. freight. If we adjust this estimate to account for the fact that Wyoming coal represents 80% of U.S. coal's ton-miles by rail, we find that the average cost of air pollution from transportation per ton of Wyoming coal is approximately \$28. On the one hand, these estimates are dated given EPA's 2008 rule to clean up diesel pollution from trains starting in 2015 (though they only impact new engines built in 2015 or later)—that are predicted to reduce PM by up to 90% and NOX by up to 80% in the long-run. Adjusting the 2006 cost estimates for predicted reductions of 9.55% (NOX) and 13.84% (PM 2.5) due to this EPA (2008a) rule produces a final estimate is \$25 per metric ton of Wyoming coal extracted in 2015.
- ⁷⁰ Lee et al (1995) calculates the public fatalities externality cost for two hypothetical power plants. For their hypothetical plant (that uses approximate 1.36 million tons of coal) in the Southeastern United States with an average travel distance of 410 miles, a VSL of \$3.5 million, a VSI (a measure of the willingness to pay to avoid non-fatal injuries) of approximately \$25,000, and an internalization rate of 4.7%, the external cost of public mortality and morbidity from coal trains is approximately \$1 per ton.
- ⁷¹ This latter assumption is essential because all authors use either freight train miles or ton-miles as their proxy for risk.
- ⁷² Citing the NRC (2010) numbers in their study, Epstein et al (2011) argues NRC (2010) uses the share of revenue-ton-miles instead of ton-miles as their proxy for risk.
- ⁷³ Assuming that "\$165 million is paid out by the freight industry in claims and suits to the public each year", they estimate that approximately 4.7% of total damages is internalized by coal companies.
- ⁷⁴ We also increase the share of coal from 43% to 45% to be consistent with our other estimates.
- ⁷⁵ With respect to the noise externality of trains, ExternE uses a sound dispersion model to estimate noise impacts, and draws monetary values of damages from a meta-analysis of the hedonic price literature. In Berry et al (1998)—a study estimating the external cost of theoretical power plants in England using ExternE—the estimates of the cost of noise are 0.13 mECU/kWh and 0.024 mECU/kWh for both power station and transport noise, respectively. Given that Berry et al. (1998) argues that the cost is small and the dispersion model tends to over-estimate impacts, noise is unlikely to be a major source of upstream externality costs of coal mining.
- ⁷⁶ We assume an average elasticity of supply of between 1 and 3 (based on EIA's chosen elasticity of supply for U.S. coal (Haggerty et al., 2015)); this results in estimated lost revenue of between \$600 million and \$1.2 billion from 2009 through 2013. Regional supply elasticity in the Powder River Basin may be more inelastic (lower), making the upper limit on lost revenue about \$1.6 billion.
- ⁷⁷ This value assumes that there is no leakage to non-federal areas in the United States.
- ⁷⁸ As in the PRB example, we assume an average elasticity of supply of between 1 and 3 (based on EIA's chosen elasticity of supply for U.S. coal (Haggerty et al., 2015)); this results in estimated lost revenue of between \$550 million and \$2 billion, from 2009 through 2013. Regional supply elasticity in the Powder River Basin may be more inelastic (lower), making the upper limit on lost revenue about \$2.9 billion.
- ⁷⁹ Implicitly, we assume in these calculations that real (i.e., accounting for inflation) U.S. coal prices remain constant at their 2009 to 2013 average.
- ⁸⁰ See equation (5) in Traeger (2014).
- ⁸¹ See Traeger (2014) and Mensink and Requate (205).
- ⁸² While quasi-option value is the "the value of learning under postponement" defined above, simple option value is "the value of the option to carry out the project in the second period, conditional on not carrying out the project in the first period, in the absence of information flow (Traeger, 2014)."
- ⁸³ See equation (9) in Traeger (2014).
- ⁸⁴ In many cases, the modeling of mining impacts take various steps from emission of impacts take various steps. For example, the effect of emission on crop yields require: (1) the modeling of key emissions from mining (i.e., the emission factors), the modeling of emission pollution formation and dispersion (i.e., models of atmospheric transport and chemistry), modeling of crop growth, and a model of yield change (i.e., a dose response function) (Berry et al., 1995). Similarly, the effects of air and water pollution on health and

the environment require at a minimum: (1) emission factors, dispersion models, and dose-response functions. At each of these steps, there is uncertainty.

- ⁸⁵ The prices of impacts are captured through prices estimates (e.g., the social cost of carbon or the value of statistical life) or impact equations. Like the physical effects of drilling, prices are uncertain. While we may learn the effects of drilling (i.e. learn what state of the world we are in), we are unlikely to learn the price of the environmental services. Instead, as more estimates become available, the distribution of estimates will potentially center on a particular value; this should be thought of the variance of a meta-analysis declining over time as more points become available, and should not be thought of as uncertainty surrounding a point estimate which will always be there.
- ⁸⁶ According to Jakobsson and Dragun (1996), “Option price [real option value plus consumer surplus] can be determined using surveys.”
- ⁸⁷ Similarly, decision makers could be elicited for willingness to accept estimates.
- ⁸⁸ Examples include Fisher and Hanemann (1990), Albers and Robinson (2007), Adger et al. (1994), and Tegene et al. (1999).
- ⁸⁹ Under this interpretation, the second period value function represents the expected present value of all future net benefits from the optimal leasing decision.
- ⁹⁰ See BOEM (2012) and the recently released White House (2014).
- ⁹¹ To estimate the quantity of oil, Interior uses “field counts at various levels of uncertainty (BOEM, 2012).” Based on this analysis, the DOI’s hurdle price analysis uses supply estimates for “the mean probability, an accepted and unbiased statistical approach in the presence of uncertainty (BOEM, 2012).”
- ⁹² The cost inputs are from the commercial FieldPlan and MAG-Plan, and may not include externality cost estimates.
- ⁹³ By using the price model specified in WEB2, DOI assumes the oil price follows a mean reversion process. Presumably Interior estimated the mean-reversion parameters using oil price data.
- ⁹⁴ “Once the largest field size is set, the WEB2 model requires estimates of costs associated with that field. Cost inputs for the WEB2 model came from the commercial Que\$tor cost modeling system and from data collected by BOEM for the socioeconomic analysis of the Five-Year Program (i.e., the economic impact model MAG-PLAN). The Que\$tor software allows BOEM to calculate the expected costs of developments, specifically for the size of the largest geologic field in the planning area (BOEM, 2015).”
- ⁹⁵ For example, as more data on the environmental effects of drilling become available (i.e. as we learn more about the state of the world we live in), the uncertainty surrounding the net social benefits of drilling would be less, leading to more precise environmental damage estimates. The additional value of this information—also known as quasi-option value—is always nonnegative (Fisher and Hanemann, 1990).
- ⁹⁶ A possible starting point could be Conrad and Kotani (2005).
- ⁹⁷ As demonstrated in Conrad and Kotani (2005) and Fackler (2007), the resulting option value estimate depends on the assumed stochastic process(es).
- ⁹⁸ For example, in the forestry literature, the value of forest amenities is unobservable. By assuming that visitation rates to the forests are proportional to the level of amenities, Conrad (1997) demonstrates that visitation rates and amenities are governed by identical stochastic processes. This allows Conrad (1997) and Forsyth (2000) to estimate parameters in the stochastic process governing forest amenities using availability visitation data.
- ⁹⁹ Currently (i.e., in Appendix B), we calculate the average cost of net methane in the United States, which equals the product of the social cost of methane (currently calculated in this paper as the product of the SCC and the global warming potential of methane) and U.S. net methane emissions (U.S. gross methane emission less U.S. methane capture) divided by total U.S. coal production. If we make a reduction in royalty rates due to methane capture, the appropriate average cost of methane calculation is the average cost of gross methane emissions, which equals the product of the social cost of methane and U.S. gross methane emissions of methane divided by total U.S. coal production.



Institute *for*
Policy Integrity

NEW YORK UNIVERSITY SCHOOL OF LAW

Institute for Policy Integrity
New York University School of Law
Wilf Hall, 139 MacDougal Street, New York, New York 10012
policyintegrity.org