Policy Brief

A Significant Threat to Coal Exports from the Powder River Basin: The Proposed Default Provision for Federal Coal Royalties

by

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Executive Summary

How should coal on federal lands be valued? Are taxpayers getting a reasonable return on America's natural resources? The Office of Natural Resource Revenue (ONRR) in the U.S. Department of the Interior is re-visiting these questions with proposed changes to the rules for determining royalties collected from mining coal on federal lands.

This study finds that the proposed changes would make exports of coal mined from federal lands unprofitable, because a provision buried within the proposed rule would extend unparalleled and unrestricted power to the Secretary of the Interior. Under this 'default provision,' the Secretary would be granted unrestricted authority to assign a "reasonable" value to coal mined on federal lands for determining royalty payments. Instead of benefiting from this proposed change, American taxpayers would likely receive less in royalty revenue because production to support coal exports would likely not occur under this provision.

Most federal coal comes from the Powder River Basin (PRB) in Wyoming and Montana. With the prospect of declining domestic coal consumption, many PRB coal producers are hoping to export this coal to U.S. allies in East Asia such as South Korea, Japan, and Taiwan. The proposed rule changes, however, will likely dash these expectations and cost the federal government, Wyoming, and Montana significant royalty revenue.

The reason is that the proposed rules create a great deal of uncertainty and, thereby, a significant increase in the transaction costs associated with producing and marketing coal. The source of this uncertainty is the proposed default provision that would allow ONRR the discretion to set federal coal royalties on a case-by-case basis using a variety of discretionary factors rather than using standard valuation methods.

A variety of studies, reviewed in this paper, argue that federal coal royalties are too low--either because transportation costs should be disallowed or that carbon fees should be imposed. Since the default provision provides essentially an open door for these arguments to be used to revalue federal coal, coal companies would be required to set aside funds between the time coal export sales occur and when royalties are audited, often a lag of some six to eight years. As a result, the proposed default provision would raise coal transaction costs and, thereby, impose a risk premium on investments to build new coal export capacity.

While future demand projections suggest long-term profitability, coal exports from the PRB are currently not profitable due to low international coal prices. The proposed rule changes, therefore, make a tough situation even more challenging as, additional transaction costs arising from the uncertainty created by the default provision are incurred.

The proposed rule changes would most likely eliminate any profit margin on PRB coal exports to Asia. An illustration of the possible effects and uncertainties associated the proposed rule changes on profits for coal export sales are provided in Figure ES1. Under the proposed netback policy, profits on coal exports are -\$0.04, or essentially zero.

Any recovery of international coal prices would likely restore the profitably of coal exports and revive incentives to export PRB coal. The proposed rule changes, however, make this prospect less likely. For instance, if a 50% transport cost cap is implemented, profits on coal exports from the PRB sink to -$4.14. If a carbon fee were erroneously assessed, profits on coal export sales would be -$26 per ton, which would clearly render any coal exports from the PRB uneconomic. The criteria for setting coal royalties under the default provision, however, are not defined and, therefore, expected profits from future PRB coal exports would not be known under the proposed default provision. This uncertainty entails real financial costs that firms must bear in the interim between infrastructure development and future coal export sales. These additional transaction costs arising from uncertainty would reduce these expected profits even further from those estimated below.

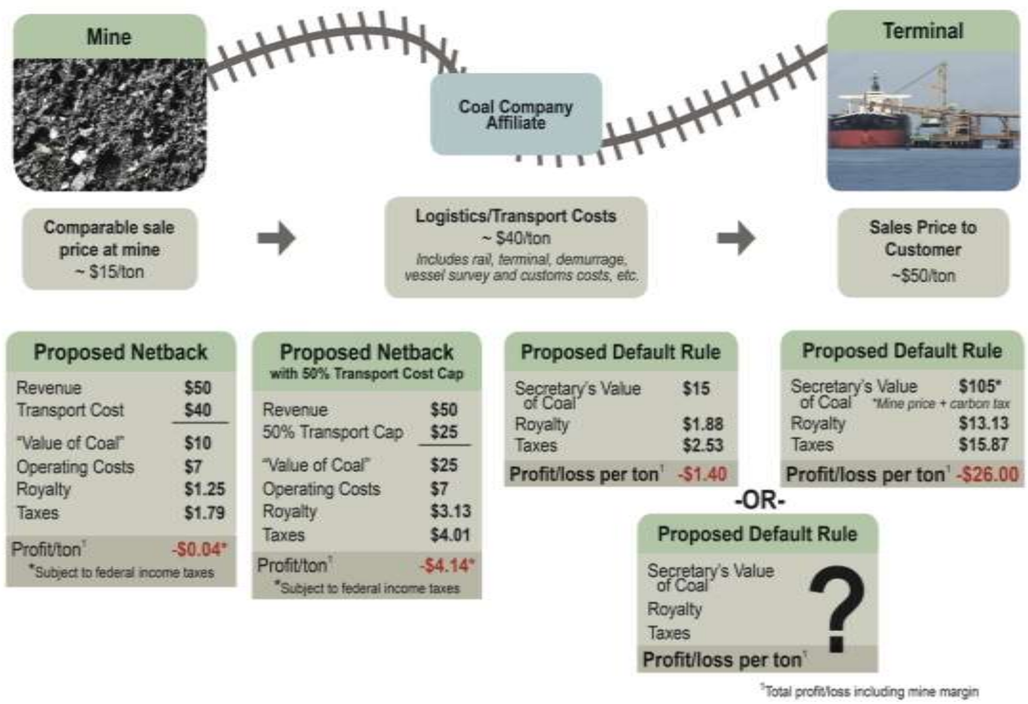

Figure ES1: Possible Impacts on Coal Export Profitability

The proposed default provision would force coal companies to carry significant financial liabilities to protect their shareholders from unilateral royalty re-valuation by ONRR. These transactions costs would likely force firms to re-organize their operations to spin-off coal marketing affiliates and to abandon efforts reaching existing or new customers abroad for PRB coal. The proposed default provision, therefore, is a bad idea and should not be adopted.

If enacted, the default provision would likely shutdown efforts to export PRB coal and eventually lead to a loss of over $200 million in federal coal royalties. If federal coal royalties need reform, they should be pegged to well-known price indices for PRB coal.

I. Introduction

The Obama Administration recently proposed changing regulations that determine royalty payments by coal companies to the federal government for mining coal on federal and Indian lands. Coal supplies roughly 40-percent of the electricity supply in the U.S. and coal mined on federal lands, primarily from the Powder River Basin (PRB) in Wyoming and Montana, provides about half of the nation's coal. If implemented, these regulatory changes could significantly raise the cost of western coal, hasten the decline of domestic coal consumption, stop exports of PRB coal, and strand investments made by Wyoming and other states to stimulate the demand for U.S. coal abroad.

To understand the rationale for these proposed changes, the next section provides a brief overview and critique of several recent studies on federal coal royalty policies. Section three discusses the Department of the Interior's proposed rules for setting coal royalties with a specific focus on the default provision, which would likely provide a vehicle for arbitrarily increasing the price of PRB coal. Economic issues arising from the proposed valuation methods and the default provision are discussed in the subsequent two sections. The likely effects of the proposed rule changes on prospects for PRB coal exports are examined in section six. This policy brief ends with a short summary of the main findings and recommendations.

II. Policy Background

There has been a series of reports and studies examining the system for leasing and setting royalties on federal coal. Some of the studies create a misleading impression of a broken system, alleging that coal-marketing affiliates are reaping excess profits at the expense of federal taxpayers. For example, Thakar and Madowitz (2014) argue that PRB coal is under-valued, claiming a lack of competition in coal leasing, and arguing this lack of competition explains why PRB coal sells for less than half the price of Appalachian coal. In contrast, studies in the peer-reviewed literature, such as Considine (2013) and Gerking and Hamilton (2008) show that very low extraction costs due to technological innovations and economies of scale are the main reasons for relatively low prices for PRB coal. Moreover, Considine and Larson (2006) show that low-sulfur coal, such as PRB coal, reduces the cost of meeting SO_2 emission control standards.

A royalty in principle is a payment to an owner of a natural resource for ***depletion*** as the resource is extracted. The federal coal royalty rate is 12.5% for surface mines and 8.5% for underground mines. Royalty payments are determined by multiplying this royalty rate by the gross revenues on coal sales at or near the mine, which are equal to the product of the market price and tonnage produced. Thakar and Madowitz (2014), however, argue that mine-mouth prices should not be used to determine the basis for royalty payments. Instead, they suggest that end use prices, which include transportation and marketing costs, should be used as a basis to determine federal coal royalties. This would mean, therefore, that railroads and logistics coordinators would pay federal royalties in addition to mining companies. Since railroads and logistics coordinators do not mine coal, such a royalty valuation scheme would amount to imposing a resource depletion tax on transportation and logistic services. In this case, a royalty that includes these downstream services would run contrary to the principle of depletion based royalty payments. Indeed, the Department of the Interior (2015) asked for comments on a proposal to include 50% of coal transportation costs in federal coal royalties.

Thakar and Madowitz (2014) also argue that federal coal royalties should include a carbon fee to compensate American taxpayers for the environmental costs of burning coal and to prevent exports of coal that could offset any emission reductions achieved by the Obama Administration's Clean Power Plan. Krupnick et. al (2015) find that the Department of Interior could have legal authority to impose such a fee but it would likely be litigated. They point out, however, that there are serious economic flaws with including a carbon fee in federal coal royalty rates. Mid-range estimates for the social cost of carbon from the Interagency Working Group (2013) of $46 per ton of carbon emissions would translate to a fee of more than $90 per ton on PRB coal. Krupnick et al. (2015) suggest that such a fee could shutdown PRB coal production.

The Krupnick et al. (2015) study also points out that assessing carbon fees on federal coal would create market distortions, such as encouraging production of coal on private lands and increasing the demand for coal imports. Considine and Larson (2006) demonstrate that PRB coal in particular has been instrumental in meeting stringent SO_2 emission controls. Moreover, PRB coal reduces the cost of meeting new emission controls on air toxics, such as mercury.

Internationally, if foreign consumers of U.S. coal have carbon emission control policies, any higher emissions from consuming U.S. coal would have to be offset with emission reductions elsewhere. Hence, the carbon leakage problem would be mitigated by the lack of carbon emission controls abroad. Moreover, PRB coal has considerably less SO_2 and mercury content than many foreign coals. Limiting PRB coal exports, therefore, would encourage the consumption of coals abroad with relatively greater emissions of criteria pollutants contributing to considerably higher environmental costs that are more certain than environmental costs associated with greenhouse gas emissions.

These insights imply that a single-minded focus on controlling greenhouse gas emissions through carbon fees attached to federal coal royalties would have several adverse unintended consequences. So why are these considerations relevant for the seemingly innocuous changes proposed by the Department of Interior for royalty determination? The next section demonstrates that the default provision proposed by the Department of Interior provides an open door to implement the aforementioned attempts to raise the cost of federal coal.

III. The Proposed Regulations

The U.S. Department of Interior's (2015) recently proposed changes to the rules for determining coal royalty payments. The proposed rules would revise the methods used to value coal to assess royalties. Given the vertically integrated nature of the coal industry as described by Joskow (1985), a significant amount of coal from the Powder River Basin is sold at transfer prices between coal mining companies and their marketing affiliates. The alternative is to rely on contracts between mining companies and coal marketers. Designing these contracts or renegotiating them as market conditions change can incur substantial litigation costs. Hence, vertical integration is a way to reduce or minimize these transaction costs.

Under the current rules, these transfer prices are determined based upon prices reached by arm's length or non-affiliate transactions for coal with similar quality and locational characteristics in the same time. ONRR is now proposing a royalty value for coal at the affiliate resale price if a lessee sells coal using a transfer price. For mine-mouth power plants, ONRR proposes to value coal at the mine mouth using a net back from the price of electricity.

Under the current system of royalties, companies and the Department of Interior can renegotiate royalty valuations if circumstances change or if underpayment of royalties is alleged. In contrast, ONRR is now proposing a "default provision," that would allow them to elect not to apply regulatory valuation standards for coal but to instead unilaterally establish a "reasonable" royalty value on a case-by-case basis using a variety of discretionary factors.

IV. Coal Valuation

There are a number of economic issues raised by these proposed regulatory changes. The idea of extending the regulatory reach forward through the supply chain to end-use markets could prove to be administratively unworkable, difficult, and contentious, and likely prone to litigation. Markets are efficient in determining mineral asset values. If a coal deposit on private land, for example, has low thermal value, high ash content, and is far away from consumers, then coal companies would discount this property relative to coal reserves with high energy content, low ash, and close proximity to end-users. Hence, the market price for coal leases would reflect this underlying value. In other words, coal and energy markets already operate efficiently to value coal leases and royalties by taking into account the myriad of factors that determine the value of coal reserves.

The long history of policies to regulate energy production on the basis of cost demonstrates that departures from market based pricing are fraught with problems. Such intervention either proves administratively too complex or creates serious market distortions that lead to shortages and price increases to consumers. The only justification for not using market prices to value coal leases is the existence of imperfect competition. Coal companies, however, operate in very competitive markets and are unlikely, therefore, to exercise any monopoly or buying power to artificially suppress prices for coal leases.

Even if such policies were administratively feasible, basing coal valuation on downstream market prices for delivered coal or electricity makes little economic sense. A coal lease is a long-term contract between a coal company as the lessee and the federal government as the lessor. The federal government owns the coal and provides the lessee with access to extract that coal under the terms of the lease. In addition to leasing fees, the producer then also pays a resource depletion tax, or royalty, on each ton of coal extracted. Hence, the price of the coal lease is the price of access or the value of coal in the ground, while the royalty pays for the depletion of that resource. This results in great benefit to the government and taxpayers for what would be a stranded asset while the lessee incurs the significant majority of risk.

When this coal is sold either to a third party or a marketing affiliate, these firms add value to the coal by arranging transportation and delivery. An electric power generation company then buys this coal and adds additional value by producing electricity. Marketing and electric generation companies currently pay income taxes on these earnings. Including downstream services in coal royalty valuations would be double taxation. Hence, coal producers would be forced to abandon transfer pricing and instead rely on independent third parties for coal marketing and logistics services.

This would change the structure of the coal industry in America, leading to the break-up of the vertically integrated organization of the industry that has efficiently reduced transaction costs to a minimum. An illustration of the existing industry structure and the likely re-organization of the industry from the proposed rule changes are presented in Figure 1. Under approximated current market conditions, coal exports from the Montana portion of the PRB are not profitable since the mine profit of $3.60 per ton are more than offset by a negative profit on coal logistics of roughly $5 per ton (see Figure 1).

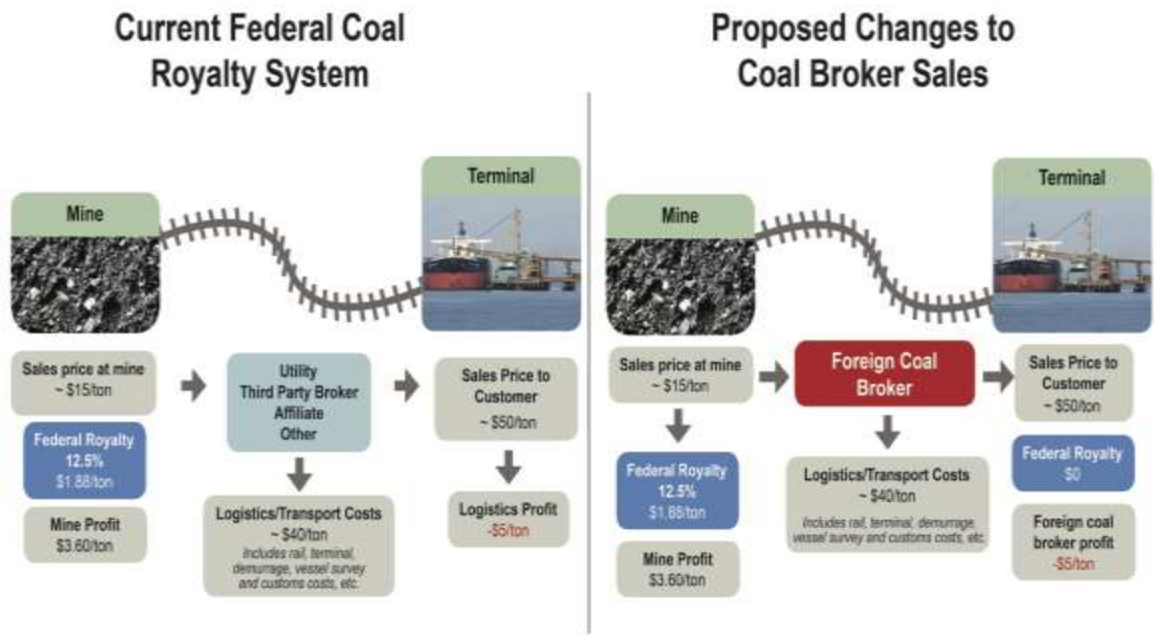

Figure 1: Industry Structure Before and After Proposed Rule Changes

The proposed rule changes on industry structure are illustrated in the right panel of Figure 1 in which marketing affiliates are shut-down by U.S. coal companies and replaced by foreign coal brokers for coal export sales. Under this new industry structure, once international coal prices recover any profits earned by brokers would be transferred abroad to these foreign entities. The proposed ONRR rule would not impose any royalty on the logistics and transport services of foreign coal brokers, only on the logistics and marketing arms of U.S. producers. As a result, state and federal governments would fail to generate any additional revenue versus the current rules while punishing U.S. coal producers and potentially sending profits from coal brokering on export sales overseas. This situation is exacerbated by the default provision, which is now discussed.

V. The Default Provision

The default provision, however, is potentially the most damaging provision for PRB coal because it is open ended and would create a great deal of uncertainty. The "default provision" in the draft rule would allow ONRR to set at their own discretion, the value for coal sales and royalty valuation purposes if, in their view and without any reference to objective criteria, the sale price was 10% or more below what they deem to be "fair market value." No process for determining "fair market value" is presented in the rule, unlike current benchmarks used for over twenty years. What is a reasonable royalty valuation? Should it be based upon downstream coal resale prices? Or should the value be based upon the price of electricity? Should the value include a carbon fee?

Even if it is rarely exercised as the Department of Interior claims, the very presence of the default provision creates considerable risk and, therefore, imposes significant transactions costs. All federal coal royalty payments are subject to audits that often take place 6-8 years after a coal sale. Unlike oil royalties that are allowed to be determined on the basis of published price indices and ONRR's proposal that gas should also be afforded reference to such indices, the coal royalty valuation proposed by ONRR is based upon an ill-defined "net back" concept. This method takes the gross proceeds of the first arm's length sale of coal and then asks the seller to deduct "transportation costs" in order to arrive at the mine mouth value of the coal. The rule only allows for deduction of undefined "transport costs" and does not specify deductions for other costs incurred in getting the coal to its first arm's length sale in a marketable condition.

Coal companies have responsibilities to their shareholders. The possibility that the default provision would be invoked, allowing the Secretary of the Interior to set any value upon which the 12.5 percent royalty would be due, would require coal companies to set aside funds to cover any discrepancy between their understanding of the royalty "net back" calculation and the ONRR estimate of "fair market" value for the royalty. In addition, firms would need to set aside additional funds to cover possible penalties and interest. As written, the rule would allow the Secretary to set a valuation of $1000 per ton for coal that may have sold for $50 per ton. Thus, $125 per ton would be due.

Financial prudence would demand a conservative approach and, therefore, substantial contingency funds would be required to be held for several years until royalty payments are audited. Using current export terminal capacity under development, PRB producers may have access to roughly 100 million tons export opportunities. Given the uncertainty created by the "default provision" and the contingencies that producers might be required to carry to meet subsequent valuation discrepancies, at a $10 per ton provision, the rule could require PRB producers to accrue up to $1 billion per year.

VI. Impacts on PRB Coal Export Prospects

Establishing these royalty contingency funds is unlikely to be financially feasible given the small profit margins and limited cash flow of coal companies. As a result, the proposed rules would likely render uneconomic any new investments in additional coal production and delivery capacity. Domestic coal shipments are likely to be significantly lower under the Obama Administration's proposed Clean Power Plan and other regulations. Hence, the only prospect for offsetting these losses is higher coal exports, which is placed in considerable jeopardy by the proposed royalty rule changes.

To understand how the proposed rule changes would affect the prospects for coal exports from the PRB, a few salient features of international coal markets must be understood. Coal is the number one growth fuel in the world economy over the past decade, supplying the world with more than 1.4 billion tons of additional oil equivalent energy compared with 742 million tons of oil equivalent from natural gas (see Figure 2). The third largest contributor was oil with 544 million tons. New hydroelectric supplies were the fourth largest source of growth followed by renewable power sources, such as wind and solar, with 218 million tons of oil equivalent. Nuclear power's contribution actually decreased during from 2003 to 2013.

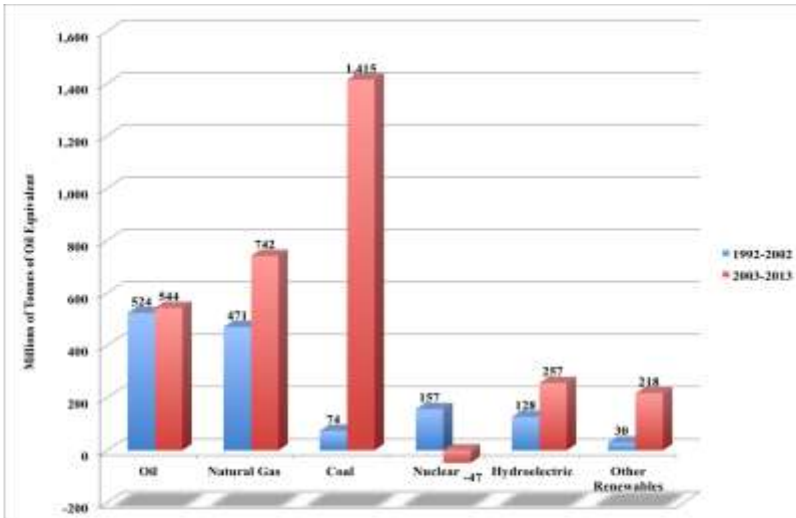

Figure 2: Average Incremental Changes in World Energy Consumption

So despite what the current Administration tries to do to limit domestic coal consumption and exports, the world will adopt the least cost option for generating electric power, which is most often coal in many regions around the world. While this consumption raises greenhouse gas emissions, the social benefits from bringing electricity to millions of impoverished people around the world are considerable. Moreover, limiting PRB coal exports would simply encourage the substitution of coal with higher sulfur and mercury content with significantly negative impacts on human health and the environment.

If the United States does not export coal to meet these global needs for energy, other coal producers abroad will. Total world coal exports rose 69% from 835.1 million tons in 2003 to 1.41 billion tons in 2013. The top ten coal exporters, displayed in Figure 3, accounted for 97.6% of total world coal exports in 2012. Indonesia and Australia are the dominant coal exporters with 422 and 332 million tons respectively, which together account for 58% of world coal exports. The United States is in third place with 116 million tons of exports, much of which is exported from the Appalachian basins through east coast facilitates. Russia, Columbia, and South Africa are also significant exporters. Most of these exports are shipped to Europe and Asia.

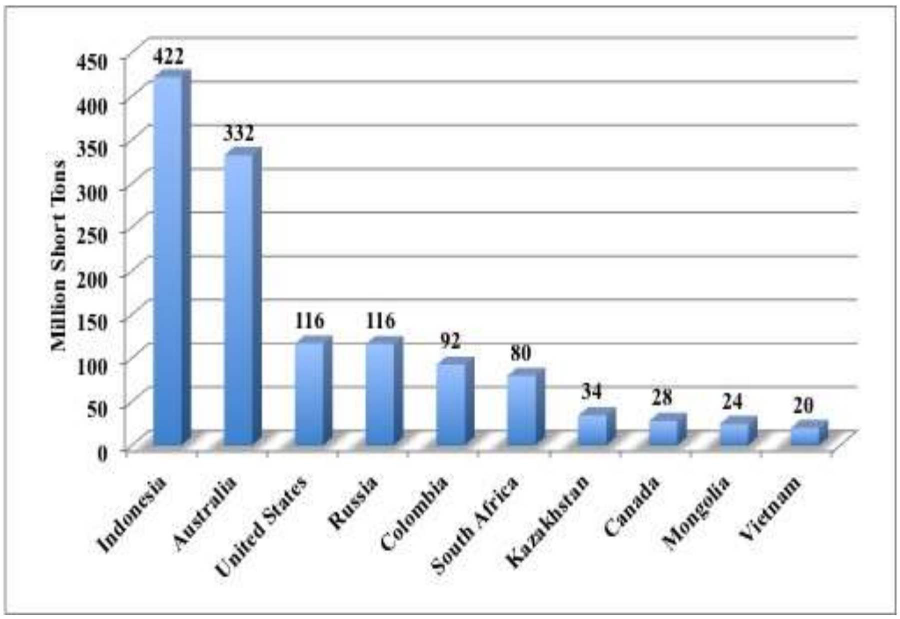

Figure 3: Top Ten Coal Exporting Nations

Most U.S. exports are metallurgical grade coal, also known as coking coal, used to make coke for iron making in the steel industry. The U.S. exported 70 million tons of metallurgical grade coal during 2011 and 2012, up considerably from 37 million tons during 2009 (see Figure 4). The world steel industry consumed over 700 million tons of coking coal in recent years.

Wyoming does not produce metallurgical grade coal. U.S. exports of steam coal used in electric power generation increased from 22 million tons in 2009 to 56 million tons in 2012 but then dropped to 52 million tons during 2013 due to lower export demand and lower coal export prices (see Figure 4). Also included in Figure 3 are exports of petroleum coke, which is produced by petroleum refineries and used primarily as a fuel in electric power and cement production. Prior to 2011, U.S. petroleum coke exports often exceeded steam coal exports. Coal exports declined during 2013 in part due to lower coal export prices (see Figure 5).

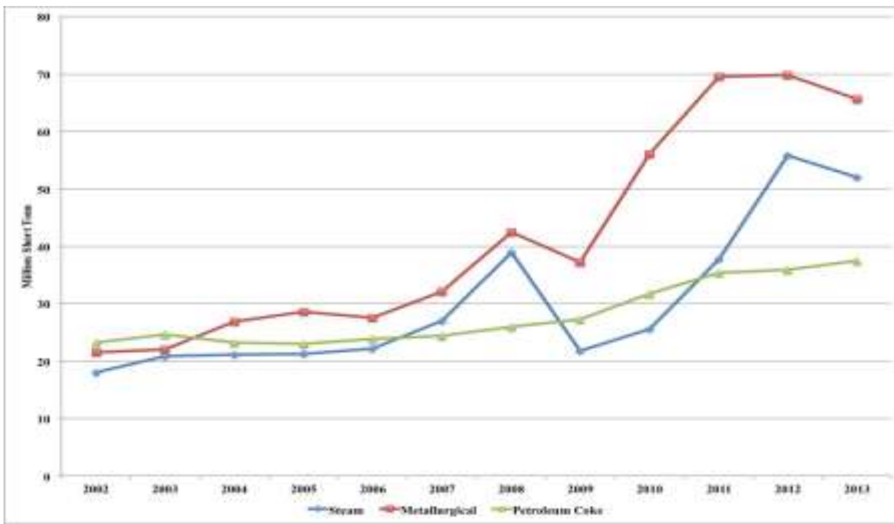

Figure 4: U.S. Coal and Petroleum Coke Exports, 2002-2012

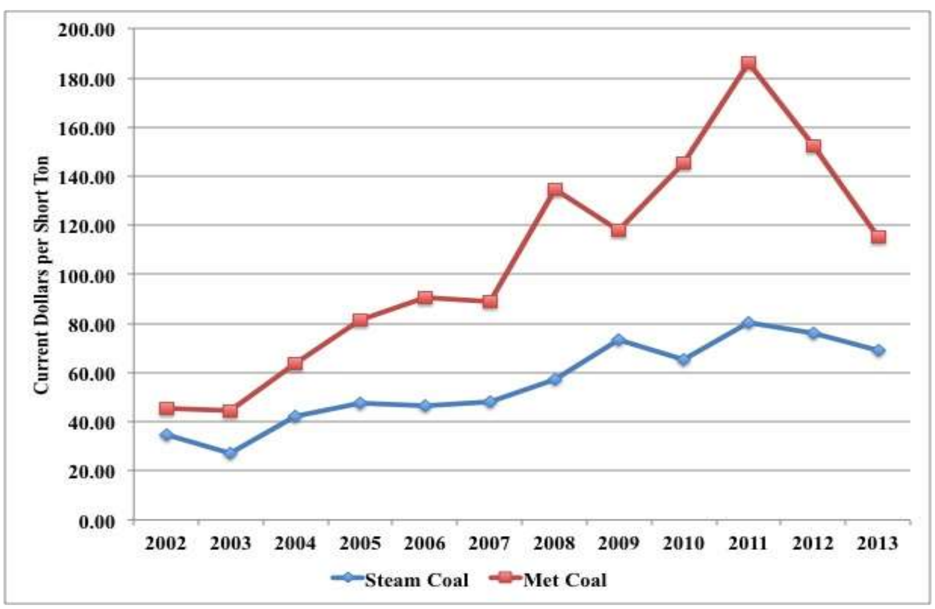

Figure 5: U.S. Coal Export Prices, 2002-2012

Most of the growth in steam coal exports from the U.S. has come from an increase in demand from Europe and to a lesser extent Asia (see Figure 6). U.S. exports of steam coal to Europe were over 32 million tons, comprising 58 percent of total U.S. steam coal exports, during 2012. The Asia Pacific region bought 12.4 million tons or 18 percent of total U.S. steam coal exports during 2012.

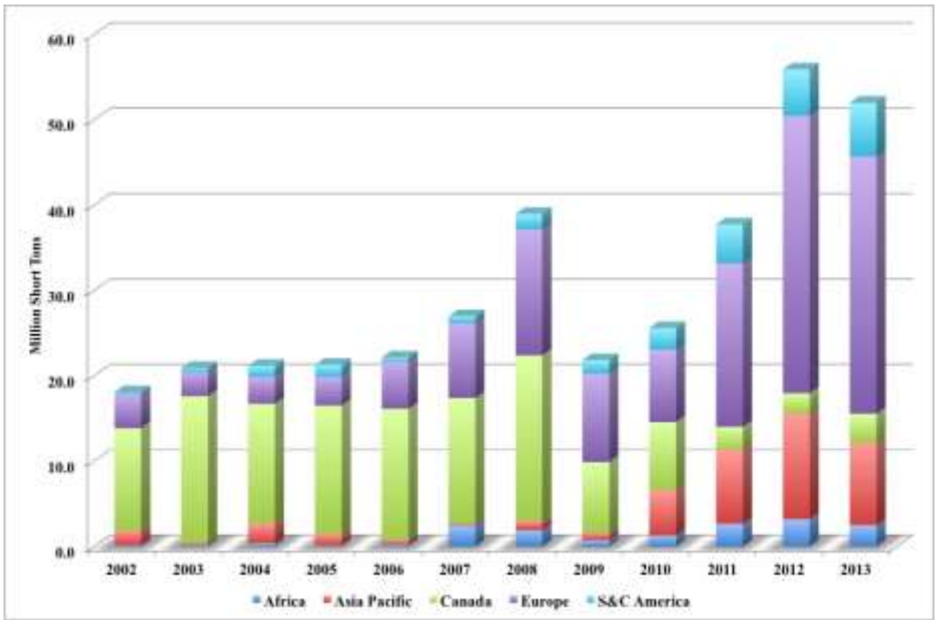

Figure 6: U.S. Coal Exports by region, 2002-2012

Given the size of the international coal market and the highly competitive costs of PRB coal production, Wyoming has the potential to export significantly greater amounts of PRB coal. Despite this promise, however, Wyoming coal producers have yet to achieve significant access to international customers (see Figure 7). Moreover, over the past ten years, exports of coal from Wyoming to international destinations declined while coal exports from other regions of the United States surged. These divergent trends reflect the absence of metallurgical coal production in Wyoming and the relatively high costs of getting Wyoming coal to ports for shipment overseas.

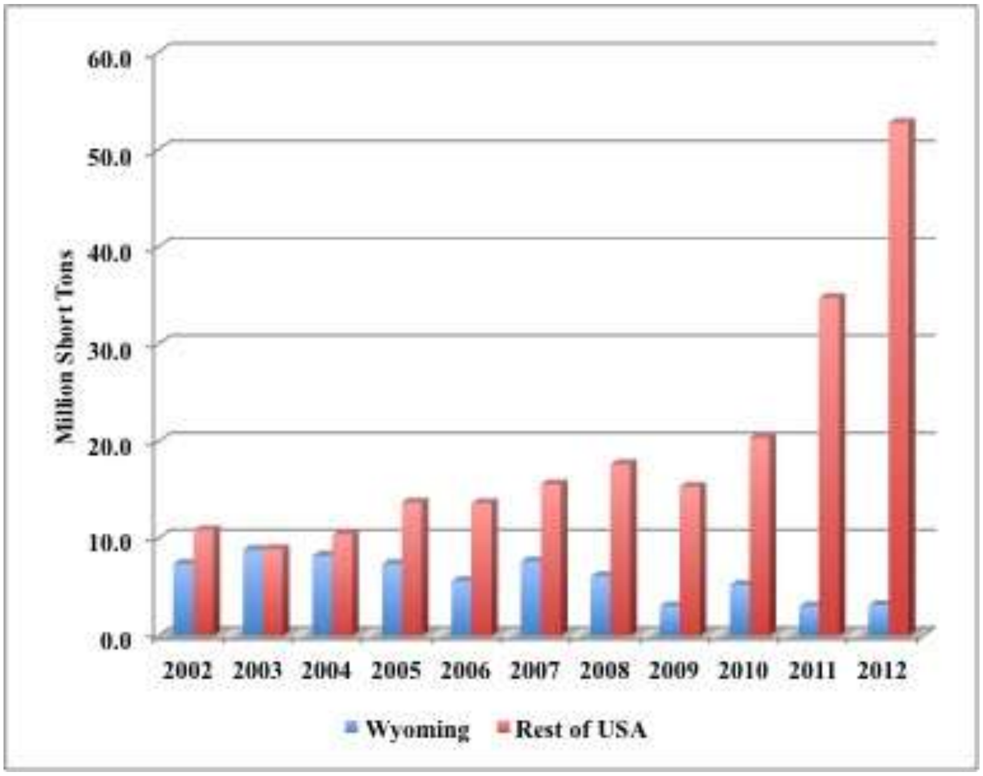

Figure 7: Steam Coal Exports from Wyoming & Rest of USA, 2002-2012

One of the key obstacles in making higher coal exports from Wyoming a reality is environmental opposition to port expansions in the Pacific Northwest. According to Schaefer (2012), there were more than 150 million tons of coal export capacity proposed in Oregon and Washington. Several proposed facilities, however, recently have been canceled for economic reasons so the current projection is now approximately 100 million tons. Even if half of this capacity is built and with additional export capacity in the Gulf Coast region and even Canada, coal exports could partially offset reductions in domestic PRB coal shipments.

So currently PRB coal is at the margin, poised to expand service to international customers but currently under threat from opposition to port expansions on the west coast and more recently from the proposed royalty rule changes discussed above. Seemingly small changes in royalties can have significant impacts on the export possibilities for PRB coal.

The proposed rule changes discussed above would most likely eliminate any profit margin on PRB coal exports to Asia. An illustration of the possible effects and uncertainties associated with the proposed rule changes on profits for coal export sales are illustrated in Figure 8. Under the proposed netback policy, profits on coal exports based on Q1 2015 prices are -$0.04, or essentially zero. Any recovery of international coal prices would likely restore the profitably of coal exports and revive incentives to export PRB coal.

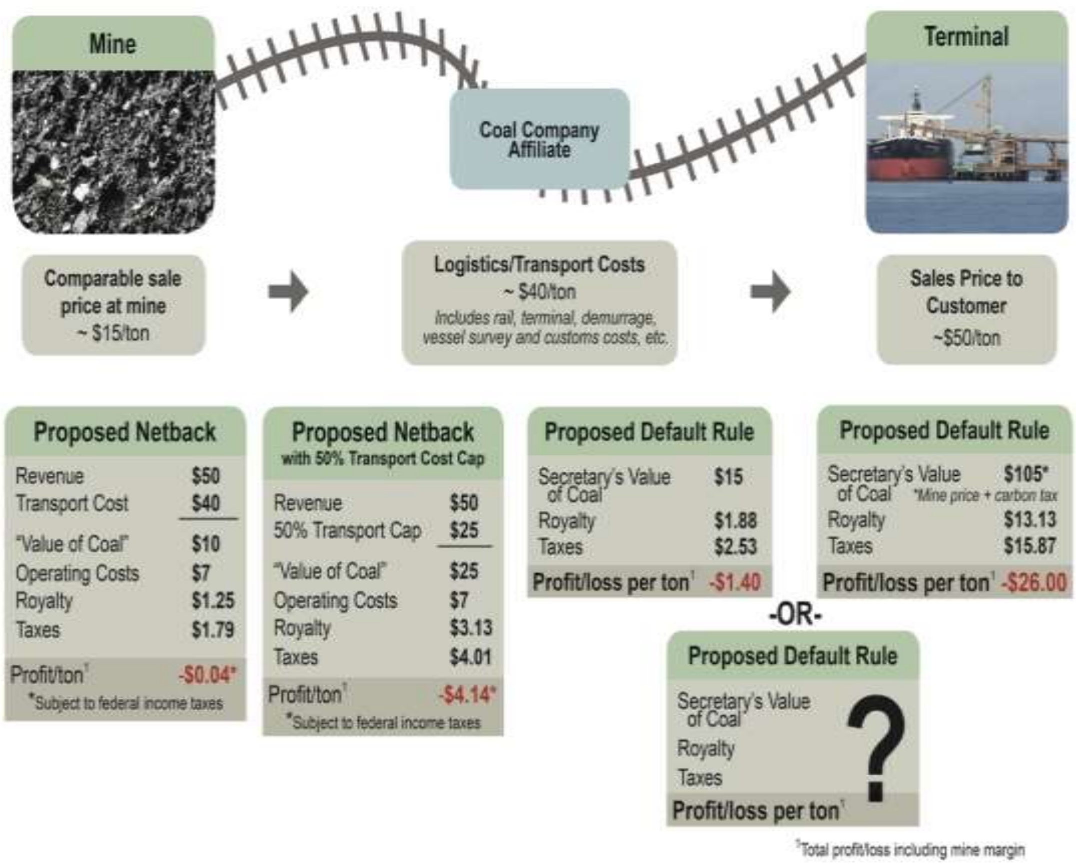

Figure 8: Possible Impacts on Coal Export Profitability

The proposed rule changes, however, make this prospect less likely. For instance, if a 50% transport cost cap is implemented, profits on coal exports from the PRB fall to -$4.14 (see Figure 8). If a carbon fee is erroneously assessed, profits on coal export sales would be -$26 per ton, which would clearly render any coal exports from the PRB uneconomic and, therefore, unlikely to be realized. The criteria for setting coal royalties under the default provision, however, are not defined and, therefore, expected profits from future PRB coal exports would not be known under the proposed default provision. What is clear is that this uncertainty entails real financial costs that firms must bear in the interim between infrastructure development and future coal export sales. These additional transaction costs arising from uncertainty would reduce these expected profits even further from those estimated in Figure 8.

This analysis suggests that the proposed rule changes would likely forestall any future growth in PRB coal exports. Our observations about U.S. coal exports, however, indicate that efforts to make federal coal more expensive would not affect the bulk of U.S. coal exports, which are primarily metallurgical grade coal and Appalachian steam coal that would be unaffected by the proposed rule changes. While the export potential for PRB coal is significant, it is constrained by limited port capacity to the Pacific basin. Finally, profit margins on shipping coal from the PRB to Asia have been falling in recent years and are currently next to nothing or result in marginal losses for some companies. These market realities suggest that the proposed changes to rules determining royalties on coal extracted from federal lands and the resulting risk premium required would likely eliminate the already thin profit margins from exporting PRB coal. The end result of the proposed rule changes would be the elimination of coal exports from federal lands in the U.S.

VII. Recommendations

If the proposed rules were adopted, the most likely outcome would be the loss of considerable volumes of potential future coal exports, upwards of 100 million tons of coal per year. Under this scenario, U.S. taxpayers would lose roughly $200 million per year in royalty income from lost federal coal production arising from the effects of the proposed rule changes.

The proposed rule changes for royalty determination are ill defined and actually represent a step back from existing rules by creating unnecessary uncertainty that raises transactions costs on coal exports. If royalty valuation needs reform, a far better approach would be to establish royalties on federal coal based upon published price indices for PRB, similar to the methods proposed for federal oil and gas. Finally, the proposed default provision would force coal companies to carry significant financial liabilities to protect their shareholders from unilateral royalty re-valuation by ONRR. These transactions costs would likely force firms to re-organize their operations to spin-off coal marketing affiliates and to abandon efforts to seek new markets abroad for PRB coal. The proposed default provision, therefore, is a bad idea and should not be adopted.

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