Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for US Coal Used in Power Generation

Article *in* SSRN Electronic Journal · September 2015

DOI: 10.2139/ssrn.2627865

3 authors:

Mark Haggerty

Headwaters Economics

Megan Lawson

Headwaters Economics

Jason Pearcy

Montana State University

Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for US Coal Used in Power Generation*

Mark Haggerty[†] Megan Lawson[‡] Jason Pearcy[§]

August 10, 2015

Abstract

The ONRR has proposed to reform federal coal valuation policy for royalty assessment and in this paper we estimate the expected changes associated with different reform options. We find that if royalty revenues are determined using the delivered price of coal instead of prices used in non-arm's length transactions, royalty revenues from domestic sales to power generators would increase by $141 million per year. The associated price effect is an increase of 23 cents per ton (0.89%) and the effect on the quantity is a decrease of 971 thousand tons per year (-0.17%). In addition to using delivered prices for royalty valuation if transportation costs that exceed 50% of the net delivered price are included in royalty payments, royalty revenues from domestic sales to power generators are expected to increase by $517 million per year. This change would increase the average price of coal by 88 cents per ton (3.36%), decrease the quantity extracted by 3.7 million tons per year (-0.65%), and reduce severance and income tax collections by $13 million per year.

JEL Classification: D4, H2, L7, Q3

Keywords: Coal, Royalty Revenue, Policy Evaluation.

*For useful comments we thank Roger Coupal, Tyler Hodge, Diane Kearney, Mike Mellish, Robert Shanks, and James Stock. Any errors are the authors'. Pearcy acknowledges financial support from Headwaters Economics.

[†]Headwaters Economics; mark@headwaterseconomics.org

[‡]Headwaters Economics; megan@headwaterseconomics.org

[§]Montana State University; jason.a.pearcy@gmail.com

1 Introduction

Royalty revenues and bonus payments for all minerals extracted from public lands and waters represents the largest non-tax source of income for the US government. In 2014, the US government received $704 million in royalty payments from federal coal leases. The federal government owns roughly one-third of coal reserves in the US, and coal production from federal leases is approximately 43 percent of total domestic coal production (Humphries & Sherlock, 2013). The Bureau of Land Management (BLM) and the Office of Natural Resources Revenue (ONRR) administer the federal coal leasing program and have multiple and diverse objectives: a fair return for US taxpayers, economic development and jobs, energy costs and security, and environmental protection.

The ONRR has proposed to reform the way federal coal is valued for the purpose of assessing federal royalties.[1] Currently, royalties are assessed on the proceeds of coal from the first transaction. If this first sale is between affiliated parties, i.e., not at arm's length, the lessee follows a series of five benchmarks defined by the ONRR to estimate the market value of the coal. These benchmarks are difficult to follow, are not transparent to the public, and may lower the price of coal below market prices, reducing the royalty value to the federal government (GAO, 2013). A main concern occurs when a mine sells coal to an affiliated logistics/marketing company who then sells the coal to an end consumer, e.g. a power plant, at a higher price. The concern in this case is that the price used for royalty valuation is based on the lower price from the first affiliated sale rather than the higher price paid by the end consumer net transportation costs. The proposed reform would eliminate the benchmarks and use the first arm's length sale of coal, i.e. the delivered price net transportation costs, for royalty valuation in all instances.

The ONRR projects that this change will have little to no impact on federal royalty collections, but casual market observations indicate otherwise. In many cases, there are differences between the free on board (fob) prices at the mines and the delivered prices to power plants that are not entirely explained by transportation costs. The average price reported to ONRR for royalty payments in Montana and Wyoming is $15.30 and $12.74 per ton respectively (see Table 1). Using coal deliveries, we find that the average prices for coal (net transportation costs) extracted in Montana and Wyoming are $22.03 and $15.40 respectively (see Table 3). If delivered prices are

[1] See the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform, 80 Fed. Reg. 607 (proposed Jan. 6, 2015) (to be codified at 30 C.F.R. pts. 1202 & 1206).

20% greater than the prices used for royalty valuation, as suggested by these data, then one might expect a significant change in federal royalty collections when delivered prices are used for royalty valuations.[2]

This paper evaluates two options for how the regulation could be finalized responding to two questions posed by the ONRR. The proposed reform asks what alternative methods might be used to value coal sold in non-arms length sales, and whether transportation cost deductions should be limited. The two options we assess are whether the ONRR should value coal based on delivered prices net of transportation costs, and whether transportation costs deductions should be limited to 50 percent of the value of coal.

The reforms we consider are expected to increase royalty revenue and the cost of delivering coal to the domestic power sector. Increases in the average price of coal and decreases in the quantity of coal extracted are expected as well. To estimate the expected magnitudes of these changes, we construct a partial equilibrium model with relevant policy variables. The equilibrium condition of our model is implicitly differentiated with respect to the relevant policy variables to determine the comparative statics of the model. Our analysis focuses just on coal extracted for use in the domestic electric power sector (91% of the market) at the state-year level for states with federal leases over the fiscal years 2008-2014. We use data on quantities, prices, transportation costs and elasticities of supply and demand to estimate the how the reforms we consider affect prices, quantities, and royalty revenues. Additionally, an increase in royalty revenues is expected to lead to a decrease in state severance tax and income tax collections.[3] Our model captures these tax interactions and we estimate the associated changes in severance and income taxes.

We find that when royalty valuations are based on delivered prices of coal, average total royalty revenues increase by $141 million per year. The 90% confidence interval associated with the change in royalty revenues is an annual increase in revenue between $106 million per year and $176 million per year. We find that the average increase in price is 23 cents per ton (0.89%) and the decrease in the quantity of coal extracted is 971 thousand tons per year (-0.17%). Severance and income tax collections are expected to decrease by $4 million per year, easily offset by the increase in royalty

[2]While there are other possible explanations for the price differences, these explanations would be similarly captured by the proposed policy reform of using delivered prices for royalty valuation.

[3]If state severance taxes are also based on prices from non-arm's length transactions, then it is possible that royalty revenues and severance taxes will increase. The current analysis excludes any reform at the state level and we find that state severance taxes decrease.

revenues.

When the value of coal is based on delivered prices net of transportation costs, and when transportation costs deductions are limited to 50 percent of the value of coal, we find that royalty revenues are expected to increase by $517 million per year. This change would increase the average price of coal by 88 cents per ton (3.36%), decrease the quantity extracted by 3.7 million tons per year (-0.65%), and reduce severance and income tax collections by $13 million per year. We find evidence of heterogenous impacts across states, with a much larger impact for the Powder River Basin (PRB) states of Wyoming and Montana where more coal is extracted from federal leases and transportation costs are greater.

Previous research on federal royalties/state severance taxes from coal by Kolstad and Wolak (1983), Alt, Baumann, and Zimmerman (1983), and Kolstad and Wolak (1985) consider competition across states when setting severance taxes and the optimal severance tax rates. The policy changes considered in this paper do not involve across state competition as federal royalty rates apply uniformly across states.[4] There is also a large literature focused on policy changes in markets for non-renewable resources. A majority of these studies consider how policies interact with the temporal dynamics of the model and focus on optimal extraction paths over time. Optimal taxation with non-renewable resources is considered by Gamponia and Mendelsohn (1985), Ranck (1985), Yücel (1986), Yücel (1988), Yücel (1989), and Rowse (1997). These studies differ with respect to the types of taxes considered and the given market structure. The overarching finding is that royalty/severances taxes are effective methods to generate revenue with limited tax burdens.[5]

One main difference between previous studies and the current analysis is that our focus is on static changes in prices, quantities, and revenue collections rather than dynamic extraction paths. This focus motivates the use of a partial equilibrium model and an advantage of the current approach is the relative simplicity of the partial equilibrium model. It is also important to note that our analysis is retrospective and it is unclear how our model, or any related model, might preform with future, out of sample, predictions. While our analysis reflects on changes in previous years, it

[4]In Section 4.5 we discuss why coal from different states/basins are imperfect substitutes and why the policy changes we consider are unlikely to cause substitution across states.

[5]More recent studies such as Deacon (1993), Kunce (2003), Kunce, Gerking, and Morgan (2004), Kunce, Gerking, Morgan, and Maddux (2003), and Chakravorty, Gerking, and Leach (2010) focus on the dynamics of the oil and gas industry. Many of these studies assume that prices are exogenous and focus on the dynamic implications of changes in policy. Of particular relevance for the oil and gas industry is how changes in policy affect exploration over time, but changes in exploration are not as relevant for the coal industry.

highlights the importance of reforming the assessment of federal coal royalties for the future.

2 Model

The foundation of the analysis is based on a partial equilibrium model with general forms of demand and supply. Federal tax policies and other features specific to coal markets are introduced on the demand and supply side. The model is used to determine how a change in the price of coal used for royalty valuation and changes in the deductibility of transportation costs affect equilibrium outcomes of coal markets. A change in the valuation of coal is modeled as an increase in the federal royalty rate from a lower effective rate based on delivered prices to a potentially higher statutory rate based on reported prices.[6] Two different changes in transportation cost deductions are considered: one where firms may deduct transportation costs that are a fraction of the price, and another change where firms may only deduct a share of the transportation costs (independent of the price). The equilibrium outcomes of interest are the changes in the prices and quantities of coal as well as changes in federal royalty payments. Additionally, we consider changes in state severance taxes and corporate income tax revenue based on the interactions between royalty payments and the tax base for these federal, state, and local production and income taxes.

The quantity demanded of coal is specified as a function of the price paid by a utility/generation facility where $Q = D(p + T)$. Q is the total volume of coal delivered, the net price of coal is p, and T is the transportation cost per unit of coal delivered to the utility/generation facility. In the US, utilities typically pay for the cost of transporting coal from the mine to their generation facility making the gross price for a unit of coal $p + T$. The market supply of coal is $Q = S(p_s)$ where p_s is the price per unit of coal retained by the mine/seller in an arm's length transaction. The net price, p differs from p_s due to royalty and tax payments. In the absence of these payments $p = p_s$.

Let τ_r be the federal royalty rate, and assume that the per unit royalties are levied on the gross price of coal. The ONRR currently allows transportation costs to be deducted from royalty payments. In this paper, we consider two changes in this policy. The first policy determines the transportation cost deduction as a proportion of the price. Let $\beta \in [0, \infty)$ be this proportion of the

[6] The change in valuation does not change the royalty rate, but from a modeling perspective changing the price used for valuation is equivalent to changing the royalty rate. Since the market equilibrium is determined using delivered prices regardless of whether delivered or reported prices are used to value coal for royalty purposes, we model the change in valuation as a change in the royalty rate.

price and let $\hat{T} = \max\{T - \beta p, 0\}$. On a per-unit basis, a mine receives p and must pay $\tau_r p + \tau_r \hat{T}$ in royalties. In our analysis below, we abuse notation by using $\frac{\partial \hat{T}}{\partial p}$ and $\frac{\partial \hat{T}}{\partial \beta}$ terms. These partial derivatives are defined piecewise where

$$\frac{\partial \hat{T}}{\partial p} = \begin{cases} 0 & \text{if } T - \beta p < 0 \\ -\beta & \text{otherwise} \end{cases} \qquad \frac{\partial \hat{T}}{\partial \beta} = \begin{cases} 0 & \text{if } T - \beta p < 0 \\ -p & \text{otherwise} \end{cases}.$$

The other policy we consider determines the transportation cost deduction as a share of the transportation costs. Let $\gamma \in [0, 1]$ be this share where on a per-unit basis, a mine receives p and must pay $\tau_r p + \tau_r \gamma T$ in royalties. Combining both types of transportation cost policies, the mine must pay $\tau_r p + \tau_r(\gamma T + \hat{T})$ as a per-unit royalty payment. The current ONRR policy has β becoming infinite and $\gamma = 0$ so that royalties are levied just on the net price of coal. When $\beta = 0$ or when $\gamma = 1$, no portion of the transportation costs are deductible from royalty payments. In the analysis of our model, we compare marginal changes in β to marginal changes in γ.

In addition to royalties, mines pay state severance taxes on the value of coal (including local government production taxes on the value of coal) and corporate income taxes on profits. Some states use ad-valorem severance taxes, but others use a per-unit tax or both. Let τ_s be the ad-valorem state severance tax rate and τ_s' is the per-unit rate. Ad-valorem state severance taxes are levied on the remaining revenue after royalty payments and average severance taxes from mines on federal land are $\tau_s\Big((1 - \tau_r)p - \tau_r(\gamma T + \hat{T})\Big) + \tau_s'$. If a state only uses an ad-valorem severance tax, then $\tau_s' = 0$, and when $\tau_s = 0$ only the per-unit tax is used. Income taxes are embodied by τ_c, where τ_c is a proxy for the federal and state corporate income tax rate.[7] Corporate income taxes depend on costs and revenue. With regards to costs, it is assumed that all mines experience constant returns to scale given their current production levels. Overall production may exhibit different scale relationships, but in the range of production levels considered, the average cost is a constant c. Corporate income taxes are levied on profits after severance taxes and royalties, and average corporate income taxes from mines on federal land are $\tau_c(1-\tau_s)\Big((1-\tau_r)p-\tau_r(\gamma T+\hat{T})\Big)-\tau_c\tau_s'-\tau_c c$.

Combining corporate income taxes, severance taxes and royalties, the average price a mine on

[7] It is possible to have separate federal and state corporate income tax rates, but they are combined here for simplicity. If τ_{cf} is the federal corporate tax rate and τ_{cs} is the rate for the state, the combined rate is $\tau_c = \tau_{cf} + \tau_{cs} - \tau_{cf}\tau_{cs}$.

federal land receives for coal is

$$p_s = (1-\tau_c)(1-\tau_s)\Big((1-\tau_r)p - \tau_r(\gamma T + \hat{T})\Big) - (1-\tau_c)\tau_s' + \tau_c c.$$

One final institutional detail incorporated into the analysis is that federal royalties are only levied on coal extracted from federal land. Let $\alpha \in [0,1]$ be the share of production from federal leases where a share of $1-\alpha$ of total production has a royalty rate of $\tau_r = 0$. The equilibrium condition of the model is

$$\begin{aligned} D\Big(p+T\Big) = \alpha S\Big((1-\tau_c)(1-\tau_s)\Big((1-\tau_r)p - \tau_r(\gamma T + \hat{T})\Big) - (1-\tau_c)\tau_s' + \tau_c c\Big) \\ + (1-\alpha) S\Big((1-\tau_c)\Big((1-\tau_s)p - \tau_s'\Big) + \tau_c c\Big) \end{aligned} \tag{1}$$

and this condition implicitly defines the equilibrium price p^* as a function of the tax rates and other parameters including β, γ, T and c. The equilibrium quantity is determined by either the demand or supply function where using the demand function $Q^* = D(p^* + T)$. Total royalty collections (RTR) are

$$\text{RTR} = \tau_r \alpha Q^* \Big(p^* + \gamma T + \hat{T}\Big). \tag{2}$$

The severance tax revenue (STR) is

$$\text{STR} = \tau_s Q^* \Big((1-\alpha\tau_r)p^* - \alpha\tau_r(\gamma T + \hat{T})\Big) + \tau_s' Q^*. \tag{3}$$

Total corporate income tax revenue (CITR) is as follows.

$$\text{CITR} = \tau_c Q^* \Big((1-\tau_s)\Big((1-\alpha\tau_r)p^* - \alpha\tau_r(\gamma T + \hat{T})\Big) - \tau_s' - c\Big). \tag{4}$$

2.1 A Change in the Royalty Rate

Implicitly differentiation equation (1) to consider how a marginal change in the royalty rate affects the equilibrium price.

Result 2.1. *A marginal change in τ_r results in the following change in the equilibrium price:*

$$\frac{\partial p^*}{\partial \tau_r} = \frac{\alpha(1-\tau_c)(1-\tau_s)\left(p^* + \gamma T + \hat{T}\right)\eta}{(1-\tau_c)(1-\tau_s)\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)\eta - \epsilon}$$

where ϵ is the price elasticity of demand and η is the price elasticity of supply.

It is expected that $\frac{\partial p^*}{\partial \tau_r} \geq 0$ so that an increase in the royalty rate results in an increase in the price for coal. With tax rates between 0 and 1, $\epsilon \leq 0$, and $\eta \geq 0$, it must be that $\frac{\partial p^*}{\partial \tau_r} \geq 0$. The increase in the price will be greatest when demand is perfectly inelastic ($\epsilon = 0$) or when supply is perfectly elastic (η becomes infinite), and the largest increase in price expected is $\alpha\left(p^*+\gamma T+\hat{T}\right)/\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)$.[8] Alternatively, the increase in price will be the smallest when demand is perfectly elastic (ϵ becomes infinitely negative) or when supply is perfectly inelastic ($\eta = 0$), and in these cases, the price does not change with a marginal increase in the royalty rate. Combining the extreme cases for the price change, the price change is bounded as follows.

Lemma 2.2. *Assume that $\epsilon \in (-\infty, 0]$ and $\eta \in [0, \infty)$, then*

$$\frac{\partial p^*}{\partial \tau_r} \in \left[0, \frac{\alpha\left(p^* + \gamma T + \hat{T}\right)}{\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)}\right].$$

Using the demand or supply function, the change in the quantity resulting from a marginal change in the royalty rate is

$$\begin{aligned}
\frac{\partial Q^*}{\partial \tau_r} &= \epsilon \frac{Q^*}{p^*}\frac{\partial p^*}{\partial \tau_r} \\
\frac{\partial Q^*}{\partial \tau_r} &= (1-\tau_c)(1-\tau_s)\eta\frac{Q^*}{p^*}\left(\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)\frac{\partial p^*}{\partial \tau_r} - \alpha\left(p^* + \gamma T + \hat{T}\right)\right)
\end{aligned}$$

where the top term comes from the demand function and the bottom from supply. For both terms, $\frac{\partial Q^*}{\partial \tau_r} \leq 0$. With perfectly inelastic supply or perfectly inelastic demand, $\frac{\partial Q^*}{\partial \tau_r} = 0$. The quantity changes the most when either supply is perfectly elastic or when demand is perfectly elastic. With

[8] As η becomes infinite, the limit is evaluated using L'Hôpital's Rule.

perfectly elastic supply, the change in quantity is

$$\left.\frac{\partial Q^*}{\partial \tau_r}\right|_{\eta=\infty} = \frac{\alpha\epsilon Q^*\left(p^* + \gamma T + \hat{T}\right)}{p^*\left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right)}$$

where $\eta = \infty$ implies that η becomes infinite. The change in quantity with perfectly elastic demand is

$$\left.\frac{\partial Q^*}{\partial \tau_r}\right|_{\epsilon=-\infty} = \frac{-\alpha(1-\tau_c)(1-\tau_s)\eta Q^*\left(p^* + \gamma T + \hat{T}\right)}{p^*}.$$

Note that when demand and supply are perfectly elastic, a marginal change in τ_r does not change the price, but results in an infinite decrease in the quantity. Since this case is not realistic, the change in the quantity is bounded as follows.

Lemma 2.3. *Assume that $\epsilon \in (-\infty, 0]$, $\eta \in [0, \infty)$, and that ϵ does not become infinitely negative when η becomes infinite, then*

$$\frac{\partial Q^*}{\partial \tau_r} \in \left[\min\left\{\left.\frac{\partial Q^*}{\partial \tau_r}\right|_{\epsilon=-\infty}, \left.\frac{\partial Q^*}{\partial \tau_r}\right|_{\eta=\infty}\right\}, 0\right].$$

Not allowing for ϵ to become infinitely negative when η becomes infinite rules out the case of perfectly elastic supply and demand.

Besides changes in the equilibrium price and quantity, a marginal change in the royalty rate affects royalty collections, severance tax collections, and income tax collections. Royalty revenue is defined in equation (2) and the change in the royalty revenue due to a marginal change in the royalty rate is

$$\frac{\partial \text{RTR}}{\partial \tau_r} = \alpha\left(p^* + \gamma T + \hat{T}\right)\left(Q^* + \tau_r\frac{\partial Q^*}{\partial \tau_r}\right) + \tau_r\alpha Q^*\frac{\partial p^*}{\partial \tau_r}\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right).$$

The $\frac{\partial \text{RTR}}{\partial \tau_r}$ term cannot be signed, but note that all the terms are positive except for $\frac{\partial Q^*}{\partial \tau_r}$ and $\frac{\partial \hat{T}}{\partial p^*}$. Since both of these terms are multiplied by τ_r, it can be said that for relatively small values of τ_r, a marginal increase in the royalty rate results in greater royalty revenues, but that this change is ambiguous with relatively larger values of τ_r.

The changes in the severance tax and corporate income tax revenues are determined similarly to the change in royalty collections. The change in the severance tax due to a marginal change in the royalty rate is

$$\frac{\partial \text{STR}}{\partial \tau_r} = \tau_s\Big((1-\alpha\tau_r)p^* - \alpha\tau_r(\gamma T + \hat{T})\Big)\frac{\partial Q^*}{\partial \tau_r} + \tau_s\left(1 - \alpha\tau_r\Big(1 + \frac{\partial \hat{T}}{\partial p^*}\Big)\right)Q^*\frac{\partial p^*}{\partial \tau_r}$$
$$- \alpha\tau_s Q^*\big(p^* + \gamma T + \hat{T}\big) + \tau_s'\frac{\partial Q^*}{\partial \tau_r}$$

and the change in corporate income tax revenue is

$$\frac{\partial \text{CITR}}{\partial \tau_r} = \tau_c\left((1-\tau_s)\Big((1-\alpha\tau_r)p^* - \alpha\tau_r(\gamma T + \hat{T})\Big) - \tau_s' - c\right)\frac{\partial Q^*}{\partial \tau_r}$$
$$+ \tau_c(1-\tau_s)\left(1 - \alpha\tau_r\Big(1 + \frac{\partial \hat{T}}{\partial p^*}\Big)\right)Q^*\frac{\partial p^*}{\partial \tau_r} - \alpha\tau_c(1-\tau_s)Q^*\big(p^* + \gamma T + \hat{T}\big).$$

The signs of these comparative statics are ambiguous resulting in an uncertain change in severance taxes and corporate income taxes. The inability to sign both $\frac{\partial \text{CITR}}{\partial \tau_r}$ and $\frac{\partial \text{STR}}{\partial \tau_r}$ highlights the relevance of the empirical analysis.

2.2 A Change in β

A change in β represents a change in the deductibility of transportation costs as a proportion of the net price. Implicitly differentiating equation (1), a marginal increase in β affects the price as follows.

Result 2.4. *A marginal change in β results in the following change in the equilibrium price:*

$$\frac{\partial p^*}{\partial \beta} = \frac{\alpha(1-\tau_c)(1-\tau_s)\tau_r\frac{\partial \hat{T}}{\partial \beta}\eta}{(1-\tau_c)(1-\tau_s)\left(1 - \alpha\tau_r\Big(1 + \frac{\partial \hat{T}}{\partial p^*}\Big)\right)\eta - \epsilon}.$$

With tax rates between 0 and 1, $\epsilon \leq 0$, and $\eta \geq 0$, it must be that $\frac{\partial p^*}{\partial \beta} \leq 0$. Currently, transportation costs are fully deductible from federal royalty payments, so β is infinite. A marginal decrease in β, $\partial\beta < 0$, results in a marginal increase in the price, $\partial p^* > 0$, as more transportation costs are included in the value against which federal royalty liability is assessed.

The possible values of the price elasticity of demand and supply bound the possible values of $\frac{\partial p^*}{\partial \beta}$. When demand is perfectly elastic or when supply is perfectly inelastic, then $\frac{\partial p^*}{\partial \beta} = 0$.

Alternatively when demand is perfectly inelastic or when supply is perfectly elastic, then $\frac{\partial p^*}{\partial \beta} = \alpha\tau_r \frac{\partial \hat{T}}{\partial \beta} / \left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right)$. Combining these two cases bounds the change in the price as follows.

Lemma 2.5. *Assume that $\epsilon \in (-\infty, 0]$ and $\eta \in [0, \infty)$, then*

$$\frac{\partial p^*}{\partial \beta} \in \left[\frac{\alpha\tau_r \frac{\partial \hat{T}}{\partial \beta}}{\left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right)}, 0\right].$$

The demand and supply functions are used to determine how a marginal decrease in β affects the equilibrium quantity. These changes are

$$\begin{aligned}
\frac{\partial Q^*}{\partial \beta} &= \epsilon \frac{Q^*}{p^*} \frac{\partial p^*}{\partial \beta} \\
\frac{\partial Q^*}{\partial \beta} &= \eta \frac{Q^*}{p^*} (1 - \tau_c)(1 - \tau_s) \left(\left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right) \frac{\partial p^*}{\partial \beta} - \alpha\tau_r \frac{\partial \hat{T}}{\partial \beta} \right)
\end{aligned}$$

where the first equation is from the demand and the second equation is from the supply function. We expect $\frac{\partial Q^*}{\partial \beta} \geq 0$, so that a decrease in β, $\partial\beta < 0$, results in a decrease in the quantity, $\partial Q^* < 0$. With a perfectly inelastic demand or supply, a marginal change in β does not change the quantity. If demand is perfectly elastic the change in quantity is

$$\left.\frac{\partial Q^*}{\partial \beta}\right|_{\epsilon=-\infty} = -\eta \frac{Q^*}{p^*} (1 - \tau_c)(1 - \tau_s) \alpha\tau_r \frac{\partial \hat{T}}{\partial \beta},$$

and when supply is perfectly elastic the change in quantity is

$$\left.\frac{\partial Q^*}{\partial \beta}\right|_{\eta=\infty} = \epsilon \frac{Q^*}{p^*} \frac{\alpha\tau_r \frac{\partial \hat{T}}{\partial \beta}}{\left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right)}.$$

As before, the change in quantity can be bounded and the bounds are as follows.

Lemma 2.6. *Assume that $\epsilon \in (-\infty, 0]$, $\eta \in [0, \infty)$, and that ϵ does not become infinitely negative when η becomes infinite, then*

$$\frac{\partial Q^*}{\partial \beta} \in \left[0, \max\left\{ \left.\frac{\partial Q^*}{\partial \beta}\right|_{\epsilon=-\infty}, \left.\frac{\partial Q^*}{\partial \beta}\right|_{\eta=\infty} \right\}\right].$$

A change in β also results in a change in royalty and tax collections. The change in royalty revenue is

$$\frac{\partial \text{RTR}}{\partial \beta} = \tau_r \alpha \big(p^* + \gamma T + \hat{T}\big) \frac{\partial Q^*}{\partial \beta} + \tau_r \alpha Q^* \left(\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right) \frac{\partial p^*}{\partial \beta} + \frac{\partial \hat{T}}{\partial \beta} \right).$$

This change cannot be signed, but the first term is positive and the second term is negative. Overall, if $\frac{\partial \text{RTR}}{\partial \beta} < 0$, then a decrease in the deductibility of transportation costs results in an increase in royalty collections. The change in severance tax is

$$\frac{\partial \text{STR}}{\partial \beta} = \tau_s \Big((1 - \alpha\tau_r) p^* - \alpha\tau_r (\gamma T + \hat{T}) \Big) \frac{\partial Q^*}{\partial \beta} + \tau_s Q^* \left(\left(1 - \alpha\tau_r \left(1 + \frac{\partial \hat{T}}{\partial p^*} \right) \right) \frac{\partial p^*}{\partial \beta} - \alpha\tau_r \frac{\partial \hat{T}}{\partial \beta} \right) + \tau_s' \frac{\partial Q^*}{\partial \beta},$$

and the change in corporate income tax is

$$\begin{aligned} \frac{\partial \text{CITR}}{\partial \beta} = \tau_c \Big((1 - \tau_s) \Big((1 - \alpha\tau_r) p^* - \alpha\tau_r (\gamma T + \hat{T}) \Big) - \tau_s' - c \Big) \frac{\partial Q^*}{\partial \beta} \\ + \tau_c (1 - \tau_s) Q^* \left(\left(1 - \alpha\tau_r \left(1 + \frac{\partial \hat{T}}{\partial p^*} \right) \right) \frac{\partial p^*}{\partial \beta} - \alpha\tau_r \frac{\partial \hat{T}}{\partial \beta} \right). \end{aligned}$$

2.3 A Change in γ

Finally, consider a marginal increase in γ where this change affects the price as follows.

Result 2.7. *A marginal change in γ results in the following change in the equilibrium price:*

$$\frac{\partial p^*}{\partial \gamma} = \frac{\alpha(1 - \tau_c)(1 - \tau_s)\tau_r T \eta}{(1 - \tau_c)(1 - \tau_s)\left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right)\eta - \epsilon}.$$

Under the usual assumptions regarding tax rates, ϵ and η, $\frac{\partial p^*}{\partial \gamma} \geq 0$. Examining the limiting values of ϵ and η allows us to place bounds on this price change.

Lemma 2.8. *Assume that $\epsilon \in (-\infty, 0]$ and $\eta \in [0, \infty)$, then*

$$\frac{\partial p^*}{\partial \gamma} \in \left[0, \frac{\alpha\tau_r T}{\left(1 - \alpha\tau_r\left(1 + \frac{\partial \hat{T}}{\partial p^*}\right)\right)} \right].$$

The changes in quantity due to a marginal increase in γ are

$$\begin{aligned}
\frac{\partial Q^*}{\partial \gamma} &= \epsilon \frac{Q^*}{p^*}\frac{\partial p^*}{\partial \gamma} \\
\frac{\partial Q^*}{\partial \gamma} &= \eta \frac{Q^*}{p^*}(1-\tau_c)(1-\tau_s)\left(\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)\frac{\partial p^*}{\partial \gamma} - \alpha\tau_r T\right)
\end{aligned}$$

where the top change is determined from the demand function and the bottom change is from supply. A marginal increase in γ, results in a decrease in the quantity, $\frac{\partial Q^*}{\partial \gamma} \le 0$, and the decrease in the quantity is bounded by the minimum of $\frac{\partial Q^*}{\partial \gamma}\Big|_{\epsilon=-\infty}$ and $\frac{\partial Q^*}{\partial \gamma}\Big|_{\eta=\infty}$. When demand is perfectly elastic the change in quantity is

$$\frac{\partial Q^*}{\partial \gamma}\bigg|_{\epsilon=-\infty} = -\eta\frac{Q^*}{p^*}(1-\tau_c)(1-\tau_s)\alpha\tau_r T,$$

and when supply is perfectly elastic the change in quantity is

$$\frac{\partial Q^*}{\partial \gamma}\bigg|_{\eta=\infty} = \epsilon\frac{Q^*}{p^*}\frac{\alpha\tau_r T}{\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)}.$$

In addition to the changes in price and quantity, royalty and tax collections experience the following changes due to a marginal increase in γ.

$$\begin{aligned}
\frac{\partial \mathrm{RTR}}{\partial \gamma} &= \tau_r\alpha\big(p^*+\gamma T+\hat{T}\big)\frac{\partial Q^*}{\partial \gamma} + \tau_r\alpha Q^*\left(\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\frac{\partial p^*}{\partial \gamma} + T\right) \\
\frac{\partial \mathrm{STR}}{\partial \gamma} &= \tau_s\Big((1-\alpha\tau_r)p^* - \alpha\tau_r(\gamma T+\hat{T})\Big)\frac{\partial Q^*}{\partial \gamma} + \tau_s Q^*\left(\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)\frac{\partial p^*}{\partial \gamma} - \alpha\tau_r T\right) + \tau_s'\frac{\partial Q^*}{\partial \gamma} \\
\frac{\partial \mathrm{CITR}}{\partial \gamma} &= \tau_c\bigg((1-\tau_s)\Big((1-\alpha\tau_r)p^* - \alpha\tau_r(\gamma T+\hat{T})\Big) - \tau_s' - c\bigg)\frac{\partial Q^*}{\partial \gamma} \\
&\quad + \tau_c(1-\tau_s)Q^*\left(\left(1-\alpha\tau_r\left(1+\frac{\partial \hat{T}}{\partial p^*}\right)\right)\frac{\partial p^*}{\partial \gamma} - \alpha\tau_r T\right).
\end{aligned}$$

Comparing changes in γ to changes in β, a marginal increase in γ is similar to a marginal decrease in β. Both of these changes increase the royalty payments associated with transportation costs. Examining the different price, quantity and revenue terms, note that marginal changes in γ include T terms where marginal changes in β include $\frac{\partial \hat{T}}{\partial \beta}$ terms. From above, $\frac{\partial \hat{T}}{\partial \beta}$ is either $-p^*$ or 0 depending on the relationship between T, β, and p^*.

There are at least two main differences between marginal changes in γ compared to marginal changes in β. First, changes in β contain threshold effects where a marginal change in β may have no effect depending on the value of $\frac{\partial \hat{T}}{\partial \beta}$. Thus a decrease in β may affect some markets, but not others. A marginal change in γ does not contain threshold effects, so a marginal increase in γ affects all markets. The second main difference is that the effect of a marginal change in γ is based on the value of T while the effect of a marginal change in β is based on the value of p^*. This is because γ is reflective of the share of transportation costs that are deductible and β is reflective of the amount of transportation costs that are deductible as a proportion of the price.

3 Data

Demand in the US coal market is primarily driven by electricity generation, as this sector accounts for 93% of all coal used in the US between 2008-2014 (EIA, 2015a). Due to data limitations related to delivered prices and transportation costs, we ignore coal exports, coke, comercial use, and coal used by industrial consumers.[9] The level of analysis in this report is at the state-year level for the nine states with reported federal coal royalty collections over the fiscal years 2008 to 2014. While our analysis includes important coal producing states like Wyoming, Kentucky, and Montana, other important states like West Virginia, Illinois, and Pennsylvania are excluded due to the lack of mining on federal leases in those states. While these excluded states will presumably be affected by the policy changes we consider, we expect these effects to be minimal compared to the nine states with federal royalty collections.[10]

Five types of information are used in the analysis. State-year data regarding federal royalty collections are reported by the ONRR. Data on market prices, transportation costs and quantities delivered to the domestic power sector are from SNL Financial. Severance tax and corporate income tax rates are gathered from various state sources. Finally, price elasticities of supply and demand are determined using publicly available information from Hodge (2012) and the EIA (2015b). The own price elasticities we use are determined from estimates allowing for interfuel substitution between coal and natural gas.

[9] The share of deliveries to the electric power sector varies by state. Deliveries from the PRB are largely used in electricity generation.

[10] In Section 4.5 we discuss the heterogeneity in coal from different states/basins and the large fixed costs associated with substituting coal from different states/basins.

The ONRR (2015) reports state-year production on federal leases, the corresponding sales value, and federal royalty collections. Using this information, we determine the average price used for royalty valuation, and the average statutory royalty rate. The averages are determined as annual averages across the seven years in our sample and are reported in Table 1.[11] The statutory royalty rate in Table 1 varies from a low of 2.3% in North Dakota to a high of 12.3% in Wyoming. In general, royalty rates are set at 12.5% for coal extracted from surface mines and 8% for coal from underground mines. The statutory rates we find are lower due to royalty rate reductions granted by the BLM to address economic conditions and promote full recovery of leased federal coal.

It is important to note that the information reported by the ONRR includes all coal extracted from federal leases. This includes coal exports and coal used outside of the electric power sector. Currently the ONRR does not provide sufficient information to separately identify coal royalty payments from coal used in different sectors. Since our analysis focuses on coal used for electricity generation, the average prices we determine using the ONRR data are biased. Table 2 lists the average prices of coal stratified by the end use of coal. Since the average prices of coal used for electricity generation are lower than other uses, we overestimate the average price of coal used for royalty valuation, resulting in an underestimate of the difference between the mine price and net delivered prices – a measure of the extent that non-arm's length transactions occur.

Information on all monthly coal deliveries to the electric power sector between October, 2007 and September, 2014 (fiscal years 2008-2014) were obtained from SNL Financial. These data include identifiers for the mine (MSHA ID)[12] and plant, tons delivered, delivered cost per ton, estimated transportation costs, and original transportation mode (barge, mine mouth, railroad, or truck). Out of the 144,205 records obtained, 19,261 records (13.4%) contain missing information and are removed from the dataset.

For each state-year, we determine the total quantity extracted, the production weighted price, and the production weighted transportation cost. State-year quantities are determined from all mine deliveries, and the average prices and transportation costs are determined from mine deliveries from mines that have active federal leases.[13] Average annual quantities, prices and transportation

[11] Table 25 in the appendix presents the state-year statutory royalty rates.

[12] The MSHA ID is a mine identifier assigned by the US Department of Labor Mine Safety and Health Administration.

[13] Mines with active federal leases are matched by their MSHA ID to a list provided by the BLM obtained via a Freedom of Information Act request.

costs and are reported in Table 3. Wyoming and Kentucky are the highest producing states in our sample. The share of coal extracted on federal land, α, is low in Kentucky, making Wyoming, Colorado and Montana the three states with the highest levels of production subject to federal royalty payments. Alabama and Kentucky are the states with the highest average transportation costs, but transportation costs as a ratio of the average price is highest in Wyoming and Montana. This distinction is important as all else equal, a marginal change in γ will have a larger impact in Alabama and Kentucky, and a marginal change in β will have a larger impact in Wyoming and Montana.

In addition to state-year observations, we divide each state-year into H, M and L subgroups based on the ratio of transportation costs to the net price. These subgroups describe state-year observations with high, medium or low transportation costs relative to the net price. Each transaction within a state-year group with $T/p \geq 1$ is placed into the H group. Transactions with $1 > T/p \geq 0.5$ are in the M group, and the remaining transactions are in the L group. These subgroups add precision when determining the effects associated with a marginal decrease in β.[14]

Also included in Table 3 are the average annual values of α (the quantity of coal extracted from federal leases as a share of the total quantity of coal extracted) by state.[15] State-year values of α are determined by dividing the state-year quantity of federal coal reported by the ONRR, by the total state-year quantity reported by the MSHA (2015). Both the numerator and denominator used to determine α include all coal extracted, including exports and other industrial uses: an unconditional value of α. We assume that the share of production from federal leases, conditional on the coal being used in the electric power sector, is equal to the unconditional value of α. Ideally we would have values of α determined just from coal used in the electric power sector, but this data is not available.[16]

Both Table 1 and Table 3 include net prices for coal used in the electric power sector. The prices in Table 3 are based on deliveries to utilities and the prices in Table 1 are based on information reported to ONRR for federal royalty collections. As already indicated, the prices in Table 1 are

[14]State-year observations of the quantities, prices and transportation costs for each subgroup are reported in Tables 26 and 27 of the appendix. Note that not all subgroups are represented as some states do not have mine level transactions included in a particular subgroup.

[15]Table 28 includes state-year values of α.

[16]The mine level transaction data does not sufficiently distinguish whether coal is extracted on a federal lease as some mines span land covered by a federal lease and land covered by a state/private lease.

biased upwards, and even with this bias, we find that in some states the average price based on deliveries is greater than the average price used for federal royalty collections. In other states we find the opposite, where the average price used when valuing coal for royalty collections is greater than the average price of coal based on deliveries. We attribute this difference to the upward bias in the average price determined using data from ONRR.

Effective royalty rates are calculated for each state where the average delivered price is greater than the average fob mine price currently used for royalty valuation. To determine the effective royalty rate, we first determine the value of federal coal by multiplying the state-year quantity of federal coal by the state-year average delivered price. The effective royalty rate is obtained by dividing the royalty collections by the value of federal coal based on delivered prices. The average annual effective royalty rates are listed in Table 4.[17]

Also included in Table 4 are the average annual statutory royalty rates and the difference between the effective and statutory rates. The difference between the two rates is the greatest in Montana and Wyoming indicating that these states have the largest difference between reported prices to the ONRR and delivered prices. Because the average prices determined from the ONRR data are biased upwards, the difference between the effective rate and the statutory rate is biased downwards. For New Mexico, Oklahoma, and Utah, we find no difference between the average effective and statutory rates. Since the differences in the rates are biased downwards, the use of non-arm's length transactions may still be prevalent in these states, but we are not able to observe a difference in prices given the current data.

State specific policy variables, including state severance tax rates and corporate income tax rates, are presented in Table 5.[18] Most states use an ad-valorem severance tax, τ_s. Alabama and North Dakota are the only states to use just a per-unit severance tax, τ_s', and Colorado and New Mexico use both. Oklahoma is the only state that does not have any state severance taxes. Also reported in Table 5 are the state corporate income tax rates and the combined state and federal rates, τ_c.[19]

The price elasticity of demand for coal is determined from the demand for electricity generation. Ko and Dahl (2001) survey existing studies and report that the price elasticity of demand for coal

[17]The state-year effective rates are presented in Table 24 of the appendix.
[18]See Haggerty (2015) for more information about how these rates were obtained.
[19]The federal rate is 20% and to determine the combined rate, see Footnote 7.

is inelastic with an average price elasticity of demand for coal reported across the different studies of −0.46. Both Ko and Dahl (2001) and Dahl and Ko (1998) examine interfuel substitution for US electricity generation, and estimate both cross fuel price elasticities of demand and own fuel price elasticities using monthly data. Ko and Dahl (2001) find the price elasticity of demand for coal is −0.57 and Dahl and Ko (1998) find a price elasticity of demand of −0.16 using a translog model and −0.26 using a logit model.

The most recent estimates of the price elasticity of demand for coal are determined by Hodge (2012) and are reported in Table 6. Price elasticities are determined using monthly data from 2005-2010, and these estimates are reported at the NERC region.[20] While our level of analysis is at the state level, Bernstein and Griffin (2006) find that NERC regions appropriately capture regional differences in demand that occur at the state level. Coal extracted from one state gets transported to multiple NERC regions, and for each state considered, we determine state-NERC region shares. The price elasticity of demand for coal at the state level is determined as the share weighted NERC region average, and these estimates are reported in Table 7.[21]

Information regarding the price elasticity of supply for coal is limited due to the proprietary nature of this data. A survey by Dahl and Duggan (1996) indicates that the median price elasticity of supply for coal measured by previous studies is 0.79 with values ranging from 0.05 to 7.9. Beck, Jolly, and Loncar (1991) finds a short run elasticity of 0.44 and a long run elasticity of 1.89 for Australia. Analysis by EIA (2001) indicates that the price elasticity of supply for coal in the US is somewhere between 1.5 to 3.0. We use the average price elasticity of supply of coal determined from the US Energy Information Administration's (EIA) Coal Market Module (CMM) model documentation for each year from 2005 to 2010.[22] The average price elasticity of supply we use is 2.4232 with an approximate standard error of 0.3933. This estimate fits within the range provided by previous studies.

Unlike the price elasticity of demand, the price elasticity of supply for coal is not available

[20] NERC is the North American Electric Reliability Corporation and is divided into eight different regional entities: the Florida Reliability Coordinating Council (FRCC), the Midwest Reliability Organization (MRO), the Northeast Power Coordinating Council (NPCC), the ReliabilityFirst Corporation (RFC), the SERC Reliability Corporation (SERC), the Southwest Power Pool, RE (SPP), the Texas Reliability Entity (TRE), and the Western Electricity Coordinating Council (WECC).

[21] State-group-year estimates are presented in Table 29 of the appendix.

[22] See the EIA (2014) for the latest version of the CMM model documentation. Each year's documentation was obtained from the EIA (2015b). The years 2005 to 2010 are used for consistency with the price elasticity of demand estimates.

at the NERC region level; the US level estimate is used as a state level estimate. Overall, one would expect that the price elasticity of supply of coal for underground mines to be relatively more inelastic compared to surface mines. Estimates for surface mines should also vary across states/regions.

4 Analysis

We determine the average annual impact proposed policy changes have on prices, quantities and revenue/tax collections. In addition to point estimates of the expected annual impact, we also estimate the standard errors associated with the policy changes.[23] To establish a baseline for revenue and tax collections, Table 8 presents the expected revenues determined from equations (2), (3), and (4). All the revenue measures reported in Table 8 are determined using the net prices and transportation costs listed in Table 26 and the quantities from Table 27. Royalty revenues are determined using the effective royalty rates (Table 24), and tax collections utilize the state policy variables listed in Table 5. An estimate of the average cost, c, is required to estimate baseline corporate income tax revenues. Since we lack sufficient information regarding firm costs, throughout our analysis we use a value of c that is 80% of the price.

Baseline royalty revenues are expected to closely match actual royalty collections since the effective royalty rates are determined from the ONRR's information on royalty collections. Total royalty revenues average \$654 million per year with \$560 million per year being generated in Wyoming. Colorado, Montana, and Utah are the other states with larger annual royalty collections with \$36, \$25, and \$22 million respectively.

Unlike royalty revenues, we do not expect our baseline severance tax and income tax collections to match actual collections–except for Oklahoma which has no severance tax. Tax collections are based on statutory rates rather than effective rates. The statutory rates reported in Table 5 are used, as we lack sufficient information on actual tax collections to determine effective tax rates. If a state grants a reduction in their severance tax rate or if some part of corporate income taxes are deductible, then the effective rates will be lower than the statutory rates resulting in an overestimate of tax collections.

[23] Section A of the appendix describes how the expected values and variances are determined.

An additional bias is introduced to baseline tax collections as we use net prices from coal deliveries to determine collections. If the prices reported to the ONRR are used when determining taxes, particularly severance taxes, then actual tax collections will be lower. This bias also results in an overestimate of tax collections and our baseline estimates of severance and income tax collections are overstated. Below we discuss how these biases affect our predictions of the change in tax collections and the corresponding percentage changes.

4.1 Changes in the Royalty Rate

It is expected that an increase in the royalty rate from the effective rate to the statutory rate, results in an increase in the net price and a decrease in the quantity of coal extracted. The expected changes in prices are reported in Table 9. We exclude New Mexico, Oklahoma and Utah as we do not observe a difference between the effective and statutory royalty rate.[24] On average, we expect coal prices to increase by 23 cents which represents a 0.89% increase in the price of coal. The price effects are heterogeneous across states with the largest expected increase occurring in Montana: 42 cents or 1.92%. The third column of Table 9 lists the standard error associated with the expected price change. The fourth and fifth columns of Table 9 present 90% confidence intervals associated with the price change. We truncate these confidence intervals by the theoretical limits associated with the price change described in Lemma 2.2. Overall, we find that there is a 90% chance that the price of coal will increase any where between 25 and 19 cents per ton when net delivered prices are used for the valuation of coal.

The expected changes in quantities are presented in Table 10. Overall, it is expected that the quantity of coal extracted decreases by 970 thousand short tons per year: a decrease of 0.17%. The largest effect on a tonnage basis occurs in Wyoming (-900 thousand tons), but on a percentage basis the largest decrease occurs in Montana (-0.26%).

Table 11 lists the expected changes in royalty revenues and tax collections. Total royalty revenues are expected to increase by $141 million per year, a 22% increase. The combined expected decrease in severance and income taxes is $4 million per year, a decrease of 0.16% and 0.81%. While not reported in Table 11, the 90% confidence interval associated with the change in royalty revenues

[24]These three states may still be affected by a change in the valuation of coal that we cannot observe due to an upward bias in our estimates of the effective royalty rates.

is an annual increase in revenue between \$106 million per year and \$176 million per year. Of the \$141 million per year increase in royalty revenues, \$128 million per year occurs from production in Wyoming and \$11 million per year occurs from production in Montana. On a percentage basis, these states also have large percentage increases.

As stated above, our estimates of the baseline severance and income tax collections are biased upwards because we use statutory tax rates that do not include any deductions. These statutory tax rates are also used to determine the change in tax collections and result in an overstatement of the change in tax collections reported in Table 11. On a percentage basis, since the same bias is included in baseline tax collections and the changes, we expect the percentage change in tax collections we find to be more reflective of the actual expected percentage changes.[25]

4.2 Changes in β

Currently transportation costs are fully deductible and royalty revenues are based on the net prices of coal. One proposal considered is to include transportation costs that exceed a proportion of the price into the valuation of coal for royalty payments. In Section 2 we modeled this proposal as a decrease in β, and here we consider two changes in β. The first change is to reduce β to 1 so that royalty payments on transportation costs only occur if transportation costs exceed 100% of the price. The second change is to reduce β even lower to 0.5.

A change in β includes threshold effects, and to properly estimate the changes due to a decrease in β we determine a cutoff value of β, where $\beta_c = T/p$ for each state-group-year. If $\beta > \beta_c$, then $\hat{T} = 0$ and a marginal decrease in β has no effect. If $\beta_c > \beta$, then a marginal decrease in β does have an effect on the market. For a decrease in β to 1, if the value of $\beta_c < 1$ for a state-group-year, then the decrease in β has no effect on that state-group-year. Instead if $\beta_c > 1$, then we consider a change in β from β_c to 1. For this change from β_c to 1, $\hat{T} = 0$, $\frac{\partial \hat{T}}{\partial p} = -\beta_c$, and $\frac{\partial \hat{T}}{\partial \beta} = -p$.

Table 12 presents the changes in prices due to a decrease in β from β_c to 1. Only four states are listed in this table because the decrease in β to 1 only affects type H state-year-groups and not all states have a type H group. With $\beta = 1$, the price of coal is expected to increase by 18 cents per ton with the only significant changes occurring in Wyoming (24 cents per ton) and Montana

[25] With just an ad-valorem severance tax rate, it can be shown that the severance tax rate is not a function of the percentage change in severance taxes.

(5 cents per ton). The expected changes in quantities are presented in Table 13, and at most we expect a 0.2% reduction in the quantity of coal extracted. The expected changes in revenues are included in Table 14. Total tax collections decrease by \$2 million per year, but total royalty revenues increase by \$100 million per year. Almost all of the increase in royalty revenue comes from Wyoming. The 90% confidence intervals associated with the total increase in royalty revenues range from \$65 million per year to \$138 million per year.

Now consider a much larger decrease in β from β_c to 0.5. This change affects both H and M groups and thus affects more states. Table 15 lists the expected changes in prices when β is decreased to 0.5. The expected change in coal prices across all states is an increase of 55 cents per ton, a 2.1% increase. The largest expected increases occur in Wyoming, with an increase of 75 cents per ton (4.87%), and in Montana, with an increase of 19 cents per ton (0.86%). The expected changes in the quantity of coal extracted are presented in Table 16. Overall, the expected change in extraction is a decrease in over 2.3 million tons per year, a 0.42% decrease. Almost all of the quantity change occurs in Wyoming where extraction is expected to decrease by 0.57% per year. Table 17 includes the changes in revenues and collections. A decrease in β to 0.5 is expected to increase royalty revenues by 49% (\$320 million per year) with a 90% chance the increase in royalty revenues is between \$267 and \$374 million per year. The expected decrease in tax collections totals \$8 million per year, less than a 2% decrease in severance taxes and income taxes. An overwhelming majority of the increase in royalty revenues and decreases in tax collections occurs in Wyoming.

4.3 Combining the Policy Changes

Thus far, we have considered an increase in τ_r and a decrease in β separately. We now evaluate what would happen if τ_r was increased from the effective rate to the statutory rate while β is decreased from β_c to 0.5. To evaluate the combined change, we first evaluate the increase in τ_r and then evaluate the decrease in β, taking into account that the increase in τ_r changes prices, quantities and β_c. The combined change differs from a simple sum of each individual change.

Table 18 describes the expected changes in price and quantities for the combined change. Oklahoma is not included as this is the only state not affected by the changes in τ_r and in β. The greatest expected changes occur in Wyoming where the expected increase in price is \$1.18 per ton (7.68%) and the expected decrease in quantity is 3.5 million tons per year (-0.88%). Average prices in the US are expected to increase by \$0.88 per ton (3.36%) and the expected decrease in quantity is 3.7 million tons per year (-0.65%).

Table 19 presents the expected changes in revenue for the combined change. Consistent with earlier results, royalty revenues increase and tax collections decrease. The increase in royalty revenue outweighs the decrease in other tax collections. Total US royalty revenues are expected to increase by \$517 million per year (79%) and tax collections decrease by \$13 million per year; a net increase of \$504 million per year. Again, the largest changes occur in Wyoming where state royalty revenues increase by \$496 million per year (89%) and tax collections decrease by \$12 million per year.

Extending the predictions from Table 19 over the entire seven year period, we find that if in 2008 royalty revenues were based on net delivered prices and $\beta = 0.5$, then total collections would have been \$3.5 billion greater from 2008 to 2014. Even though our estimates of the changes in royalty revenues are biased downwards and the estimates of the tax collections are biased upwards, we still view our results with some caution. Our results are based on a marginal analysis of a partial equilibrium model and currently available data. The changes considered in Table 19 are likely non-marginal and thus are missing changes on any extensive margins. In Section 4.5 we discuss the types of changes that might occur on the extensive margin and the likelihood of these changes.

4.4 An Increase in γ

In Section 4.2 we considered a decrease in β from β_c to 0.5. One potential issue with changes in the deductibility of transportation costs modeled as a decrease in β, is that these changes contain threshold effects. Only coal deliveries with high transportation costs are affected and deliveries with lower transportation costs are not affected at all. Instead of decreasing β, an alternative policy is to increase γ and include all transportation costs in royalty payments on a proportional basis.

Here we consider an increase in γ from 0 to 0.4799 as this change is expected to generate the same increase in royalty revenue as a decrease in β to 0.5. The expected changes in revenues from an increase in γ are reported in Table 22. The total annual increase in royalty revenue is expected to be \$320 million per year which is the same increase reported in Table 17 for a decrease in β to 0.5. The results in Tables 22 and 17 are remarkably similar. The largest difference is for Wyoming where an increase in γ would only increase royalty revenues by \$304 million per year instead of \$313 million per year. The \$9 million per year difference in royalty revenues is made up my increases in royalty revenues in other states.

Table 20 lists the expected changes in prices and Table 21 presents the expected changes in quantities from an increase in γ. Comparing these tables to Tables 15 and 16, both sets of results are very similar. The increase in γ results in a smaller increase in the price and a smaller decrease in the quantity in Wyoming, while other states experience a larger increase in price and a larger decrease in the quantity. Comparing the 90% confidence intervals for Wyoming, the confidence interval associated with an increase in γ fits within the confidence interval associated with an decrease in β to 0.5. With an increase in γ, the price in Wyoming is expected to increase between 77 and 63 cents per ton. With the decrease in β to 0.5, the price in Wyoming is expected to increase between 80 and 60 cents per ton.

4.5 Substitution and Heterogeneity in Coal Markets

Policy reform that increases the cost of coal from federal leases may cause substitution from federal leases to state and private coal leases. Substitution across coal basins could occur if, for example, domestic utilities/generating facilities switch from PRB coal, which is largely extracted from federal leases, to coal from the Illinois Basin where no federal leases exist. Substitution might also occur within a coal basin or state if production can be shifted from mines on federal leases to mines on state/private leases in close proximity.

In our model, these types of substitution would result in a decrease in α, and currently we assume that α is fixed, meaning that substitution between and within states and basins does not occur with the proposed policies. If these types of substitution do occur, then the increase in federal royalty revenues and reduction in state tax collections are likely overstated. Even though our model does not capture these two different types of substitution, our model is well suited to evaluate how the changes in policy considered affect the PRB states of Montana and Wyoming. We expect our results for non-PRB states to be less accurate, since across state and within state substitution is more likely in these states. Even though we are able to less accurately identify the changes in non-PRB states, our overall results still remain valid as our results are driven by changes primarily in Wyoming and Montana.

First, within state substitution of coal extracted from federal leases to coal extracted from state or private leases is less likely to occur in states with higher average values of α. The higher the value of α, the more extraction within the state that occurs on federal leases. Since relatively more productive assets are focused on extracting coal from federal leases, it is relatively more difficult to reduce α through changes in the intensive margin, and, at least in the short-run, difficult to change the extensive margins.[26]

Where federal ownership dominates, states tend to adopt federal rules and royalty policies on state land. This is true in Colorado, Montana, and Wyoming, and likely in other Western states as well. If federal policy changes, we expect states would adapt their policy to match. If state land policies are reactive to federal policy, in-state switching becomes even less likely as any returns from shifting production to state land are reduced.

The state-level average values of α are reported in Table 3. Since α is high for Wyoming (0.9), we do not expect that there will be a substantial shift from extraction on federal land within the state and within the PRB to extraction on state/private land. Other states with a higher average value of α are Colorado (0.7), Montana (0.6), Utah (0.6), and Oklahoma (0.6). The remaining states in our sample have a much lower average value of α and coal producing states not included in our sample have a value of $\alpha = 0$.

Second, substitution across states and basins is unlikely to happen due to inherent differences in the qualities of coal, making coal from different basins imperfect substitutions. For example, coal from the PRB is characterized by a low energy content and low sulfur content compared to coal from other basins. Substituting PRB coal for other types of coal involves substantial switching costs for a coal fired power plant due to asset specificity. The transportation of coal from a mine to a plant is highly specialized and is typically served by one rail line. Plants are also engineered to maximize efficiency conditional on the type of coal used, so switching from PRB coal to Illinois Basin coal would involve substantial conversion costs.[27]

The data used in our analysis indicates that coal fired power plants exhibit a high degree of lock-in to a particular coal basin.[28] Expanding our data to include all coal mines and plants from

[26]Given the large fixed costs associated with coal mining, it is likely that the short-run time horizon is much longer than in other industries.

[27]Joskow (1987) mentions both transportation and conversion costs as two examples of asset specificity in electricity generation.

[28]The lock-in associated with mine/plant relationships is also discussed by Joskow (1985) and Joskow (1987) to

all states (not just states with federal leases), we mapped coal deliveries to each plant in 2014 by the coal basin of origin. We find that 65% of all plants sourced 100% of their coal from one coal basin. In addition, 80% of all plants sourced 80% of their total deliveries from a single coal basin.

One potential reason for a coal fired power plant to be locked in to a particular coal basin is due to asset specificity with respect to maximizing boiler efficiency. If this is the case, the variation in the energy content of coal delivered to a plant should be low. Column 2 in Table 23 lists the mean energy content, measured in Btu/lbs, for coal deliveries to each NERC region. Note that NERC regions in the eastern US (FRCC, NPCC, RFC, and SERC) source relatively less of their coal from the PRB which explains why the coal used in these regions has a higher average energy content. Table 23 also contains the coefficients of variation in the energy content associated with coal deliveries. The third column is the NERC region average coefficient of variation and the fourth column is the average coefficient of variation for each plant within that NERC region. Note that the variation in energy content at the plant level is much lower than the variation at the region level indicating a high degree of asset specificity at the plant level.

5 Conclusion

Our results suggest that changes to federal royalty policy would have a small effect on coal production and delivered prices, but a large revenue benefit to the federal government. These findings are consistent with previous studies on royalties and severance taxes which indicated that royalties and severance taxes are an efficient way to raise revenue. We find that if the ONRR valued coal based on delivered prices net of transportation costs, average total royalty revenues would increase by $141 million per year. The affects of this change on prices and quantities are minimal as we find that the average increase in the delivered price is 23 cents per ton (0.89%) and the decrease in the quantity of coal extracted is 971 thousand tons per year (-0.17%). Severance and income tax collections are expected to decrease by $4 million per year, easily offset by the increase in royalty revenues.

In addition to basing the value of coal on delivered prices, if transportation costs that exceed 50 percent of the value of coal are included in royalty payments, we find that royalty revenues are

explain why long-term contracts are prevalent in this industry.

expected to increase by \$517 million per year. This change would increase the average delivered price of coal by 88 cents per ton (3.36%), decrease the quantity extracted by 3.7 million tons per year (-0.65%), and reduce severance and income tax collections by \$13 million per year. Instead of collecting royalties on transportation costs that exceed a percentage of the delivered price, we find similar effects for collecting royalties on a proportion of transportation costs.

We find evidence of heterogenous impacts across states, with a much larger impact for the PRB states of Wyoming and Montana where more coal is extracted from federal leases and transportation costs are greater. When coal royalties are based on delivered prices, total royalty revenues increase by \$141 million per year with \$139 million resulting from changes in Wyoming and Montana. This represents a 23% increase in royalty revenues from Wyoming and a 45% increase in royalty revenues from Montana.

Our analysis is based at the state-year level and ignores any heterogeneity in coal based on differences in heat and sulfur content. While coal is heterogeneous across coal basins, it is more homogeneous within a basin. Since states usually contain only one coal basin, by focusing our analysis at the state-year level we are able to abstract from differences in the quality of coal. This also allows us to generate overall price/quantity/revenue differences for each state based on the average quality of coal within a state.

As with any study, there are always caveats to the results. The available data from the ONRR describing the federal royalty program lack precision making this assessment difficult. The inferred price for each state is inclusive of deliveries to all markets, including industrial consumers, coke plants, and exports. Since our analysis focuses on the electric power sector, we underestimate the differences between delivered prices and the prices used for royalty valuation. Our underestimate of the price difference results in a downward bias in our estimates of the change in prices, quantities and royalty revenues and is one reason we present confidence intervals for these changes. We also lack precision when determining the expected changes in severance and corporate income taxes, and our results overstate the expected decrease in tax collections.

Another issue is that our estimates are based on the analysis of a static model and does not capture relevant dynamic changes in coal markets resulting from the proposed policy reforms. Due to this limitation, our results are robust only for states where a large share of coal is extracted from federal leases and the extracted coal is an imperfect substitute for coal from other states. This is true for the PRB states of Wyoming and Montana, and we expect our results to be more robust for these states and less robust for other states. Since changes in Wyoming and Montana form the lion's share of our results, our overall analysis is valid.

It is also important to note that our analysis is retrospective as we estimate average annual changes from 2008-2014. With the substantial changes being experienced in coal markets, it would be difficult to use past data to make future, out of sample, predictions. Nevertheless, we would expect the proposed reforms we evaluate to result in a substantial increase in royalty revenue with a minimal effect on coal production and delivered prices, and our analysis highlights the importance of reforming the assessment of federal coal royalties.

A Determination of Expected Values and the Variance

In our analysis, we treat p, Q, T, α,τ_r, ϵ and η as random numbers. Let A be a vector of state-year observations where A includes p, Q, T, α, and τ_r. A statistic of interest is $Z = f(A, \epsilon, \eta)$ where Z may be the change in price, the change in quantity, a change in royalty revenues, or a change in tax collections. If Z is the state-year change in price, we determine Z as the transaction weighted price across the H, M and L groups. Otherwise Z is the sum across the different groups within a state-year.

Here we derive $E[Z]$ and $Var(Z)$ and our derivation excludes subscripts for state-years for simplicity of exposition. Annual variation in A is used to determine the annual expected values and the variance associated with those expected values. The expected values and variances are complicated since we only have point estimates for the expected values and variances of ϵ and η. We assume independence between A, ϵ and η because we lack information on the covariances between A, ϵ and η. In general, these different sets of variables are not expected to be statistically independent.

The expected value of Z is determined using the law of iterated expectations where

$$E[Z] = E_A\Big[E[Z|A]\Big].$$

The $E[Z|A] = E[f(A, \epsilon, \eta)|A]$ and is determined from a second order Taylor series expansion around the expected values where $E[f(A, \epsilon, \eta)|A] = f(A, E[\epsilon], E[\eta]|A)$. Taking the expectation of $f(A, E[\epsilon], E[\eta]|A)$ over A involves computing the annual state-year average.

The variance of Z is decomposed as

$$Var(Z) = E_A[Var(Z|A)] + Var(E[Z|A])$$

and we describe how to determine each term in the above expression. The $Var(E[Z|A])$ is determined from the sample variance of $f(A, E[\epsilon], E[\eta]|A)$ using annual variation. The $Var(Z|A)$ is determined from a second order Taylor series expansion around the expected values where

$$Var(f(A, \epsilon, \eta)|A) = Var(\epsilon)\Big(\frac{\partial f}{\partial \epsilon}\Big)^2 + Var(\eta)\Big(\frac{\partial f}{\partial \eta}\Big)^2.$$

The derivative of $f(\cdot)$ with respect to a change in either ϵ or η is determined from the relevant equation listed in Section 2. We determine $Var(f(A, \epsilon, \eta)|A)$ for each state-year observation and $E_A[Var(f(A, \epsilon, \eta)|A)]$ is determined by taking the sample average of $Var(f(A, \epsilon, \eta)|A)$ over the different years.

B Tables

Table 1: Average Annual Quantities, Prices and Rates Used for Royalty Valuation, 2008-2014

State	Quantity	Price	Statutory Royalty Rate
Alabama	1,463,970	51.73	7.22%
Colorado	18,781,479	42.22	6.14%
Kentucky	181,379	84.03	7.51%
Montana	23,390,340	15.30	11.82%
New Mexico	4,407,583	48.44	5.05%
North Dakota	2,820,951	15.88	2.25%
Oklahoma	607,013	51.67	2.55%
Utah	11,934,524	36.06	6.84%
Wyoming	378,404,640	12.74	12.29%

Note: Quantities are in short tons. Source: ONRR (2015)

Table 2: Average Price of US Coal by Consumer Type, 2008-2012

Consumer Type	2008	2009	2010	2011	2012
Electric Power	40.69	43.33	44.27	46.29	45.77
Commercial/Institutional	86.50	97.28	88.42	91.94	90.76
Coke Plants	118.09	143.01	153.59	184.44	190.55
Industrial, Excluding Coke	63.36	64.87	64.38	70.66	70.33
All Exports	97.68	101.44	120.41	148.86	118.43
Steam Coal Exports	57.35	73.63	65.54	80.42	76.16

Note: Prices are in \$s per short ton. Source: EIA (2015a)

Table 3: Average Annual Values of Q, p, T, and α, 2008-2014

State	Price	Transportation Cost	Quantity	α
Alabama	71.18	18.48	5939	0.076
Colorado	42.34	12.23	20,132	0.696
Kentucky	102.57	24.23	69,197	0.002
Montana	22.03	10.35	25,213	0.558
New Mexico	38.25	5.11	23,044	0.199
North Dakota	16.39	0.73	22,641	0.099
Oklahoma	29.19	4.24	438	0.559
Utah	31.45	11.62	16,994	0.624
Wyoming	15.40	16.10	401,324	0.893

Note: Prices and transportation costs are in US dollars, and quantities are in thousands of short tons. Sources: SNL Financial, ONRR (2015), and MSHA (2015)

Table 4: Average Annual Royalty Rates, 2008-2014

State	Effective Rate	Statutory Rate	Difference
Alabama	5.41%	7.22%	1.81
Colorado	6.04%	6.14%	0.09
Kentucky	6.67%	7.51%	0.84
Montana	8.22%	11.82%	3.60
New Mexico	5.05%	5.05%	0
North Dakota	2.11%	2.25%	0.14
Oklahoma	2.55%	2.55%	0
Utah	6.84%	6.84%	0
Wyoming	10.17%	12.29%	2.12

Sources: ONRR (2015) and SNL Financial

Table 5: State Policy Variables

State	τ_s	τ_s'	State Corporate Income Tax	τ_c
Alabama	0%	0.335	6.5%	25.20%
Colorado	1.74%	0.825	4.6%	23.70%
Kentucky	13.12%	0	6.0%	24.80%
Montana	10.60%	0	6.8%	25.40%
New Mexico	7.90%	0.75	7.3%	25.84%
North Dakota	0%	0.375	4.5%	23.62%
Oklahoma	0%	0	6.0%	24.80%
Utah	1.10%	0	5.0%	24.00%
Wyoming	9.10%	0	0.0%	20.00%

Sources: ONRR (2015), SNL Financial, Haggerty (2015).

Table 6: Price Elasticity of Demand for Coal

NERC Region	ϵ	Standard Deviation
FRCC	-0.5265	0.0599***
MRO	-0.1080	0.0727
NPCC	-0.2273	0.0606***
RFC	-0.1780	0.0336***
SERC	-0.2210	0.0475***
SPP	0.0192	0.0382
TRE	0.0809	0.0521
WECC	-0.1386	0.0312***
US	-0.1107	0.0199***

Note: Standard deviations are in parenthesis. *, **, *** indicate significance at the 10%, 5%, and 1% levels. Source: Hodge (2012)

Table 7: Share Weighed NERC Region Price Elasticity of Demand for Coal

State	ϵ	Standard Deviation
Alabama	-0.2209	0.0475***
Colorado	-0.1688	0.0245***
Kentucky	-0.2452	0.0364***
Montana	-0.1331	0.0307***
New Mexico	-0.1387	0.0311***
North Dakota	-0.1080	0.0727
Oklahoma	0.0000	0.0382
Utah	-0.1411	0.0291***
Wyoming	-0.1132	0.0207***

Note: Standard deviations are in parenthesis. *, **, *** indicate significance at the 10%, 5%, and 1% levels. Sources: Hodge (2012) and SNL Financial.

Table 8: Predicted Revenues in Millions of US Dollars

State	Royalty Revenues	Severance Tax	Income Tax
Alabama	1.81	1.99	19.84
Colorado	35.59	30.58	24.15
Kentucky	0.71	956.89	124.33
Montana	24.75	54.50	7.25
New Mexico	8.68	86.16	21.00
North Dakota	0.81	8.49	15.26
Oklahoma	0.18	0.00	0.59
Utah	21.91	5.57	18.78
Wyoming	560.13	511.12	32.82
Total	653.85	1381.34	222.82

Table 9: Changes in τ_r: Price Effects

State	$E[\Delta p^*]$	Standard Error	$\max \Delta p^*$	$\min \Delta p^*$	$E[\%\Delta p^*]$
Alabama	0.11	0.061	0.12	0.00	0.16%
Colorado	0.02	0.010**	0.03	0.00	0.06%
Kentucky	0.00	0.000*	0.00	0.00	0.00%
Montana	0.42	0.022***	0.46	0.38	1.92%
North Dakota	0.00	0.001**	0.00	0.00	0.01%
Wyoming	0.30	0.036***	0.32	0.23	1.95%
Total	0.23	0.024***	0.25	0.19	0.89%

Note: The changes in prices are in US$. In this table and in subsequent tables, states not effected by the change are excluded. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 10: Changes in τ_r: Quantity Effects

State	$E[\Delta Q^*]$	Standard Error	$\max \Delta Q^*$	$\min \Delta Q^*$	$E[\%\Delta Q^*]$
Alabama	−2028	1176	−4535	0	−0.03%
Colorado	−2538	1317*	−5097	0	−0.01%
Kentucky	−93	35**	−167	−18	0.00%
Montana	−65,515	8423***	−81,883	−49,147	−0.26%
North Dakota	−215	110*	−430	0	0.00%
Wyoming	−900,737	131,784***	−1,156,816	−644,658	−0.22%
Total	−970,519	137,206***	−1,237,136	−703,903	−0.17%

Note: The quantities are short tons. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 11: Changes in τ_r: Revenue Implications

State	ΔRTR	ΔSTR	ΔCITR	%ΔRTR	%ΔSTR	%ΔCITR
Alabama	0.82	0.00	−0.03	45.29%	−0.03%	−0.15%
Colorado	0.62*	0.00*	−0.02*	1.75%	−0.02%	−0.06%
Kentucky	0.05*	0.00*	0.00*	6.95%	0.00%	0.00%
Montana	11.25***	−0.23***	−0.22***	45.47%	−0.43%	−2.98%
North Dakota	0.03**	0.00*	0.00*	4.10%	0.00%	0.00%
Wyoming	128.35***	−1.92***	−1.55***	22.91%	−0.38%	−4.72%
Total	140.88***	−2.16***	−1.80***	21.55%	−0.16%	−0.81%

Note: The change in revenue is in Millions of US$s.

Table 12: Decrease in β to 1: Price Effects

State	$E[\Delta p^*]$	Standard Error	$\max \Delta p^*$	$\min \Delta p^*$	$E[\%\Delta p^*]$
Colorado	0.00	0.000	0.00	0.00	0.00%
Montana	0.05	0.015***	0.06	0.02	0.24%
Utah	0.00	0.000	0.00	0.00	0.00%
Wyoming	0.24	0.049***	0.26	0.15	1.58%
Total	0.18	0.036***	0.19	0.11	0.68%

Note: The changes in prices are in US$. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 13: Decrease in β to 1: Quantity Effects

State	$E[\Delta Q^*]$	Standard Error	$\max \Delta Q^*$	$\min \Delta Q^*$	$E[\%\Delta Q^*]$
Colorado	−33	26	−84	0	0.00%
Montana	−13,053	3760**	−20,359	−5748	−0.05%
Utah	−8	10	−27	0	0.00%
Wyoming	−740,205	132,417***	−997,516	−482,894	−0.18%
Total	−753,300	134,307***	−1,014,282	−492,317	−0.13%

Note: The quantities are short tons. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 14: Decrease in β to 1: Revenue Implications

State	ΔRTR	ΔSTR	ΔCITR	%ΔRTR	%ΔSTR	%ΔCITR
Colorado	0.00	0.00	0.00	0.01%	0.00%	0.00%
Montana	1.38***	−0.03**	−0.03**	5.59%	−0.05%	−0.35%
Utah	0.00	0.00	0.00	0.01%	0.00%	0.00%
Wyoming	100.09***	−1.33***	−1.08***	17.87%	−0.26%	−3.28%
Total	101.48***	−1.36***	−1.10***	15.52%	−0.10%	−0.49%

Note: The change in revenue is in Millions of US$s.

Table 15: Decrease in β to 0.5: Price Effects

State	$E[\Delta p^*]$	Standard Error	$\max \Delta p^*$	$\min \Delta p^*$	$E[\%\Delta p^*]$
Alabama	0.00	0.000	0.00	0.00	0.00%
Colorado	0.03	0.009**	0.03	0.01	0.06%
Montana	0.19	0.025***	0.20	0.14	0.86%
New Mexico	0.01	0.003**	0.01	0.00	0.02%
North Dakota	0.00	0.000*	0.00	0.00	0.00%
Utah	0.06	0.014***	0.06	0.03	0.18%
Wyoming	0.75	0.078***	0.80	0.60	4.87%
Total	0.55	0.057***	0.58	0.44	2.10%

Note: The changes in prices are in US$. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 16: Decrease in β to 0.5: Quantity Effects

State	$E[\Delta Q^*]$	Standard Error	$\max \Delta Q^*$	$\min \Delta Q^*$	$E[\%\Delta Q^*]$
Alabama	−1	1	−4	0	0.00%
Colorado	−2574	952**	−4423	−724	−0.01%
Montana	−42,530	10,743***	−63,406	−21,654	−0.17%
New Mexico	−1162	377**	−1894	−430	−0.01%
North Dakota	−9	5	−20	0	0.00%
Utah	−4851	897***	−6595	−3108	0%
Wyoming	−2,290,016	221,168***	−2,719,785	−1,860,248	−0.57%
Total	−2,341,144	224,291***	−2,776,982	−1,905,306	−0.42%

Note: The quantities are short tons. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 17: Decrease in β to 0.5: Revenue Implications

State	ΔRTR	ΔSTR	ΔCITR	%ΔRTR	%ΔSTR	%ΔCITR
Alabama	0.00	0.00	0.00	0.01%	0.00%	0.00%
Colorado	0.54**	0.00**	−0.02**	1.53%	−0.02%	−0.06%
Montana	5.13***	−0.10***	−0.09***	20.73%	−0.19%	−1.31%
New Mexico	0.19**	0.00**	0.00**	2.15%	0.00%	−0.02%
North Dakota	0.00*	0.00	0.00	0.16%	0.00%	0.00%
Utah	0.93***	0.00***	−0.02***	4.25%	−0.04%	−0.11%
Wyoming	313.41***	−4.35***	−3.51***	55.95%	−0.85%	−10.68%
Total	320.20***	−4.46***	−3.64***	48.97%	−0.32%	−1.63%

Note: The change in revenue is in Millions of US$s.

Table 18: Changes in τ_r and Decrease β to 0.5: Prices and Quantities

State	$E[\Delta p^*]$	$E[\Delta Q^*]$	$E[\%\Delta p^*]$	$E[\%\Delta Q^*]$
Alabama	0.11	−2029	0.16%	−0.03%
Colorado	0.05	−5146	0.12%	−0.03%
Kentucky	0.00	−93	0.00%	0.00%
Montana	0.69	−123,547	3.12%	−0.49%
New Mexico	0.01	−1162	0.02%	−0.01%
North Dakota	0.00	−225	0.01%	0.00%
Utah	0.06	−4851	0.18%	−0.03%
Wyoming	1.18	−3,547,817	7.68%	−0.88%
Total	0.88	−3,684,264	3.36%	−0.65%

Note: The change in prices is in US$ and the change in quantities is in short tons.

Table 19: Changes in τ_r and Decrease β to 0.5: Revenue Implications

State	ΔRTR	ΔSTR	ΔCITR	%ΔRTR	%ΔSTR	%ΔCITR
Alabama	0.82	0.00	−0.03	45.30%	−0.03%	−0.15%
Colorado	1.17	−0.01	−0.03	3.29%	−0.03%	−0.13%
Kentucky	0.05	0.00	0.00	6.95%	0.00%	0.00%
Montana	18.36	−0.37	−0.35	74.17%	−0.69%	−4.79%
New Mexico	0.19	0.00	0.00	2.15%	0.00%	−0.02%
North Dakota	0.03	0.00	0.00	4.27%	0.00%	0.00%
Utah	0.93	0.00	−0.02	4.25%	−0.04%	−0.11%
Wyoming	495.96	−6.97	−5.66	88.54%	−1.36%	−17.24%
Total	517.26	−7.36	−6.09	79.11%	−0.53%	−2.73%

Note: The change in revenue is in Millions of US$s.

Table 20: Increase in γ: Price Effects

State	$E[\Delta p^*]$	Standard Error	$\max \Delta p^*$	$\min \Delta p^*$	$E[\%\Delta p^*]$
Alabama	0.03	0.011*	0.03	0.00	0.04%
Colorado	0.23	0.008***	0.25	0.22	0.55%
Kentucky	0.00	0.001*	0.00	0.00	0.00%
Montana	0.22	0.014***	0.24	0.19	1.00%
New Mexico	0.02	0.007***	0.03	0.01	0.06%
North Dakota	0.00	0.000***	0.00	0.00	0.00%
Oklahoma	0.03	0.003***	0.03	0.02	0.10%
Utah	0.24	0.038***	0.26	0.16	0.76%
Wyoming	0.72	0.050***	0.77	0.63	4.71%
Total	0.54	0.037***	0.58	0.47	2.08%

Note: The changes in prices are in US$. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 21: Increase in γ: Quantity Effects

State	$E[\Delta Q^*]$	Standard Error	$\max \Delta Q^*$	$\min \Delta Q^*$	$E[\%\Delta Q^*]$
Alabama	−543	223*	−1018	−69	−0.01%
Colorado	−20,125	3585***	−27,092	−13,158	−0.10%
Kentucky	−207	98*	−417	0	0.00%
Montana	−44,234	9072***	−61,863	−26,605	−0.18%
New Mexico	−2944	679***	−4263	−1625	−0.01%
North Dakota	−113	40**	−192	−35	0.00%
Oklahoma	0	7	−13	0	0.00%
Utah	−18,672	2298***	−23,136	−14,207	−0.11%
Wyoming	−2,198,874	163,659***	−2,516,893	−1,880,854	−0.55%
Total	−2,285,497	165,181***	−2,606,474	−1,964,519	−0.41%

Note: The quantities are short tons. The maximum and minimum values are the 90% confidence intervals truncated by the theoretical limits.

Table 22: Increase in γ: Revenue Implications

State	ΔRTR	ΔSTR	ΔCITR	%ΔRTR	%ΔSTR	%ΔCITR
Alabama	0.20*	0.00*	−0.01*	11.27%	−0.01%	−0.04%
Colorado	5.14***	−0.04***	−0.13***	14.44%	−0.12%	−0.53%
Kentucky	0.09*	0.00*	0.00*	12.67%	0.00%	0.00%
Montana	5.97***	−0.12***	−0.11***	24.12%	−0.22%	−1.54%
New Mexico	0.59***	−0.01***	−0.01***	6.82%	−0.01%	−0.06%
North Dakota	0.02***	0.00**	0.00**	2.25%	0.00%	0.00%
Oklahoma	0.01***	0.00	0.00	7.20%	0.00%	0.00%
Utah	4.12***	−0.01***	−0.09***	18.81%	−0.16%	−0.48%
Wyoming	304.14***	−4.31***	−3.47***	54.30%	−0.84%	−10.58%
Total	320.20***	−4.49***	−3.82***	48.97%	−0.32%	−1.72%

Note: The change in revenue is in Millions of US$s.

Table 23: Heterogeneity in Coal Deliveries by NERC Region: 2008-2014

NERC Region	Mean Btu/lb	Region Average COV	Average Plant COV
FRCC	12,299	3.7%	3.1%
MRO	8849	7.5%	3.2%
NPCC	11,561	12.2%	3.8%
RFC	11,242	12.8%	6.1%
SERC	11,341	11.4%	3.9%
SPP	8952	6.4%	4.3%
TRE	8224	6.7%	4.0%
WECC	9857	13.6%	3.3%

Note: Btu/lb is the British thermal units per pound of coal and COV is the coefficient of variation. Source: SNL Financial

C Appendix Tables

Table 24: State-Year Effective Royalty Rates

State	2008	2009	2010	2011	2012	2013	2014
Alabama	6.99%	4.74%	6.48%	3.95%			4.88%
Colorado	6.50%	6.69%	6.46%	5.97%	5.60%	5.65%	5.43%
Kentucky			6.30%	6.65%	7.40%	7.38%	5.63%
Montana	8.74%	8.36%	7.73%	7.96%	8.23%	8.24%	8.28%
New Mexico	5.11%	5.00%	5.02%	5.00%	5.00%	5.00%	5.22%
North Dakota	2.18%	2.21%	1.80%	2.20%	2.05%	2.20%	2.13%
Oklahoma	2.41%	2.31%	2.61%	2.84%	2.65%	2.66%	2.34%
Utah	6.43%	6.79%	6.84%	6.85%	6.69%	7.07%	7.21%
Wyoming	9.91%	10.34%	9.68%	9.43%	10.48%	10.79%	10.54%

Sources: ONRR (2015) and SNL Financial

Table 25: State-Year Statutory Royalty Rates

State	2008	2009	2010	2011	2012	2013	2014
Alabama	6.99%	7.05%	7.50%	7.16%	7.09%	7.24%	7.49%
Colorado	6.77%	6.92%	6.55%	6.01%	5.60%	5.69%	5.43%
Kentucky	7.14%	7.53%	7.79%	7.60%	7.52%	7.63%	7.34%
Montana	12.17%	11.99%	11.62%	11.61%	11.63%	11.81%	11.87%
New Mexico	5.11%	5.00%	5.02%	5.00%	5.00%	5.00%	5.22%
North Dakota	2.37%	2.38%	2.20%	2.20%	2.20%	2.20%	2.20%
Oklahoma	2.41%	2.31%	2.61%	2.84%	2.65%	2.66%	2.34%
Utah	6.43%	6.79%	6.84%	6.85%	6.69%	7.07%	7.21%
Wyoming	12.32%	12.33%	12.49%	12.39%	12.14%	12.10%	12.26%

Source: ONRR (2015)

Table 26: State-Group-Year Prices and Transportation Costs

State-Group	Variable	2008	2009	2010	2011	2012	2013	2014
Alabama M	p	44.33						
	T	22.46						
Alabama L	p		65.56	73.62	85.04			87.33
	T		14.18	16.87	19.65			19.25
Colorado H	p		12.63			30.62	12.15	
	T		12.63			38.39	15.56	
Colorado M	p	34.15	40.50	38.18	32.98	53.89	44.99	39.53
	T	20.04	23.20	22.18	19.68	30.94	28.33	25.24
Colorado L	p	35.70	39.69	43.32	46.09	45.93	42.61	43.94
	T	10.10	9.53	10.11	10.98	10.85	8.94	9.01
Kentucky	p			121.38	136.13	88.88	82.33	84.13
	T			21.78	22.89	26.48	26.09	23.92
Montana H	p	10.92	10.86	11.87	11.83	14.89	13.77	14.09
	T	13.82	14.63	13.97	14.78	18.77	20.15	20.25
Montana M	p	16.91	22.73	20.58	25.49	28.16	28.44	27.65
	T	14.60	15.77	14.04	15.51	19.65	17.80	18.18
Montana L	p	22.94	21.78	25.71	25.57	24.20	32.86	37.89
	T	0.68	0.65	1.75	1.63	0.62	0.19	0.04
New Mexico M	p	14.95	18.56	20.40	20.60	21.27	21.60	20.44
	T	10.83	13.26	13.72	11.18	13.82	14.57	16.19
New Mexico L	p	34.47	38.90	45.46	46.04	48.85	49.75	40.58
	T	5.09	5.94	0.89	0.03	0.06	0.86	5.75
North Dakota M	p	10.36	13.93	13.95		15.40	14.93	15.22
	T	6.82	7.44	7.18		9.56	10.81	11.01
North Dakota L	p	13.15	13.58	15.31	16.64	17.78	19.08	19.39
	T	0.74	0.47	0.57	0.49	0.57	0.78	0.85
Oklahoma	p	23.34	27.67	30.00	26.25	29.88	32.42	34.76
	T	3.66	3.47	2.96	3.22	4.99	5.71	5.67
Utah H	p		20.30			27.78		
	T		24.35			33.01		
Utah M	p	25.85	23.21	20.73	22.19	25.57	27.09	28.50
	T	15.96	15.37	13.42	13.72	16.08	17.31	20.61
Utah L	p	26.65	32.54	36.03	38.30	37.89	36.16	34.58
	T	8.37	10.40	9.42	8.61	8.74	9.32	9.92
Wyoming H	p	11.71	11.66	11.99	13.07	14.50	14.37	14.62
	T	14.73	15.45	15.06	15.81	18.44	19.89	20.01
Wyoming M	p	16.69	18.24	17.65	19.70	21.62	19.34	17.91
	T	13.53	14.28	13.82	15.11	17.67	15.96	14.41
Wyoming L	p	22.99	25.25	26.05	30.48	31.30	29.60	37.25
	T	3.41	3.28	4.90	4.32	2.19	2.60	1.59

Note: Annual prices and transportation costs are determined only from federal leases and are production weighted. Consistent with the model, p is the price and T is the transportation cost. Source: SNL Financial

Table 27: State-Group-Year Quantities

State-Group	2008	2009	2010	2011	2012	2013	2014
Alabama M	6907						
Alabama L		5721	6723	7086			3259
Colorado H		12			105	24	
Colorado M	8686	2154	238	297	1695	3314	5339
Colorado L	19,744	21,123	19,570	20,023	14,867	12,290	11,444
Kentucky			79,058	80,708	69,287	59,006	57,925
Montana H	15,157	7995	3269	2850	3860	7971	10,569
Montana M	10,033	11,547	12,015	10,816	6914	2861	1663
Montana L	11,594	9224	12,487	10,160	8344	9129	8030
New Mexico M	1228	4392	3553	4466	8071	7505	3854
New Mexico L	22,498	21,299	18,502	20,462	14,650	14,540	16,285
North Dakota M	196	551	1		457	432	106
North Dakota L	23,276	23,544	23,158	21,704	21,617	21,589	21,852
Oklahoma	570	337	343	381	457	487	493
Utah H		91					
Utah M	7617	5997	4209	3665	6604	6821	4040
Utah L	14,588	14,031	13,756	12,801	7965	7714	9061
Wyoming H	286,541	284,239	173,106	193,281	325,939	331,903	329,079
Wyoming M	98,804	125,231	219,287	205,613	57,205	24,383	27,329
Wyoming L	21,909	18,016	22,751	18,004	16,165	17,567	12,917

Note: Quantities are in thousands of short tons.

Source: SNL Financial

Table 28: State-Year Values for α

State	2008	2009	2010	2011	2012	2013	2014
Alabama	0.009	0.070	0.127	0.141	0.120	0.053	0.013
Colorado	0.704	0.636	0.727	0.719	0.669	0.709	0.710
Kentucky	0.003	0.002	0.000	0.001	0.003	0.003	0.000
Montana	0.587	0.607	0.558	0.542	0.640	0.493	0.481
New Mexico	0.161	0.126	0.130	0.167	0.210	0.267	0.330
North Dakota	0.121	0.035	0.008	0.076	0.142	0.143	0.168
Oklahoma	0.515	0.636	0.587	0.554	0.428	0.535	0.661
Utah	0.555	0.465	0.576	0.357	0.786	0.834	0.795
Wyoming	0.880	0.937	0.894	0.887	0.932	0.870	0.852

Sources: ONRR (2015) and MSHA (2015).

Table 29: Share Weighed NERC Region Price Elasticity of Demand for Coal

State	ϵ	Standard Deviation
Alabama L	−0.2210	0.0475***
Alabama M	−0.2209	0.0474***
Colorado H	−0.2059	0.0392***
Colorado L	−0.1618	0.0245***
Colorado M	−0.2020	0.0343***
Kentucky	−0.2452	0.0364***
Montana H	−0.1266	0.0428**
Montana L	−0.1377	0.0290***
Montana M	−0.1334	0.0398***
New Mexico L	−0.1387	0.0311***
New Mexico M	−0.1386	0.0312***
North Dakota L	−0.1080	0.0727
North Dakota M	−0.1082	0.0724
Oklahoma	0.0000	0.0382
Utah H	−0.1082	0.0726
Utah L	−0.1400	0.0294***
Utah M	−0.1434	0.0287***
Wyoming H	−0.1042	0.0215***
Wyoming L	−0.1406	0.0262***
Wyoming M	−0.1313	0.0211***

Note: Standard deviations are in parenthesis. *, **, *** indicate significance at the 10%, 5%, and 1% levels. Sources: Hodge (2012) and SNL Financial.

References

Alt, C. B., Baumann, M. G., & Zimmerman, M. B. (1983). The economics of western coal severance taxes. *The Journal of Business*, *56*(4), 519–536.

Beck, T., Jolly, L., & Loncar, T. (1991). *Supply response in the Australian black coal industry* (No. 91.1). Canberra, Australia: Australian Board of Agricultural and Resource Economics.

Bernstein, M. A., & Griffin, J. (2006, February). *Regional differences in the price-elasticity of demand for energy.* Santa Monica, CA: RAND Corporation.

Chakravorty, U., Gerking, S., & Leach, A. (2010). State tax policy and oil production. *US Energy Tax Policy*, 759–774.

Dahl, C., & Duggan, T. E. (1996). US energy product supply elasticities: A survey and application to the US oil market. *Resource and Energy Economics*, *18*(3), 243–263.

Dahl, C., & Ko, J. (1998). The effect of deregulation on US fossil fuel substitution in the generation of electricity. *Energy policy*, *26*(13), 981–988.

Deacon, R. T. (1993). Taxation, depletion, and welfare: A simulation study of the US petroleum resource. *Journal of environmental economics and management*, *24*(2), 159–187.

EIA. (2001, July). *Coal market module of the national energy modeling system: Model documentation 2001.* Washington, DC: US Energy Information Administration, US Department of Energy.

EIA. (2014, July). *Coal market module of the national energy modeling system: Model documentation 2014.* Washington, DC: US Energy Information Administration, US Department of Energy.

EIA. (2015a). *Coal data browser.* Washington, DC: US Energy Information Administration, US Department of Energy. Retrieved from `http://www.eia.gov/beta/coal/data/browser/` ([Online; accessed 30-April-2015])

EIA. (2015b). *Nems documentation.* Washington, DC: US Energy Information Administration, US Department of Energy. Retrieved from `http://www.eia.gov/forecasts/aeo/nems/documentation/` ([Online; accessed 2-April-2015])

Gamponia, V., & Mendelsohn, R. (1985). The taxation of exhaustible resources. *The Quarterly Journal of Economics*, *100*(1), 165–181.

GAO. (2013). *Coal leasing: BLM could enhance appraisal process, more explicitly consider coal exports, and provide more public information* (GAO Publication No. 14-140). Washington, DC: Government Accountability Office. Retrieved from `http://www.gao.gov/products/gao-14-140`

Haggerty, M. (2015, April). *An assessment of US federal coal royalties.* Bozeman, MT: Headwaters Economics.

Hodge, T. (2012, June). *Fuel competition in power generation and elasticities of substitution.* Washington, DC: US Energy Information Administration, US Department of Energy.

Humphries, M., & Sherlock, M. F. (2013). *U.S. and world coal production, federal taxes, and incentives* (CRS Report R43011). Washington, DC: Congressional Research Service. Retrieved from `http://fas.org/sgp/crs/misc/R43011.pdf` ([Online; accessed 22-December-2014])

Joskow, P. L. (1985). Vertical integration and long-term contracts: The case of coal-burning electric generating plants. *Journal of Law, Economics, & Organization*, *1*(1), 33–80.

Joskow, P. L. (1987). Contract duration and relationship-specific investments: Empirical evidence from coal markets. *The American Economic Review*, *77*(1), 168–185.

Ko, J., & Dahl, C. (2001). Interfuel substitution in US electricity generation. *Applied Economics*, *33*(14), 1833–1843.

Kolstad, C. D., & Wolak, J., Frank A. (1983). Competition in interregional taxation: The case of western coal. *Journal of Political Economy*, *91*(3), 443–460.

Kolstad, C. D., & Wolak, J., Frank A. (1985). Strategy and market structure in western coal taxation. *The Review of Economics and Statistics*, *67*(2), 239–249.

Kunce, M. (2003). Effectiveness of severance tax incentives in the US oil industry. *International Tax and Public Finance*, *10*(5), 565–587.

Kunce, M., Gerking, S., & Morgan, W. (2004). Environmental and land use regulation in nonrenewable resource industries: Implications from the Wyoming checkerboard. *Land Economics*, *80*(1), 76–94.

Kunce, M., Gerking, S., Morgan, W., & Maddux, R. (2003). State taxation, exploration, and production in the US oil industry. *Journal of Regional Science*, *43*(4), 749–770.

MSHA. (2015). *Quarterly mine employment and coal production report.* Washington, DC: US Department of Labor, Mine Safety and Health Administration. Retrieved from `http://`

www.msha.gov/OpenGovernmentData/OGIMSHA.asp ([Form 7000-2])

ONRR. (2015). *Reported revenue data.* Washington, DC: US Department of the Interior, Office of Natural Resource Revenue. Retrieved from http://statistics.onrr.gov/ ([Online; accessed 30-April-2015])

Ranck, E. L. (1985). On the incidence of ad valorem severance taxes. *National Tax Journal*, *38*(2), 241–245.

Rowse, J. (1997). On ad valorem taxation of nonrenewable resource production. *Resource and energy economics*, *19*(3), 221–239.

Yücel, M. K. (1986). Dynamic analysis of severance taxation in a competitive exhaustible resource industry. *Resources and Energy*, *8*(3), 201–218.

Yücel, M. K. (1988). Severance tax shifting: A quantitative analysis. *Resources and energy*, *10*(3), 265–275.

Yücel, M. K. (1989). Severance taxes and market structure in an exhaustible resource industry. *Journal of Environmental Economics and Management*, *16*(2), 134–148.