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FEDERAL COAL PROGRAM REFORM, THE CLEAN POWER PLAN, AND THE INTERACTION OF UPSTREAM AND DOWNSTREAM CLIMATE POLICIES

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ABSTRACT

Coal mined on federally managed lands accounts for approximately 40% of U.S. coal consumption and 13% of total U.S. energy-related CO2 emissions. The U.S. Department of the Interior is undertaking a programmatic review of federal coal leasing, including the climate effects of burning federal coal. This paper studies the interaction between a specific upstream policy, incorporating a carbon adder into federal coal royalties, and downstream emissions regulation under the Clean Power Plan (CPP). After providing some comparative statics, we present quantitative results from a detailed dynamic model of the power sector, the Integrated Planning Model (IPM). The IPM analysis indicates that, in the absence of the CPP, a royalty adder equal to the social cost of carbon could reduce emissions by roughly 3/4 of the emissions reduction that the CPP is projected to achieve. If instead the CPP is binding, the royalty adder would: reduce the price of tradeable emissions allowances, produce some additional emissions reductions by reducing leakage, and reduce wholesale power prices under a mass-based CPP but increase them under a rate-based CPP. A federal royalty adder increases mining of non-federal coal, but this substitution is limited by a shift to electricity generation by gas and renewables.

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A Detailed IPM simulation results is available at
http://www.vulcan.com/MediaLibraries/Vulcan/Documents/Federal-Coal-Lease-Model-report-Jan2016.pdf

1. Introduction

Approximately 40% of the coal burned in the United States is mined on federally managed land under a minerals leasing program administered by the U.S. Department of the Interior (DOI). This federal coal accounts for approximately 13% of all U.S. energy-related emissions of carbon dioxide. Citing both climate concerns and problems with the mineral leasing program obtaining a fair value for the taxpayer (e.g., DOI Office of the Inspector General (2013), General Accounting Office (2014)), on January 15, 2016 the Department of the Interior announced it would undertake a comprehensive programmatic review of the coal leasing program. As it did in previous comprehensive reviews, DOI imposed a partial moratorium on new coal leases for the duration of the review. The scope of the programmatic review, as clarified in a Notice of Intent issued March 24, 2016, includes the climate impact of burning federal coal. The policy options available to the Department of the Interior include reducing the quantity of federal coal produced under new leases and adjusting federal royalties to reflect the climate costs imposed by burning that coal.

This paper studies the impacts on the power sector of a specific upstream policy: incorporating a carbon adder into the royalty on federal coal. The paper focuses on two key issues. First, because most U.S. coal is produced under mineral rights owned by entities other than the federal government, there could be substitution from federal coal to non-federal coal. Second, because the predominant use of coal is for electricity generation, this upstream regulation would coexist with downstream regulation of the power sector through the Clean Power Plan (CPP). Because of non-federal coal alternatives upstream, and emissions regulation downstream, in theory a federal carbon adder could merely serve to redistribute coal revenues while having modest or negligible climate impacts.

We examine the interactions between a federal royalty carbon adder, the availability of non-federal coal substitutes, and downstream regulation via the CPP using two distinct modeling strategies. First, we use a highly stylized static model of the power sector to illustrate these interactions as transparently as possible. Because this model is far too simple to provide meaningful quantitative estimates, we then turn to a detailed dynamic model of the power sector, the Integrated Planning Model (IPM) maintained by ICF International. The IPM is a proprietary model that is widely used for industry and environmental analysis; for example, the IPM was used by the EPA's Regulatory Impact Analysis of the CPP (EPA 2015). Our aim in using these two modeling strategies is first to elucidate the qualitative effects of a royalty adder on federal coal and second to provide plausible numerical estimates of its effects under assumptions that closely mimic current policy possibilities.

Because the legal fate of the CPP is currently unknown, and because the CPP final rule provides states with both mass- and rate-based compliance options, we develop the stylized static model under various versions of downstream regulation. With no downstream regulation (or if downstream regulation is not binding), the royalty adder reduces CO_2 emissions; the extent to which non-federal coal attenuates those reductions depends on the supply elasticities of non-federal coal and lower-emitting non-coal power sources. With a binding textbook mass-based cap-and-trade system, a carbon adder on federal coal changes the fuel mix but does not change emissions. The increase in the relative price of coal changes the generation mix to cleaner sources (e.g. natural gas), producing more output for the same emissions, which in turn drives down the price of electricity and increases consumption. The price of tradable emissions permits falls, so the compliance cost of the downstream policy is partially borne by the upstream policy.

The CPP could have either rate- or mass-based compliance, and neither would cover all electricity generators, so we extend the textbook cap-and-trade model in two ways. First, we allow for leakage to uncovered electricity generators under mass-based regulation. Leakage does not change the qualitative effects of the carbon adder on prices and covered sources, but the carbon adder reduces leakage of the mass-based policy. Under rate-based downstream regulation with leakage, the carbon adder increases the price of electricity and reduces the price of the tradeable permit, so again the carbon adder bears some of the compliance cost of the downstream regulation. Whether emissions increase or decrease is ambiguous in general and depends on the response of demand and of uncovered generation to the higher electricity price.

The IPM simulations provide quantitative estimates of the effects of a federal royalty adder. The royalty adder is phased in over 10 years to simulate its application to new, modified, and renewed leases but not to existing leases. The baseline assumptions used here are calibrated to match the baseline in the EPA's (2015) Regulatory Impact Analysis of the CPP. The simulations examine the effect of a royalty adder under three versions of upstream regulation: no CPP, mass-based implementation, and rate-based implementation. The mass- and rate-based regulation implement two different compliance options laid out in the 2015 CPP final rule.

Specifically, the mass-based version brings new fossil fuel sources under the cap (with some exceptions) and allows for regional trading of emissions allowances. The rate-based version covers only existing fossil sources, which must satisfy a state-level rate condition with regional trading, while new and modified fossil fuel sources are subject to separate rate regulation.

The IPM runs provide six main findings. First, in the absence of downstream regulation (no CPP), a carbon adder applied to federal coal results in limited substitution of non-federal coal: most of the fuel switching is to natural gas and renewables, reducing CO_2 emissions. For example, without the CPP, an adder equal to the U.S. Government estimate of the Social Cost of Carbon is estimated to reduce power sector CO_2 emissions by nearly three-quarters the estimated reduction from the CPP without a carbon adder. Second, even with the strong mass-based CPP in place, a federal royalty adder drives additional emissions reductions because of reduced leakage and because, in some regions, the IPM simulations indicate that by 2030 the CPP would not be binding in the presence of a royalty adder. Third, emissions reductions induced by a federal coal carbon adder on top of a rate-based CPP are larger than those induced by the carbon adder on top of mass-based CPP. Fourth, in both the mass- and rate-based versions, the royalty adder increases non-federal coal production, relative to the no-adder case. Fifth, under both rate- and mass-based CPPs, the price of tradeable emissions allowances falls as the adder increases, so the federal carbon adder decreases the cost of compliance with the CPP. Sixth, total royalty receipts, which are split between the federal government and the state in which the coal is mined, increase sharply with the carbon adder, even though federal coal production declines.

This paper contributes to a large theoretical literature on instrument choice and overlapping policies. Holland (2012) studies the relative efficiency of mass- and rate-based regulation and shows that emissions leakage can provide an efficiency rationale for rate-based regulation. Mansur (2012) uses a theoretical model to highlight the key factors that determine optimal vertical targeting of regulation (i.e., upstream or downstream). Goulder and Stavins (2012) assess the effects of overlapping state and federal cap-and-trade policies. They highlight the potential for stringent sub-national policies to induce emissions leakage to covered sources in other states, compromising national cost-effectiveness without inducing any net emissions reductions.[1] Goulder, Jacobsen, and van Benthem (2012) demonstrate the relevance of these

[1] Fankhauser et al. (2010) make similar points with an emphasis on the European policy context.

theoretical points in a study of the vehicle market. Fischer and Newell (2008) and Fischer, Newell, and Preonas (2013) investigate the welfare impacts of introducing alternative regulatory instruments that overlap with comprehensive greenhouse gas regulation but have the potential to address additional market failures (e.g., innovation market failures).[2] Horowitz and Linn (2015) highlight the potentially perverse impact of technological change in the presence of rate-based regulation, where cost reductions for clean energy can lead to increases in total emissions. In contrast to these previous papers, we study the interaction of overlapping upstream and downstream policies, both with partial coverage, with a particular focus on the effect of leakage on electricity market and emissions outcomes. This paper is also related to Harstad (2012) in that both consider supply-side policies in the presence of downstream policies; however, Harstad's (2012) focus is on supply restriction for unregulated fuels (in his setting, fossil fuels in countries not participating in an international climate agreement) whereas here we consider supply-side policies for fuels with regulated emissions.

This paper also contributes to the new literature on the economics of the CPP. Bushnell et al. (2015) look at interactions between rate and mass plans under the proposed CPP; the analysis here considers either rate- or mass-based implementation, using the final CPP rule, and introduces upstream regulation. The literature on the federal coal program is small; notable contributions are Krupnick et al. (2015), who examine the legal framework for a carbon adder on federal coal, and Hein and Howard (2015), who consider both fair return and climate concerns about the federal coal program. In this literature, the paper most closely related to ours is Haggerty, Lawson, and Pearcy (2015), who use a partial equilibrium model of the coal market to estimate the effect on coal revenues and prices of changing the method for computing coal revenues to be gross of transport costs.

The remainder of the paper is organized as follows. Section 2 provides a brief summary of the federal coal program. Section 3 presents the comparative statics. Section 4 lays out the research design using the IPM model, and Section 5 presents the IPM results. Section 6 concludes.

[2] See Fischer and Preonas (2010) for a review of further literature on this topic.

2. The Federal Coal Program[3]

In 2014, U.S. coal production was 1.00 billion short tons, of which approximately 42% was mined on federally managed lands. U.S. 2014 coal net exports were 86 million tons, most of which was metallurgical coal. Approximately 93% of coal consumption in the United States is to produce steam for generating electricity. Burning coal (federal and non-federal) accounted for approximately 1.7 billion metric tons of CO_2 emissions in 2014, roughly one third of all CO_2 emissions from fossil fuels.[4]

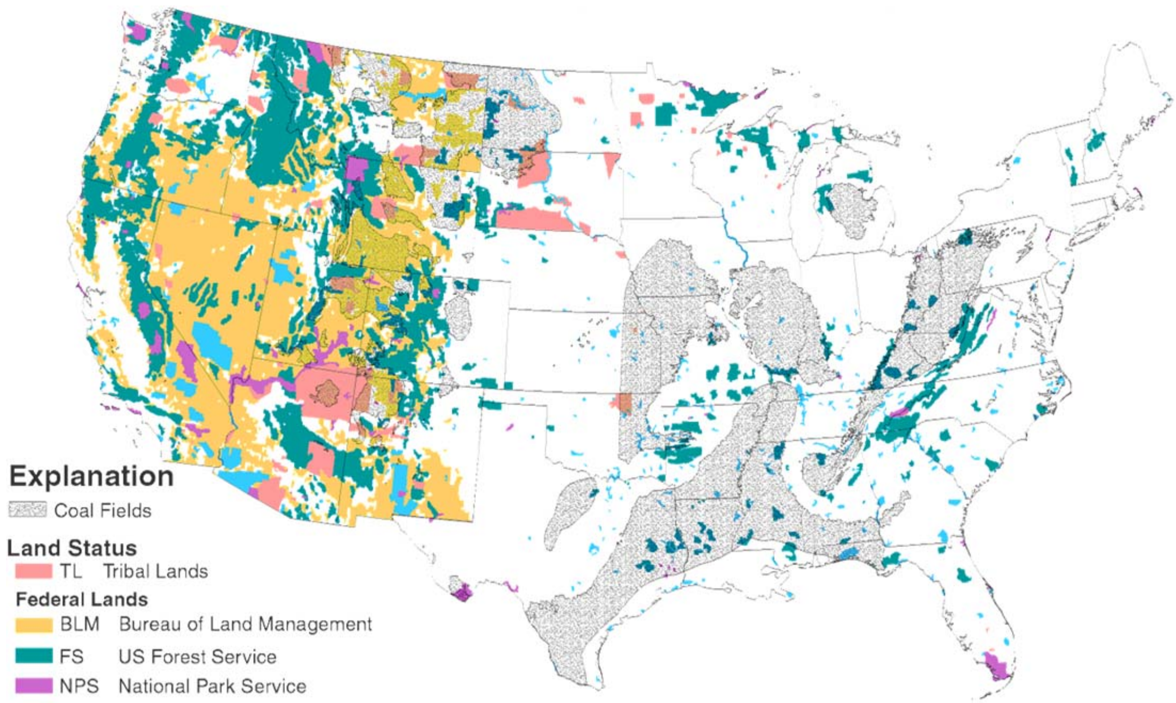
As shown in Figure 1, nearly all federal coal deposits are in western states. Wyoming, Montana, Colorado, and Utah together account for 94% of coal mined on federal and Indian lands (Table 1). The single largest basin for U.S. coal production is the Powder River Basin (PRB) in Wyoming and Montana. Figure 2 shows coal production by region from 2001-2013. In federal fiscal year 2014, 364 million short tons were produced on federal lands in Montana and Wyoming, 93 percent of which was in Wyoming (see Table 1).

Most but not all of the mineral rights in the PRB are federal. State mineral rights, and some tribal and private rights, are typically checkerboarded inholdings surrounded by land with federal rights. PRB mines are large surface mines that use massive drag line technology in a manner that follows seams, often across land with different owners of mineral rights. A mine that spans federal and other tracts is generally consolidated into a logical mining unit that allows for continuity in operations across the federal and other tracts when coal seams cross property boundaries.

[3] This section provides a brief overview of coal production and the federal coal program. For more detail, see the summary in U.S. DOI Office of the Inspector General (2013) and in Krupnick et al. (2015).

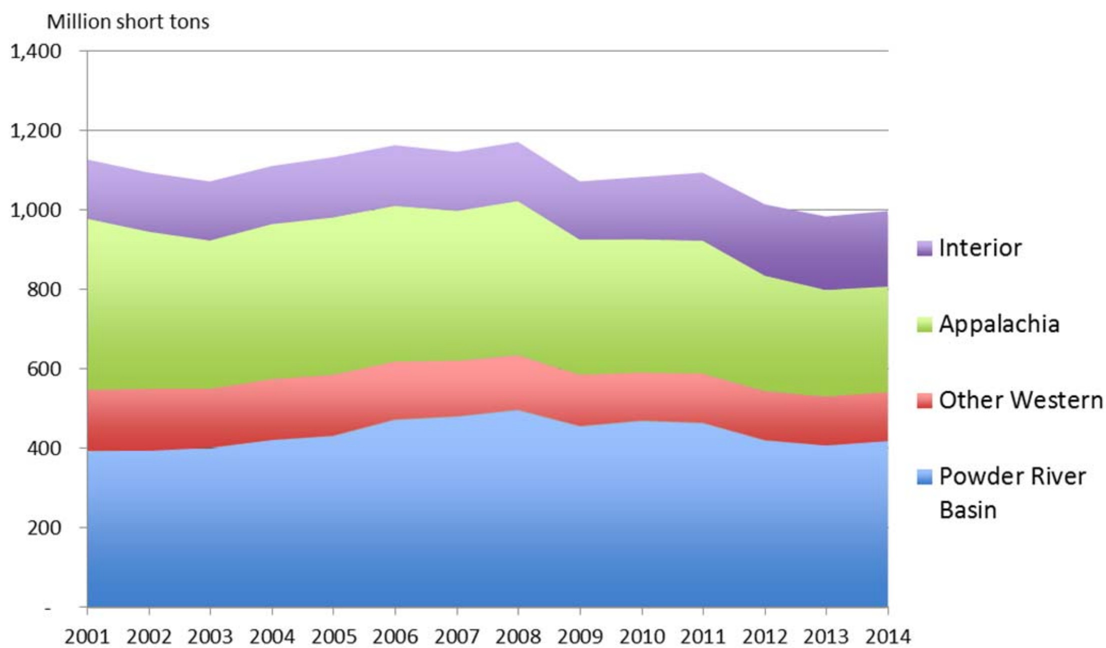
[4] Total production in 2013 was 984.8 million short tons and in 2014 was 999.7 million short tons (U.S. Energy Information Administration (EIA) (2016a), *Short Term Energy Outlook*, February 2016, Table 6). Federal coal production is measured by Federal fiscal year, which is Oct. 1 – Sept. 30 and was 421 million short tons in FY 2014 (EIA 2015, *Sales of Fossil Fuels Produced from Federal and Indian Lands FY2003 through FY 2014*, Table 11). Using a weighted average of the calendar year total production yields a federal coal percentage of 42.3%. Coal consumption data are from EIA (2016a). Federal coal emissions are computed as 42.3% of the 31.7% of the energy-related CO_2 emissions due to burning coal in 2014 (EIA 2016b, *Monthly Energy Review*, Table 12.1). Also see EIA (2016c). Source for coal production and consumption data: EIA, Coal Data Browser, at https://www.eia.gov/beta/coal/data/browser/.

Figure 1. U.S. Coal Deposits and Federal Lands



Source: U.S.G.S. at http://pubs.usgs.gov/of/1997/ofr-97-0461/lands2.html

Figure 2
U.S. Coal Production by Region



Source: Energy Information Administration, Coal Data Browser

Table 1.
Annual Federal and Non-Federal Coal Production (millions of short tons)

State	Total, 2013	Total, 2014	Federal only, FY2014	Federal percent
Wyoming	388	396	337	86%
Montana	42	45	27	61%
Colorado	24	24	17	71%
Utah	18	17	14	81%
Other	526	502	26	5%
Total	998	983	421	43%

Sources: EIA (2015, 2016a). Federal percent is computed as the ratio of FY production to the weighted average of calendar year 2013 and 2014 production, weighted by the fractions of the calendar year in the fiscal year. Excludes refuse recovery.

Powder River Basin coal is low-sulfur and primarily sub-bituminous coal. PRB coal enjoys a considerable price advantage over coal from other basins, especially Appalachian coal. For example, in 2014 the average mine-mouth sales price of coal was $14 per short ton in Wyoming, $58 in Kentucky, and $71 in southern West Virginia.[5] One reason for this difference in mine-mouth prices is mining costs. Most eastern coal is mined underground, which is labor intensive: average productivity for West Virginia mines in 2012 was 2.4 short tons per worker-hour, a rate typical for Appalachian states. In contrast, PRB coal is surface-mined and highly mechanized, with productivity of 27 short tons per worker-hour – productivity an order of magnitude higher than Appalachian coal mines. Because of this higher productivity, in 2012 total coal mine employment in Wyoming was 7,000 and in Montana was 1,200, whereas total coal mine employment in West Virginia was 22,800, even though coal production in Wyoming and Montana was 438 million short tons compared with 120 million short tons in West Virginia.[6]

Under the Mineral Leasing Act of 1920 as amended by the Federal Coal Leasing Amendments Act of 1976, the U.S. Department of Interior collects royalties on production of coal and other minerals on Federal land, and forwards approximately half of these royalty revenues to states. By law the minimum royalty rate on surface-mined coal is 12.5% of the sales

[5] EIA, *Annual Coal Report* 2014, Table 28.
[6] Source for the productivity and employment data is EIA, *Coal Data Browser* at http://www.eia.gov/beta/coal/data/browser/.

price, and the royalty rate on underground mines was set by regulation at 8% in 1990. The Bureau of Land Management typically sets royalties at the minimum rate prescribed by law (U.S. GAO 2013), and also frequently exercises its authority to issue partial royalty waivers. Reviews by the U.S. government and externally suggest that actual royalty payments are further reduced by failure to measure accurately arms-length mine-mouth prices (U.S. General Accounting Office 2015, U.S. DOI 2014). Haggerty and Haggerty (2015) estimate the effective royalty rate on federal coal to be as low as 5%. A substantial amount of the recent work on reform of the federal coal program has focused on obtaining a fair return to the taxpayer.

It appears that the DOI has wide discretion in setting royalty rates for new or renewed leases.[7] Krupnick et al. (2015) examines the legal basis for changing federal royalties administratively and conclude (subject to caveats) that DOI has the statutory and regulatory authority to impose a carbon charge via the royalty rate.

In 2016, the DOI announced that it would undertake a programmatic review of its coal leasing program in the form of a Programmatic Environmental Impact Statement. The DOI's Notice of Intent indicated that the scope of the review includes climate considerations of burning federal coal, and that policy options include limiting federal coal leases and adjusting royalties to incorporate climate externalities.[8]

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[7] Title 30, Section 207 of the U.S. Federal Code states conditions on federal leases. Clause (a) Term of lease; annual rentals; royalties; readjustment of conditions states:

> A coal lease shall be for a term of twenty years and for so long thereafter as coal is produced annually in commercial quantities from that lease. Any lease which is not producing in commercial quantities at the end of ten years shall be terminated. The Secretary shall by regulation prescribe annual rentals on leases. A lease shall require payment of a royalty in such amount as the Secretary shall determine of not less than 12 1/2 per centum of the value of coal as defined by regulation, except the Secretary may determine a lesser amount in the case of coal recovered by underground mining operations. The lease shall include such other terms and conditions as the Secretary shall determine. Such rentals and royalties and other terms and conditions of the lease will be subject to readjustment at the end of its primary term of twenty years and at the end of each ten-year period thereafter if the lease is extended.

[8] The Secretarial Order announcing the moratorium and PEIS was issued January 15, 2016 (http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.4909.File.dat/SO%203338%20Coal.pdf). The March 24, 2016 NOI section on the scope of the review in the context of climate change reads in part:

> … [The PEIS] will also consider whether and how to mitigate, account for, or otherwise address those impacts through the structure and management of the coal program, including, as appropriate, land use planning, adjustments to the scale and pace of leasing, adjustments to royalties or other means of internalizing externalities, mitigation through greenhouse gas reductions elsewhere, information disclosure, and other approaches… (81 FR 17725 at https://www.gpo.gov/fdsys/pkg/FR-2016-03-30/pdf/2016-07138.pdf).

3. A Static Model of Partial Upstream and Downstream Regulation

We begin our analysis of the effects of a federal coal carbon adder with a stripped-down static partial equilibrium model of electricity production. We examine the effect of a carbon adder on the electricity price, production by source, total electricity production (consumption), emissions, welfare, and (as applicable) the price of tradable emissions permits. We also derive the static welfare-maximizing value of the carbon adder. We stress that the purpose of this exercise is to develop intuition in a very simple setting; the setup is far too simple to provide quantitative estimates for policy.

In our model, electricity can be generated by federal coal (*FC*), by non-federal coal (*NFC*), or by other sources (*O*). Federal and non-federal coal are assumed to have the same CO_2 emissions rate per MWh of generation, whereas the other sources are assumed to have a lower emissions rate which is a fraction λ of the emissions rate of coal; think of "other" as natural gas.[9] When we introduce downstream regulation with partial coverage, we introduce a fourth fuel which is not covered by the regulation, uncovered generation (*U*), which has an emissions rate λ_U that is lower than coal but not necessarily the same as the other covered sources. Once generated, we model electricity as homogenous.

Throughout, we model electricity demand as arising from a money metric utility function that has two components: utility from electricity consumption and utility from all other consumption. We abstract from income effects. The utility from electricity consumption is increasing and is weakly concave so that the electricity demand curve weakly slopes down. Throughout we also assume that all marginal cost curves are weakly increasing in output, that at least one of the supply curves is strictly increasing, and that all quantities are positive in equilibrium.

To develop intuition, we begin with a graphical treatment in which there are at most two other fuels, and in which there is either no downstream regulation or a binding cap-and-trade system with no uncovered sources. We then turn to the formal comparative statics for three

[9] Coal varies substantially in percent carbon content, ash content, sulfur content, hardness, and in many other ways, so CO_2 emissions per ton of coal burned varies considerably across coal rank. However, because the energy content of coal comes from burning the carbon in the coal, CO_2 emissions per unit of energy are similar across varieties of steam coal. For example, averages for bituminous, subbituminous, and lignite are 205.7, 214.3, and 215.4 pounds of CO_2 per million Btu of energy, compared with 117.0 for natural gas (EIA at https://www.eia.gov/environment/emissions/co2_vol_mass.cfm).

versions of downstream regulation with multiple fuels: no downstream regulation, mass-based cap-and-trade with tradeable allowances and uncovered sources, and rate-based regulation with tradable allowances and uncovered sources. As discussed below, the two cases with leakage provide a simple representation of the uncovered sources that are present (although different) under the mass- and rate-based implementation options in the CPP final rule.

3.1. Intuition: Two Fuels and a Royalty Adder

We begin with a graphical treatment to develop intuition. All results depicted here follow from the equations presented in Sections 3.2 – 3.4. Let p and Q denote the price and quantity of electricity, and let r denote the effect of the royalty adjustment on the marginal cost of electricity generators using federal coal, priced in the units of p (e.g., \$/MWh); we refer to r as the carbon adder.[10]

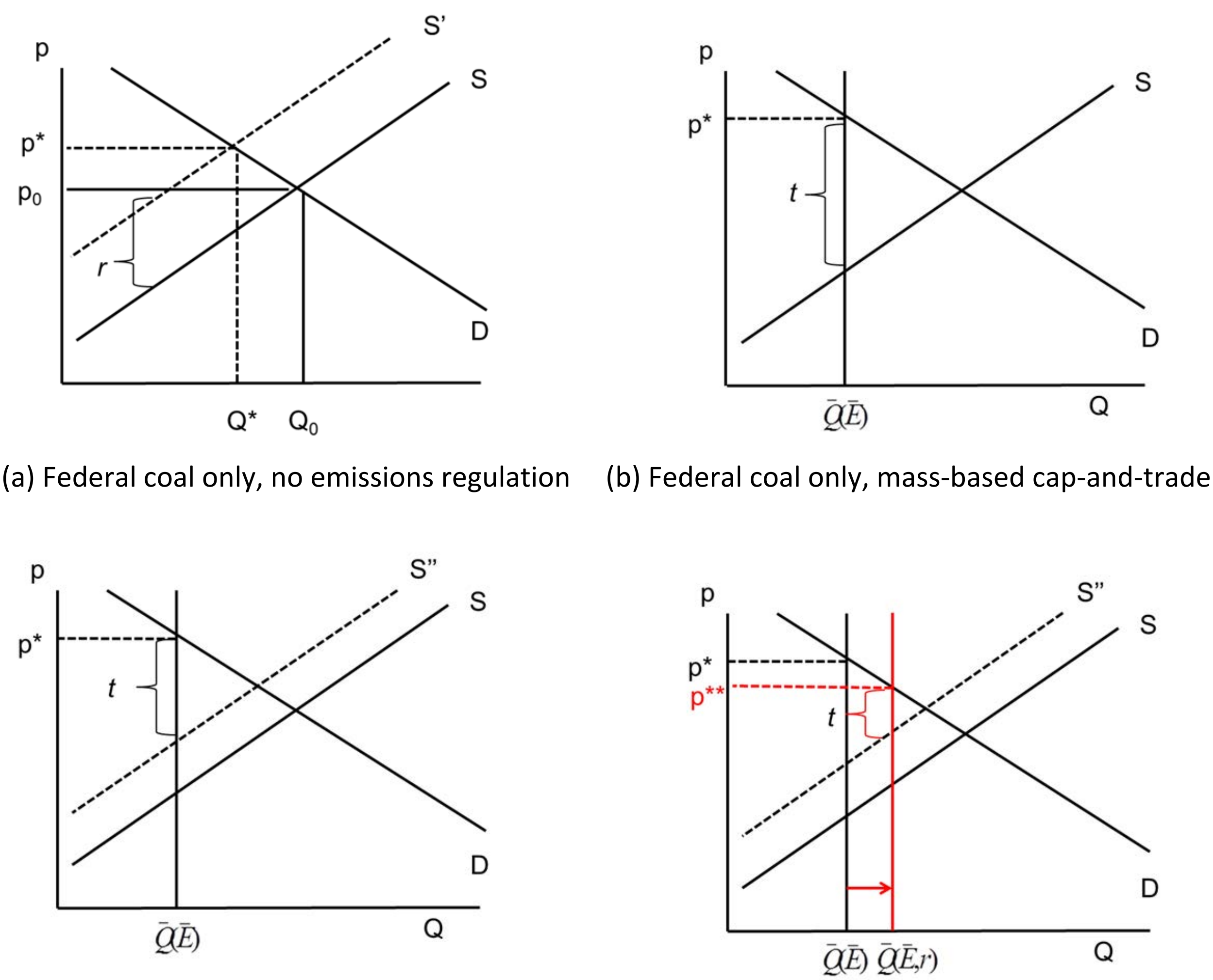
First, suppose there is only one fuel, federal coal, and there is no downstream regulation. Then imposing a carbon adder on federal coal shifts the electricity supply curve up. As a result, the price of electricity rises, the quantity demanded falls, and emissions fall. This standard case is shown in Figure 3a.

Next, suppose that there is only one fuel, federal coal, but there is a binding mass-based emissions limit $\bar{E}$ and a system of tradeable allowances; because there is only one source, the emissions limit implies a binding generation limit $\bar{Q}(\bar{E})$. Without a carbon adder, the allowance price is the usual difference between the demand and supply prices (Figure 3b). When a carbon adder r is introduced (Figure 3c), the supply curve shifts up by r; as long as the cap still binds, however, production, price, and emissions remain the same as without the adder. The price of the tradeable allowance falls one-for-one with carbon adder, so the compliance cost of the cap-and-trade system is partially shifted to the carbon adder.

Next, suppose that there is also generation by non-federal coal. Under a binding mass cap, the comparative statics are the same as in the case of Figure 3c with only federal coal, with

[10] We abstract from the upstream coal market for simplicity but assume throughout that an increase in the per-ton coal royalty will (weakly) increase prices for coal mined under federal leases. In the case of a perfectly competitive upstream coal market with infinitely elastic supply and homogenous generation and transportation costs, r would be equal to the coal adder in \$/MWh. Alternatively, r can be thought of as the carbon adder if it were charged directly to electricity generators (rather than mines).

Figure 3. Electricity demand and supply:
different fuels, with and without downstream regulation



(a) Federal coal only, no emissions regulation

(b) Federal coal only, mass-based cap-and-trade

(c) Federal coal, non-federal coal, and mass-based cap-and-trade

(d) Federal coal, other (gas), and mass-based cap-and-trade

the exception that the electricity supply curve shifts up by less than *r* and consequently the price of the tradeable permit declines less than one-for-one with the carbon adder.[11] Because the relative cost of federal coal has increased, federal coal generation declines and this displaced federal coal is replaced one-for-one by non-federal coal.

[11] Specifically, it follows from (17) and (18) in Section 3.3 that $dt/dr = -C''_{NFC} / \left(C''_{FC} + C''_{NFC}\right)$, where C''_{FC} and C''_{NFC} are the slopes of the marginal cost curves of generation by federal and non-federal coal, respectively.

Now suppose instead there are two fuels, federal coal and other (gas), and a binding mass cap. Again, the carbon adder shifts up the electricity supply curve. Because federal coal becomes relatively more expensive, generation is shifted from federal coal to other. In this case, however, the other fuel has a lower emissions rate than coal, so this shift in the generation mix reduces total emissions for a given quantity of generation. As a result, more generation can occur for a given emissions cap, so the effective cap on generation increases as is shown in Figure 3d. Because the emissions cap is still binding, the increase in generation leads to a fall in the price of electricity. The price of the tradeable permit now falls for the additional reason that the gap between the demand price and the supply price on the shifted supply curve falls. Moreover, the decline in the price of the tradeable permit exceeds the decline in the electricity price.

Next consider rate regulation with two fuels, federal coal and other (gas). Because there are only two fuels, the rate standard dictates the share of each fuel in generation. As a result, an increase in the carbon adder cannot result in fuel shifting (there is no non-federal coal in this example), and has the effect of increasing the marginal cost of coal generation so the marginal cost of electricity increases by the rate-determined share of federal coal in generation. Thus the supply and demand diagram is Figure 3a, except that the shift up in the supply curve is r times the generation share of federal coal. Price increases and consumption falls. Both coal and gas generation decrease in proportion to the decline in total generation, and because the emissions rate is fixed, lower generation results in lower emissions. Under the rate standard, the tradeable permits serve to equate the marginal costs of coal and gas generation; with the introduction of the carbon adder, the gap between these effective marginal costs falls so the price of the tradeable permit falls. However, this change in the permit price is a net-zero transfer between coal and gas generation and does not affect the weighted average marginal cost of electricity; thus it does not have an additional effect on price, generation, or emissions.

Finally, we note that the comparative statics shown in these figures are the same if federal coal generation (i.e., the mining of federal coal) is subject to a quantity limit. In that case, a quantity limit for federal coal that induces a given value r of the shadow price shifts up the electricity supply curve by the same amount as would imposing a carbon adder of that value. Thus a quantity limit on federal coal yields the same equilibrium outcomes when the carbon adder equals the shadow price of federal coal induced by that quantity limit. In particular, in the framework of Figure 3d with federal coal, other (gas), and a binding downstream cap-and-trade policy, a reduction in federal coal production reduces the price of tradeable permits, reduces electricity prices, increases generation by other sources (gas), and reduces emissions as long as the cap-and-trade policy continues to bind.

3.2. No Downstream Regulation

We model production decisions by a representative firm that takes prices and maximizes profits.[12] Generation costs from each source are additively separable, increasing, and convex in production. With no downstream policy in place, the firm maximizes profits:

$$\max_{q_{FC}, q_{NFC}, q_O} \pi = pQ - \sum_i C_i(q_i) - rq_{FC}\ , \tag{1}$$

where $Q = q_{FC} + q_{NFC} + q_O$, where q_{FC}, q_{NFC}, and q_O are respectively the quantities of generation by federal coal, non-federal coal, and other, and the summation in (1) is over these three sources.

The firm's first order conditions for each type of electricity imply that it will produce up to the point where price equals the adder-inclusive marginal cost for each source:

$$\frac{\partial \pi}{\partial q_{FC}} = p - C'_{FC}(q_{FC}) - r = 0 \tag{2}$$

$$\frac{\partial \pi}{\partial q_{NFC}} = p - C'_{NFC}(q_{NFC}) = 0\text{, and} \tag{3}$$

$$\frac{\partial \pi}{\partial q_O} = p - C'_O(q_O) = 0\ , \tag{4}$$

where $C'_{FC} = dC_{FC}(q_{FC}) / dq_{FC}$ and so forth.

Quantity and price effects. Taking the total differential of (2) – (4) and solving the system of equations yields the following comparative statics for a change in r:

[12] This is most similar to the approach taken by Holland et al. (2009) in the context of a low carbon fuel standard. Fischer and Newell (2008) use this in the context of multiple policy instruments and fuels with different carbon intensities. We also took an alternative approach, deriving comparative statics from "reduced-form" inverse demand and supply curves, although we do not present those (duplicative) results here. This alternative approach is common in public finance for studying tax incidence. Horowitz and Linn (2015) employ this alternative approach to study the effects of technological change under rate-based regulation. See the Appendix for details.

$$\frac{dp}{dr} = \frac{C''_{NFC} C''_O p'}{\left(C''_{FC} C''_{NFC} + C''_{FC} C''_O + C''_{NFC} C''_O\right) p' - C''_{FC} C''_{NFC} C''_O} \geq 0 \tag{5}$$

$$\frac{dq_{FC}}{dr} = \left[\frac{C''_{NFC} C''_O - \left(C''_{NFC} + C''_O\right) p'}{C''_{NFC} C''_O p'} \right] \frac{dp}{dr} \leq 0 \tag{6}$$

$$\frac{dq_{NFC}}{dr} = \frac{1}{C''_{NFC}} \frac{dp}{dr} \geq 0 \tag{7}$$

$$\frac{dq_O}{dr} = \frac{1}{C''_O} \frac{dp}{dr} \geq 0 \tag{8}$$

$$\frac{dQ}{dr} = \frac{1}{p'} \frac{dp}{dr} \leq 0 \tag{9}$$

where $C''_{FC} = d^2 C_{FC}(q_{FC}) / dq^2_{FC}$, etc., and $p' = dp / dQ$ is the slope of the inverse demand curve for electricity.

Absent downstream emissions regulation, an increase in the adder increases the effective cost of federal coal and increases the equilibrium price of electricity. The increase in the relative cost of federal coal shifts generation from federal coal to non-federal coal and other sources. The amount of substitution of non-federal coal and other for federal coal is determined by the slopes of the supply curve for the various fuels (that is, by $1/C''_{FC}$, $1/C''_{NFC}$, and $1/C''_O$). For example, if the supply of non-federal coal is perfectly elastic, non-federal coal expands by the amount that federal coal contracts and electricity prices do not change. In general, however, increasing marginal costs imply that the price of electricity rises and total generation falls.

Emissions effects. We normalize the units of emissions to be the mass of CO_2 emitted from generating 1 MWh from coal, so that 1 MWh of coal generation produces 1 unit of CO_2 emissions. Emissions from "other" are a fraction λ of the emissions from coal, where $0 \leq \lambda \leq 1$. With these units, total power sector emissions are,

$$E = q_{FC} + q_{NFC} + \lambda q_O \,. \tag{10}$$

Differentiating (10) with respect to r gives the impact of a carbon adder on emissions:

$$\frac{dE}{dr} = \frac{dq_{FC}}{dr} + \frac{dq_{NFC}}{dr} + \lambda \frac{dq_O}{dr} = \frac{dQ}{dr} - (1-\lambda)\frac{dq_O}{dr} \leq 0, \tag{11}$$

where the second equality obtains by substitution and where the inequality follows from (8), (9), and the maintained assumption that coal is more emissions-intensive than other sources.

Equation (11) illustrates the two channels by which the carbon adder reduces emissions absent downstream regulation: a reduction in demand because of the higher electricity price, and fuel substitution from federal coal to the cleaner other source because of the increase in the effective relative price of coal induced by the adder.

Welfare impacts. Welfare from the perspective of the social planner includes damages from electricity sector emissions:

$$W = U(Q) - \sum_i C_i(q_i) - \theta E, \tag{12}$$

where θ is the marginal damages of a unit of emissions. We treat the carbon adder as a transfer between producers and the government that does not affect total welfare.

The first-order welfare effect of changing the carbon adder is the sum of the effect of the producer's output response to the adder on royalties paid and the change in external damages:[13]

$$\frac{dW}{dr} = r\frac{dq_{FC}}{dr} - \theta\frac{dE}{dr}. \tag{13}$$

For the introduction of a carbon adder ($r = 0$), the first-order welfare effect is driven entirely by the change in external damages. In this case, the reduction of emissions characterized by equation (11) implies the carbon adder is welfare-improving if the marginal damages are positive ($\theta > 0$). This first-order approximation is valid when marginal damages are not

[13] Equation (13) follows by differentiating W with respect to *r* and using the consumer and producer first order conditions or, equivalently, from the envelope theorem.

internalized because the damages dominate second-order effects (i.e., the traditional deadweight loss triangle) for small changes in *r*.

If (13) is interpreted as a first-order Taylor series approximation around $r = 0$, then setting (13) to zero yields a first-order approximation to the welfare-maximizing value of a newly introduced carbon adder:

$$r^* = \theta\left(\frac{dE/dr}{dq_{FC}/dr}\right). \tag{14}$$

This local approximation has an intuitive interpretation: the optimal value of *r* is the externality value of the emissions reduction it induces per MWh of reduced coal generation. The factor in brackets in (14) adjusts the externality value of coal generation emissions (θ) for the leakage associated with the carbon adder. At one extreme, if the carbon adder reduces consumption of federal coal and there is no substitution, this factor equals 1 and $r^* = \theta$. At the other extreme, if there is perfect substitution of non-federal for federal coal, then $dE/dr = 0$ and $r^* = 0$. An intermediate case is perfect substitution of other (gas) for federal coal with no change in generation by non-federal coal. Then $dE/dr = (1-\lambda)dq_{FC}/dr$ and $r^* = \theta(1–\lambda)$, that is, the optimal value of *r* is the externality value of the emissions reduction associated with switching from federal coal to other.

3.3. Mass-based Cap with Uncovered Sources

We next consider the effect of a carbon adder in the presence of a cap-and-trade downstream emissions regulation. In practice, the mass cap might not cover all sources in the power sector; for example, the mass-based compliance option in the CPP does not cover gas combustion turbines with less than 25 MW capacity (peakers).[14] We therefore introduce a fourth generation source, *U*, for uncovered sources. The emissions rate from source *U* is a fraction λ_U of the coal emissions rate.

[14] This is also true of many existing cap-and-trade policies. For example, the Regional Greenhouse Gas Initiative (RGGI) only covers electricity generators with a capacity of 25 MW or more.

Because U is uncovered, its emissions do not count towards the mass cap. Thus the mass cap constraint is,

$$q_{FC} + q_{NFC} + \lambda q_O \le \bar{E} \,. \tag{15}$$

The representative firm maximizes profits subject to the constraint (15). This yields the constrained maximization problem,

$$\max_{q_{FC}, q_{NFC}, q_O, q_U, t} pQ - \sum_i C_i(q_i) - rq_{FC} - t\left(q_{FC} + q_{NFC} + \lambda q_O - \bar{E}\right), \tag{16}$$

where the summation extends over all four sources. We consider the case that the mass cap is binding, so the price of the tradeable allowance is t. Because the source U is not covered, the firm does not need to purchase allowances for q_U.

Quantity and price effects. The firm's five first order conditions determine equilibrium quantities and allowance prices given r when the cap is binding. It is shown in the appendix that differentiating that system of equations with respect to r yields the following comparative statics results:

$$\frac{dp}{dr} = \frac{\lambda(1-\lambda)C''_{NFC}C''_U p'}{\Delta} \le 0 \tag{17}$$

$$\frac{dt}{dr} = \left[\frac{(1-\lambda)C''_U p' - C''_O\left(C''_U - p'\right)}{\lambda(1-\lambda)C''_U p'}\right]\frac{dp}{dr} \le 0 \tag{18}$$

$$\frac{dq_{FC}}{dr} = \left[\frac{(1-\lambda)^2 C''_U p' - \left(C''_O + \lambda^2 C''_{NFC}\right)\left(C''_U - p'\right)}{\lambda(1-\lambda)C''_{NFC}C''_U p'}\right]\frac{dp}{dr} \le 0 \tag{19}$$

$$\frac{dq_{NFC}}{dr} = \left[\frac{C''_O\left(C''_U - p'\right) - (1-\lambda)^2 C''_U p'}{\lambda(1-\lambda)C''_{NFC}C''_U p'}\right]\frac{dp}{dr} \ge 0 \tag{20}$$

$$\frac{dq_O}{dr} = \left[\frac{C''_U - p'}{(1-\lambda)C''_U p'}\right]\frac{dp}{dr} \ge 0 \tag{21}$$

$$\frac{dq_U}{dr} = \frac{1}{C''_U}\frac{dp}{dr} \le 0 \tag{22}$$

$$\frac{dQ}{dr} = \frac{1}{p'}\frac{dp}{dr} \geq 0 \tag{23}$$

where $\Delta = \left(C''_{FC}C''_{O} + C''_{NFC}C''_{O} + \lambda^2 C''_{FC}C''_{NFC}\right)\left(C''_{U} - p'\right) - \left(1-\lambda\right)^2\left(C''_{FC} + C''_{NFC}\right)C''_{U}\,p' \geq 0$.

The price and quantity effects generalize those in Figure 3d to multiple fuels and uncovered sources. The increase in the relative price of coal shifts generation to nonfederal coal and other, so the total generation from covered sources increases because the emissions constraint is binding and generation is from a cleaner mix. Thus the prices of electricity and tradeable allowances fall. With a lower allowance price, both non-federal coal generation and other generation increase even though the price of electricity declines. The lower electricity price provides less reward for uncovered generation (which gets no benefit from the decline in the tradeable permit price), so uncovered generation falls. On net, total generation increases.

Emissions effects. Total emissions include all sources:

$$E = q_{FC} + q_{NFC} + \lambda q_O + \lambda_U q_U\,. \tag{24}$$

Although emissions from covered sources are subject to a binding cap and thus do not change with *r*, emissions from uncovered sources change as *r* changes:

$$\frac{dE}{dr} = \frac{dq_{FC}}{dr} + \frac{dq_{NFC}}{dr} + \lambda\frac{dq_O}{dr} + \lambda_U\frac{dq_U}{dr} = \lambda_U\frac{dq_U}{dr} \leq 0\,, \tag{25}$$

where the second equality in (25) follows from the fact that the cap fixes total emissions from covered sources. The change in emissions from all sources depends only on the response of uncovered sources. The decline in the price of electricity reduces uncovered generation, so emissions decline. In effect, increasing the carbon adder reduces leakage under a partial mass cap.

Welfare impacts. The welfare function is still given by (12), where the summation extends over all four sources and emissions are given by (24). The effect on welfare of a change in r is still given by (13).[15] Although the mass cap fixes total emissions from covered sources, there is now the possibility of emissions-related welfare gains because the carbon adder reduces leakage. Because the emissions from uncovered sources decline in response to an increase in the carbon adder, the introduction of a carbon adder produces first-order welfare gains.

The local approximation to the optimal value of a newly introduced carbon adder is given by substituting (25) into (14):

$$r^* = \theta\lambda_U \frac{dq_U / dr}{dq_{FC} / dr}, \tag{26}$$

where the derivatives are evaluated at $r = 0$. Under the mass cap with uncovered sources, the optimal value of r is the externality value from generating one MWh from the uncovered source ($\theta\lambda_U$), scaled by the reduction in uncovered generation per unit reduction of federal coal generation.

3.4. Rate Regulation with Uncovered Sources

We now turn to rate-based regulation with uncovered sources.[16] The rate-based standard regulates the emissions rate or, equivalently, sets an emissions limit that is proportional to total generation by covered sources. Let R denote the rate standard, which we assume is set between the emission rates for coal and other so that $\lambda \leq R < 1$. The rate-based standard, which only includes covered sources, is thus $q_{FC} + q_{NFC} + \lambda q_O \leq R(q_{FC} + q_{NFC} + q_O)$. Rearranging this rate limit gives $(1-R)q_{FC} + (1-R)q_{NFC} + (\lambda-R)q_O \leq 0$ or,

$$q_{FC} + q_{NFC} + \tilde{\lambda} q_O \leq 0, \tag{27}$$

[15] Differentiation of the welfare function (12) including the uncovered source yields $\frac{dW}{dr} = r\frac{dq_{FC}}{dr} + (t-\theta)\left[\frac{dq_{FC}}{dr} + \frac{dq_{NFC}}{dr} + \lambda\frac{dq_O}{dr}\right] - \theta\lambda_U\frac{dq_U}{dr}$. The binding mass cap (15) implies that the term in brackets is zero, and substitution of (25) into the final term in this expression yields (13).

[16] One compliance option under the CPP is rate-based regulation with tradable allowances. Under the CPP, the rate-based regulation would cover existing sources but not new fossil fuel sources, which are regulated separately under Section 111(b) of the Clean Air Act.

where $\tilde{\lambda}$ = (λ-R)/(1-R). Note that $\tilde{\lambda} \leq 0$. Thus in the case here of two emission rates, coal and other, the rate standard mandates a fractional mix between generation by coal and by other.

The representative firm maximizes profits subject to (27):

$$\max_{q_{FC}, q_{NFC}, q_O, q_U, t} pQ - \sum_i C_i(q_i) - rq_{FC} - t\left(q_{FC} + q_{NFC} + \tilde{\lambda} q_O\right), \tag{28}$$

where the summation extends over all four fuels.

Mathematically, the only differences between the rate problem (28) and the mass problem (16) are that λ in (16) is replaced by $\tilde{\lambda}$ and that $\bar{E}$ in (16) takes on the value of zero. Because $\bar{E}$ does not enter the comparative statics expressions, the comparative statics results for the mass case with leakage apply directly to the rate case with leakage, with λ replaced by $\tilde{\lambda}$. Because λ and $\tilde{\lambda}$ have different signs, the signs of several of the comparative statics expressions change, so we summarize them here.

Quantity and price effects. Substitution of $\tilde{\lambda}$ for λ in (17) – (23) yields,

$$\frac{dp}{dr} = \frac{\tilde{\lambda}\left(1-\tilde{\lambda}\right)C''_{NFC}C''_U p'}{\tilde{\Delta}} \geq 0 \tag{29}$$

$$\frac{dt}{dr} = \left[\frac{\left(1-\tilde{\lambda}\right)C''_U p' - C''_O\left(C''_U - p'\right)}{\tilde{\lambda}(1-\tilde{\lambda})C''_U p'}\right]\frac{dp}{dr} \leq 0 \tag{30}$$

$$\frac{dq_{FC}}{dr} = \left[\frac{\left(1-\tilde{\lambda}\right)^2 C''_U p' - \left(C''_O + \tilde{\lambda}^2 C''_{NFC}\right)\left(C''_U - p'\right)}{\tilde{\lambda}(1-\tilde{\lambda})C''_{NFC}C''_U p'}\right]\frac{dp}{dr} \leq 0 \tag{31}$$

$$\frac{dq_{NFC}}{dr} = \left[\frac{C''_O\left(C''_U - p'\right) - \left(1-\tilde{\lambda}\right)^2 C''_U p'}{\tilde{\lambda}(1-\tilde{\lambda})C''_{NFC}C''_U p'}\right]\frac{dp}{dr} \geq 0 \tag{32}$$

$$\frac{dq_O}{dr} = \left[\frac{C''_U - p'}{(1-\tilde{\lambda})C''_U p'}\right]\frac{dp}{dr} \leq 0 \tag{33}$$

$$\frac{dq_U}{dr} = \frac{1}{C''_U}\frac{dp}{dr} \geq 0 \tag{34}$$

$$\frac{dQ}{dr} = \frac{1}{p'}\frac{dp}{dr} \leq 0 \tag{35}$$

where $\tilde{\Delta} = \left(C''_{FC}C''_{O} + C''_{NFC}C''_{O} + \tilde{\lambda}^2 C''_{FC}C''_{NFC}\right)\left(C''_{U} - p'\right) - \left(1-\tilde{\lambda}\right)^2\left(C''_{FC} + C''_{NFC}\right)C''_{U}p' \geq 0$.

The comparative statics follow the results in the two-fuel supply and demand discussion in Section 3.1. As in the mass-based case, an increase in the carbon adder makes federal coal more expensive, inducing a shift to non-federal coal. The rate standard fixes the ratio of coal to gas. The carbon adder increases the marginal cost of all coal and thus of electricity, so the price of electricity increases and production falls. The higher electricity price induces more uncovered generation. Because the marginal cost of coal increases, the price of the tradeable permit falls.

Emissions effects. Emissions are given by (24), which can be rewritten as $E = \left(1 - R\right)\left(q_{FC} + q_{NFC} + \tilde{\lambda} q_U\right) + RQ + \left(\lambda_U - R\right)q_U$. The first term in this expression is zero under the binding rate constraint (27). Thus the effect on emissions of a change in *r* is,

$$\frac{dE}{dr} = R\frac{dQ}{dr} + \left(\lambda_U - R\right)\frac{dq_U}{dr}. \tag{36}$$

The two terms in (36) represent the two channels whereby the carbon adder affects emissions under rate regulation with leakage. The first is the total demand effect, which is negative because $dQ/dr \leq 0$ by (35). The second is the effect on generation by uncovered sources. Because uncovered generation increases with *r*, this term leads to emissions reductions if the emissions rate of uncovered sources is less than the rate standard and vice versa.

Welfare impacts. The welfare function is the same in the rate and mass case so welfare comparative statics continue to be given by (13). Local to $r = 0$, the sign of the first-order welfare effect depends on the sign of emissions. The optimal value of *r* under the local approximation continues to be given by (14). In the plausible case under the CPP that the marginal uncovered sources (in particular new natural gas combined cycle) are cleaner than or the same as covered sources (on average), the optimal carbon adder would be positive.

3.5. Restrictions on the Quantity of Federal Coal Production

Sections 3.2 – 3.4 consider the effect of a carbon adder that increases royalties on federal coal. An alternative policy is to impose a quantity cap on the amount of coal that could be mined from federal lands through quantity restrictions on new federal coal leases. Modifying the analysis above for such a policy entails dropping the terms involving the royalty rate and adding the quantity constraint $q_{FC} \le \overline{q}_{FC}$. In the simple setup here, price regulation and quantity regulation yield the same comparative statics. That is, $dp / d\overline{q}_{FC} = (dp / dr) / (dq_{FC} / dr)$, where $dp / d\overline{q}_{FC}$ is the price comparative statics under the quantity restriction case and the derivatives with respect to r are those derived above, and so forth for Q, t, and the individual fuel quantities.

4. Integrated Planning Model: Research Design

We used ICF International's Integrated Planning Model (IPM) to obtain quantitative estimates of the effects of implementation of various possible reforms to the federal coal program. IPM is a multi-region dynamic perfect-foresight optimization model of the electric power sector, which for this study was solved through the year 2050 in decadal time slices. IPM endogenously determines electricity generation capacity expansion, unit dispatch, fuel switching, and compliance decisions, and also endogenously solves for power and fuel prices. IPM was used by the EPA in its Regulatory Impact Analysis (RIA) of the Clean Power Plan. It is a high-fidelity model containing parameters for 36 coal supply regions, 14 coal grades, and the coal transportation and distribution network. The IPM coal supply curves are generated from mine-level data. For the purposes of this study, the coal supply module of IPM was extended to incorporate mine-level information on the mix of federal and non-federal coal.[17]

This study uses a set of base cases that differ in their economic assumptions and assumptions about implementation of the CPP. These base cases are then used to assess potential reforms to the federal coal program. The effect of the potential reforms is estimated as the differences between the policy case and the relevant base case and measured as changes in power

[17] Additional information on IPM is available in the EPA CPP RIA (EPA 2015, Chapter 3) and at https://www.epa.gov/airmarkets/analysis-clean-power-plan.

sector CO_2 emissions, coal production (federal and non-federal), fuel substitution, and additional energy market indicators described below.

4.1. Base Cases

The base cases reflect two sets of underlying economic assumptions and three permutations of CPP implementation.

Economic assumptions. The primary base case approximates the economic assumptions (including costs of different types of electricity generation, energy efficiency, and aggregate demand) in the EPA's final Regulatory Impact Assessment of the Clean Power Plan (EPA, 2015). The secondary base case has the same assumptions concerning total demand and energy efficiency, but has different fuel cost assumptions than the primary base case, mainly lower costs of coal and higher costs of renewables. The secondary base case provides a check of the sensitivity of the policy effects to changes in input fuel cost assumptions. The policy and legal assumptions for both the primary and secondary base cases are those of October 2015 upon the publication of the CPP final rule.[18]

Assumptions about CPP implementation. As of this writing, the form of state implementation of the CPP is undecided. In addition, the CPP is facing court challenges that could substantially reduce its stringency. The study therefore examines the effect of coal royalty reform under three CPP cases:

1. "CPP-mass" assumes that all states use mass-based standards with regional emissions allowance trading to comply with the CPP. The CPP-mass scenario covers most existing and new fossil fuel sources, with the exception of simple-cycle natural gas combustion turbines (peakers) and some other units.[19] The mass-based scenario is modeled on compliance option 1 in the CPP final rule, in which the mass cap is extended by state legislation or regulation to cover both existing and new sources.[20]

[18] The primary base case uses the publicly available assumptions of EPA Base Case v.5.15, which was used in the final CPP RIA. The secondary base case uses load growth, build case, and natural gas production assumptions from EPA Base Case v.5.15, with other cost assumptions taken from EPA Base Case v.5.13, which was used in the June 2014 draft CPP RIA, however the coal supply curves for the alternative base case were based on ICF internal base assumptions and have lower costs than EPA's v.5.15.

[19] Also excluded are units with capacity less than 25 MW, modified units, and some other units (see 80 FR 64716).

[20] Because new sources are regulated under §111(b) of the Clean Air Act and existing sources are regulated under §111(d), EPA cannot compel states to create a mass cap that covers both existing and new sources. Compliance

2. "CPP-rate" assumes that states use rate-based standards with regional trading as the compliance mechanism.[21] Rate-based regulation excludes all new and modified fossil sources, although those new sources must meet the new and modified source standards under §111(b).
3. "No CPP" models a future without the CPP.

4.2. Policy Scenarios

The policy scenarios consider increases in the federal coal royalty in the form of carbon adders, assessed at the mine in dollars per short ton of coal. The results presented here calibrate the carbon adders to 20%, 50%, and 100% of the US Government Social Cost of Carbon (SCC).[22] The effect of each of these policy scenarios was assessed separately against the primary and secondary base cases. In addition, a smaller adder of $2.50 was studied under the secondary base case. These adders represent an additional charge per short ton of coal, assessed on top of the existing federal royalty rate of 12.5%. They are additive, unlike the *ad valorem* royalty rate.

Federal coal lease contracts cover an initial period of 20 years, and are thereafter subject to renewal every 10 years. Existing leases would not be subject to royalty rate changes. Thus a carbon adder could only be applied to new, renewed, or modified leases. Based on a preliminary analysis of the issuance date of existing leases, we model the phasing-in of the carbon adder as a linearly increasing royalty schedule for all leases, ramping up over a 10-year period from 2016 to 2026.[23]

For mines that include both federal and non-federal coal, the adder was assessed to the mine output at each step of the mine's supply curve in proportion to the fraction of federal coal in the mine. This proportional computation of royalties is consistent with current practice within

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option 1 in the final rule envisions that states adopt additional legislation or regulation that allows them to place both existing and new sources under the same mass cap and, if that is done, expands the mass cap to include new sources. The caps used in the simulations are those that include these "new source complements" in Table 14 (80 FR 64888). The six trading regions modeled align with interconnects and are West (WECC), North Central (MISOO), South Central (SPP + ERCOT), Southeast (SERC + FL), East Central (PJM), and Northeast (NPCC). Consistent with standard IPM solution methods, EGU-level intertemporal optimal dispatching, new builds, exports, etc. are computed subject to the state-level limits and regional trading.

[21] The state rate-based standards are the emissions performance goals in the final rule, Table 12 (80 FR 64824).

[22] The SCC is the monetized present value of damages from emission of an additional metric ton of CO_2. The US government estimate of the SCC used here is the November 2013 update (U.S. OMB 2013).

[23] It was infeasible to modify the IPM coal module to incorporate mine-level leasing contract information.

a logical mining unit. The typical checkerboard pattern of non-federal inholdings in Western coal tracts is assumed, consistent with expert opinion, to make it economically infeasible to mine the non-federal inholdings separately. State and private royalty rates are modeled as remaining unchanged if federal royalties are increased to incorporate a carbon adder. The adjusted mine-level engineering supply curves were aggregated in the IPM coal supply module to regional supply curves by coal rank, that now incorporate the federal carbon adder. Because the SCC schedule varies over time and the adder is ramped in over 10 years, the supply curves are actually a sequence of supply curves over time that incorporate the time-varying federal adder.

The values of the SCC and the first ten years of the carbon adder, indexed to the SCC and computed for typical Powder River Basin sub-bituminous coal, are given in Table 2. To fix magnitudes, the average price of PRB coal was approximately $11/short ton in 2015.

Table 2. Simulated Carbon Adders for Federal Coal Indexed to SCC with 10-year linear phase-in (2015$)

	20% SCC	50% SCC	100% SCC
2016	$1.53	$3.83	$7.67
2018	$4.84	$12.10	$24.21
2020	$8.67	$21.69	$43.37
2022	$12.43	$31.07	$62.13
2024	$16.70	$41.76	$83.52
2026	$19.37	$48.41	$96.83
2028	$20.17	$50.43	$100.86
2030	$20.98	$52.45	$104.90

Notes: Computed for typical PRB sub-bituminous coal (heat content 8800 Btu/lb) using national average CO_2/Mmbtu of 214.3 (source: http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11). The SCC is the 2013 USG estimate (OMB 2013).

Following EPA's CPP RIA, electricity demand is exogenous and fixed across all policy cases to match the base case. Implied by this assumption is that the policy cases induce no additional energy efficiency gains.

5. IPM Results

This section summarizes the IPM results on total emissions, generation mix, coal production by basin, tradable permit prices, and wholesale electricity prices. Results are presented for the no-CPP, mass-based CPP, and rate-based CPP simultaneously to facilitate comparison of the effects of the upstream policy under different downstream scenarios. We initially focus on results for the primary base case, then briefly summarize the insensitivity of these results to using the secondary base case. We also provide estimates of the change in royalties under the secondary base case. We focus on results for 2030 because the CPP and modeled carbon adder would be fully phased-in by that year.

CO_2 emissions in 2030 are shown in Figure 4 as a function of the carbon adder for the three CPP implementation cases. In this and subsequent figures and tables, the monetary value of the carbon adder is expressed as the adder for a new lease in 2016 dollars per short ton.[24]

Figures 5-8 have the same format as Figure 3 and respectively summarize results for coal production (PRB and national), generation mix, tradable permit prices, and wholesale electricity. Although Figures 4-8 focus on results for 2030, IPM produces results over time, and Figure 9 plots cumulative emissions reductions for three non-interacted policies, relative to the business-as-usual baseline: the mass-based CPP/no carbon adder, the rate-based CPP/no carbon adder, and no CPP/100% SCC carbon adder. Table 3 summarizes the reductions in emissions (first block) and the change in PRB coal production (second block) due to the carbon adder charge for each of the three CPP cases, relative to the same CPP assumption with no adder.

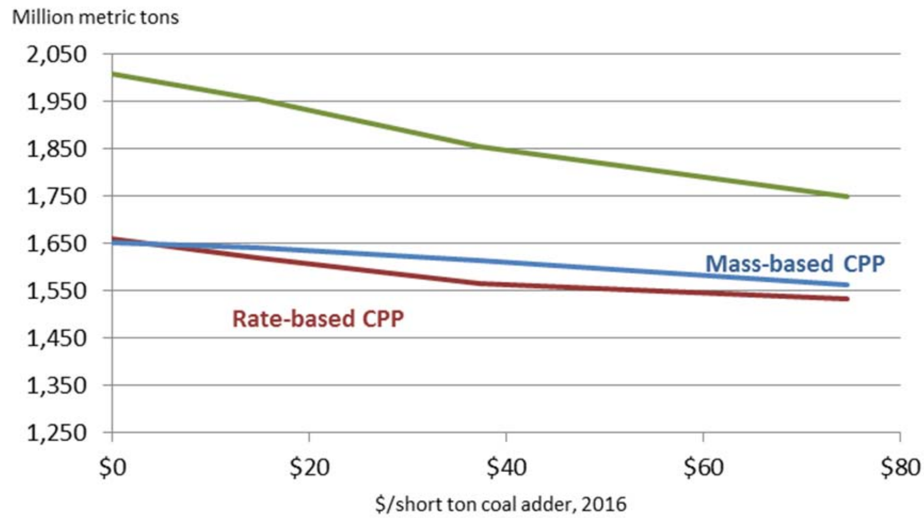
Several broad results stand out from the results in Figures 4-9 and Table 3.

First, in the no-CPP scenario, the emissions reductions are large. For example the 100% SCC adder on federal coal results in a 260 million metric ton (MMT) emissions reduction in 2030 relative to the no-CPP, no-adder case. As can be seen in Figure 4, this decline in emissions is 73% of the estimated 358 MMT reduction under the mass-based CPP (no adder), relative to the no-CPP, no-adder base case.

Second, as can be seen in Figure 5, there is only partial substitution of non-federal for federal coal in the no-CPP case. A large carbon adder essentially makes PRB coal production

[24] As discussed in Section 4, turnover of new leases subject to the adder is modeled as ramping in linearly over 10 years and increasing according to the SCC schedule.

Figure 4
National CO2 Emissions from the Power Sector in 2030
Effect of federal coal royalty increase under various Clean Power Plan implementations

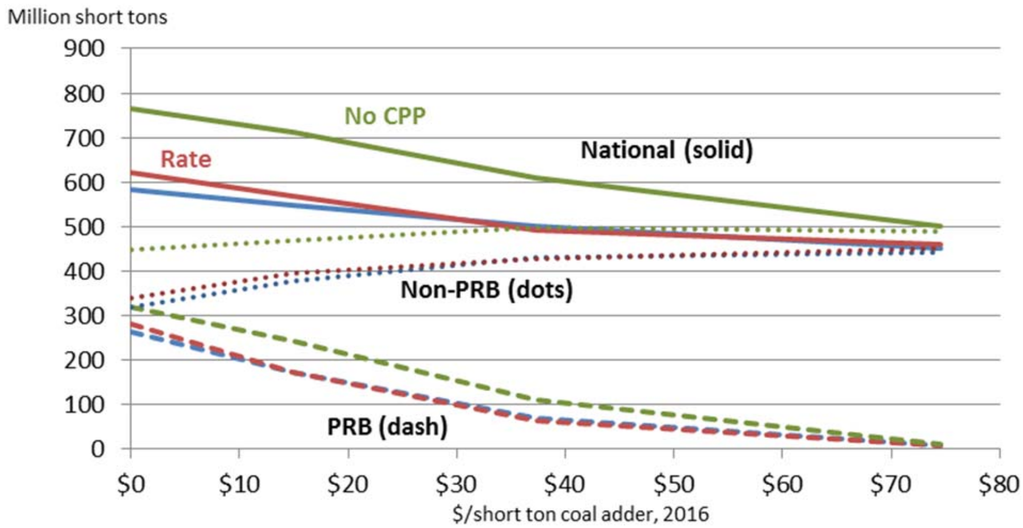


Notes: The lines present power sector emissions in 2030 under the 20%, 50%, and 100% SCC carbon adder case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016. Based on IPM simulations by ICF.

uneconomic, driving it from 318 million short tons in 2030 under the no-CPP, no-adder case to 11 million short tons in the no-CPP, 100% SCC adder case, a decline of 307 million short tons. This decline in PRB production is partially offset by a 42 million short ton increase in non-PRB coal production, or an offset of 14%. The reason for this relatively small offset is that the price of non-federal coal rises enough to make non-coal sources relatively attractive, so that (as seen in Figure 6) the main substitution is from federal coal to natural gas and, to a lesser extent, renewables.

Third, in the no-CPP case, a carbon adder increases fuel prices and consequently increases wholesale electricity prices (Figure 8); comparing the no-adder/no-CPP case to the 100% SCC/no-CPP case, wholesale electricity prices rise by 7%. It is worth keeping in mind that this increase in fuel prices is in part a result of demand being exogenous; extending IPM to allow for some elasticity of demand would mitigate the price impact by reducing electricity consumption. These results for the no-CPP case – a decline in emissions and in federal coal production, partial substitution of non-federal for federal coal, and increased non-coal generation

Figure 5
National, Powder River Basin, and Non-PRB Coal Production in 2030
Effect of federal coal royalty increase under various Clean Power Plan implementations



Notes: The lines present coal production in 2030 under the 20%, 50%, and 100% SCC carbon adder case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016. Based on IPM simulations by ICF .

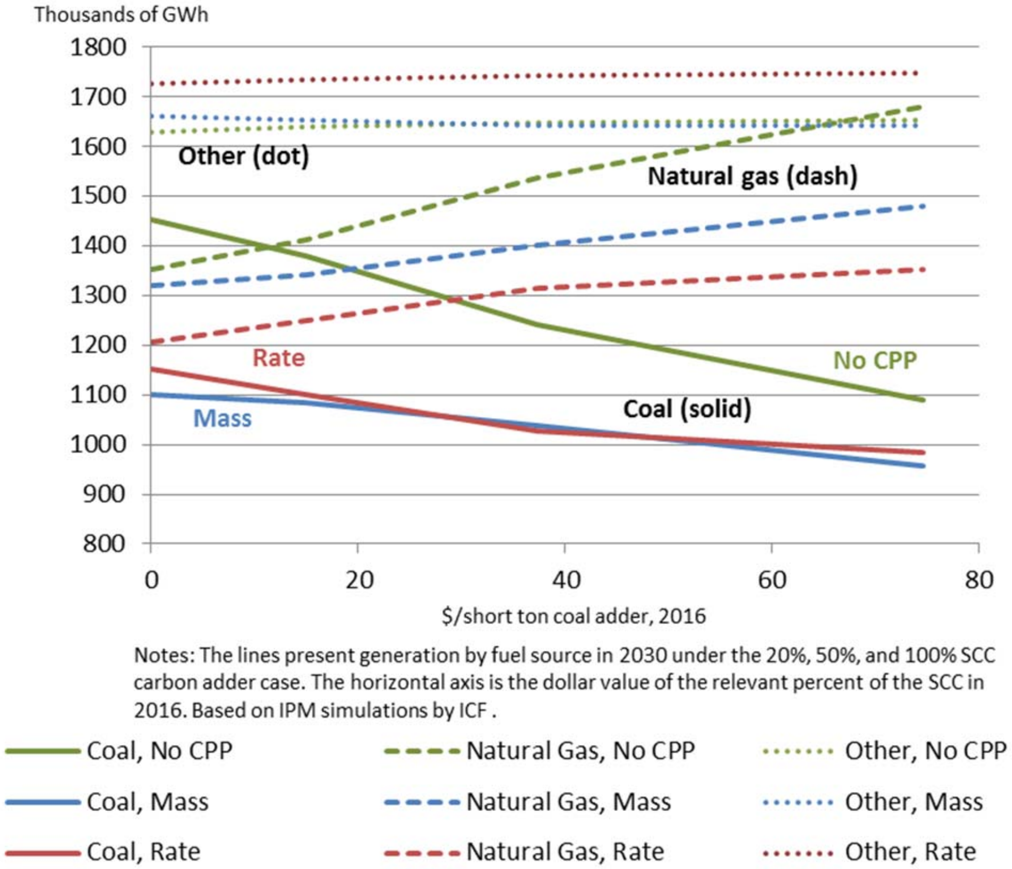
– are all consistent with qualitative results from the no-regulation case using the simple static model in Section 3.2.

Fourth, emissions also fall when a carbon adder is introduced under the mass-based CPP implementation, however the decline is much smaller than without downstream regulation. This is because the carbon adder leads to a decline in the electricity price (Figure 8), which leads uncovered sources to produce and emit less. Put another way, the carbon adder lowers the tradable permit price (Figure 7), making the covered natural gas sources of existing and new natural gas combined cycle (NGCC) generators relatively more attractive than uncovered sources (existing and new simple-cycle natural gas generators) at a given electricity price. Thus new builds and generation are shifted from uncovered sources to covered sources and are brought under the mass cap, leading total emissions to fall. In addition, in the mass-based CPP case, PRB coal production declines sharply with a carbon adder, but there is more substitution from federal to non-federal coal than in the no-CPP case (47% substitution in the 100% SCC case with mass-based CPP, as opposed to 17% substitution without the CPP).

Figure 6

Generation Mix in 2030: coal (solid), natural gas (dash), other (dot)

Effect of federal coal royalty increase under various Clean Power Plan implementations

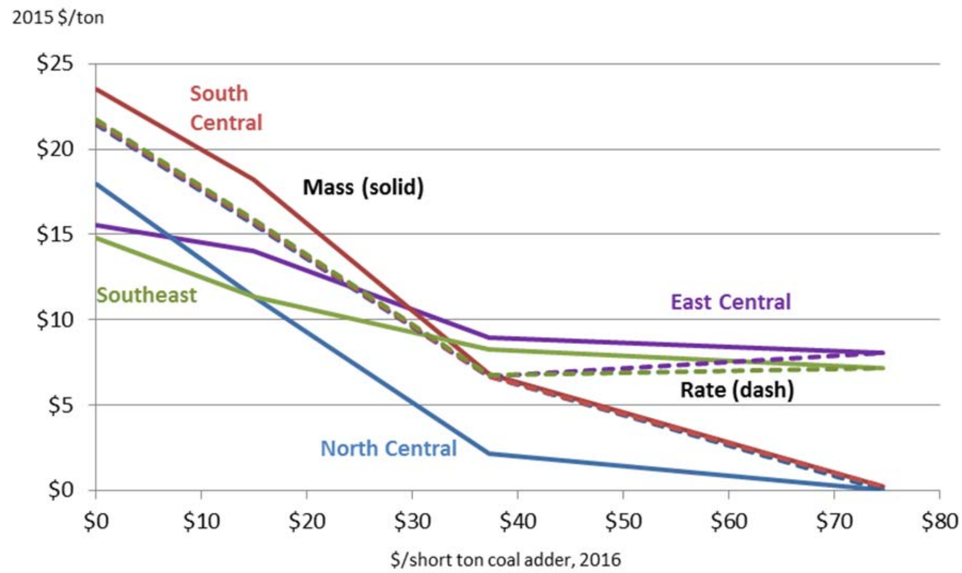


Notes: The lines present generation by fuel source in 2030 under the 20%, 50%, and 100% SCC carbon adder case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016. Based on IPM simulations by ICF .

Fifth, in the mass-based CPP case, including a carbon adder results in a decline in tradable allowance prices (Figure 7) and wholesale power prices (Figure 8). This finding in IPM accords with the static model of Section 3.3 (mass cap with leakage). The amount of the decline in the permit price varies regionally under the regional trading regime, depending on the amount of coal used in the region and the mix of federal and non-federal coal. In this sense, the presence of a carbon adder reduces the CPP compliance cost.

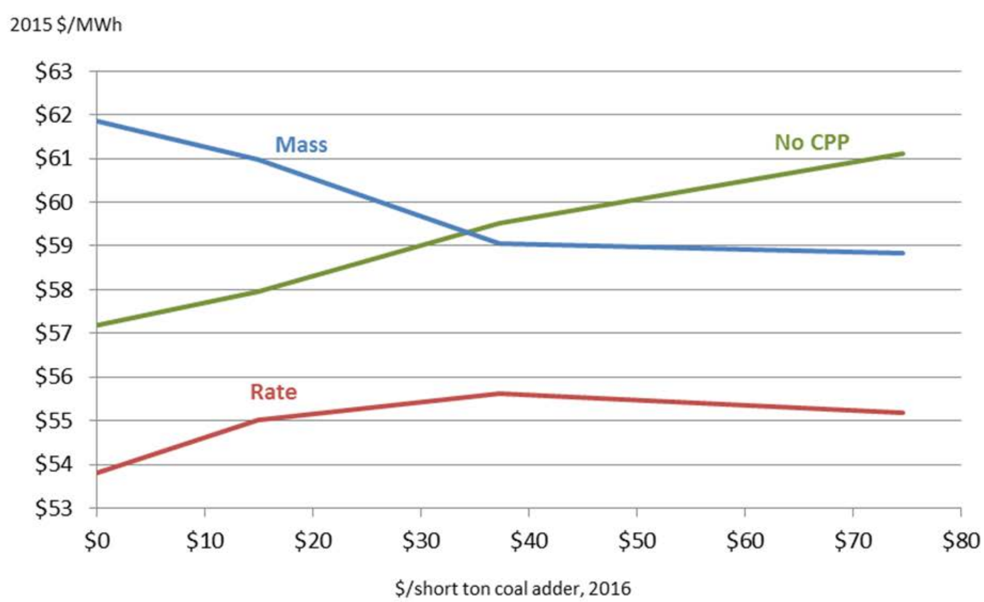
Sixth, in the rate-based CPP case, the carbon adder leads to electricity price increases, a decline in the tradeable permit price, and a reductions in emissions. All three results are consistent with the static model in Section 3.4. The static model predicts emissions reductions if

Figure 7
Tradeable Allowance Prices
Effect of federal coal royalty increase under various Clean Power Plan implementations



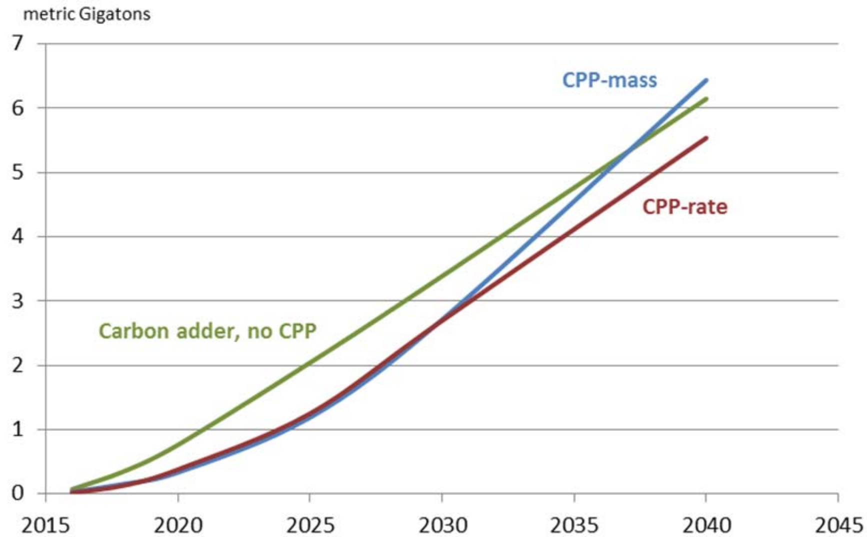
Notes: The lines present the prices of tradeable allowances in 2030 under the 20%, 50%, and 100% SCC carbon adder case by trading region. Prices for the Northeast in 2030 are zero in all cases, and in the West are less than $5, and are not shown. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016. Based on IPM simulations by ICF .

Figure 8
Wholesale electricity prices (national average)
Effect of federal coal royalty increase under various Clean Power Plan implementations



Notes: The lines present generation by fuel source in 2030 under the 20%, 50%, and 100% SCC carbon adder case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016. Based on IPM simulations by ICF .

Figure 9
Cumulative emissions reductions: CPP-mass, CPP-rate, and 100% SCC carbon adder
All emissions are relative to the no-CPP business-as-usual base case; carbon adder asssumes no CPP



Notes: The lines present cumulative power sector emissions by year, starting in 2016, relative to the BAU baseline. The policy scenarios represented by the three lines are the CPP-mass based plan with no carbon adder, the CPP rate-based plan with no carbon adder, and no CPP with a 100% SCC carbon adder on federal coal. Based on IPM simulations by ICF.

Table 3
Estimated Reductions in 2030 Power Sector CO2 Emissions from Federal Coal Royalty Increases

Royalty Adder	Change in CO2 emissions		Change in PRB Coal Production	
percent of SCC	million metric tons	percent	million short tons	percent
		Changes in 2030, relative to no CPP base case		
20% SCC	-54	-2.7%	-76	-24.0%
50% SCC	-155	-7.7%	-208	-65.4%
100% SCC	-260	-13.0%	-308	-96.7%
		Changes in 2030, relative to CPP/rate-based case		
20% SCC	-39	-2.4%	-107	-38.3%
50% SCC	-95	-5.7%	-218	-77.7%
100% SCC	-126	-7.6%	-272	-96.8%
		Changes in 2030, relative to CPP/mass-based case		
20% SCC	-10	-0.6%	-92	-35.0%
50% SCC	-37	-2.3%	-193	-73.1%
100% SCC	-90	-5.5%	-255	-96.6%

Source: IPM simulations by ICF.

uncovered sources have an emissions rate below the rate standard. This result is likely driven by the response of relatively clean natural gas plants in IPM.[25]

Seventh, the incremental emissions reductions from the carbon adder are larger under the rate-based CPP than under the mass-based CPP, for example under the rate-based CPP with a 50% SCC the emissions reductions are 95 MMT in 2030, relative to the rate-based/no adder case, whereas the emissions reductions are only 37 MMT for a 50% SCC adder under mass-based regulation. There are several mechanisms that produce this additionality. First, for regions heavily dependent on federal coal, the relatively higher coal price incentivizes natural gas and renewables. For those regions, the shadow price of emissions (the IPM estimate of the value of the CPP tradable permit) falls, and in the more extreme cases falls to zero. At a zero shadow price for CPP permits, the CPP is no longer binding and emission rates are below the CPP standards in those regions.[26] Second, even when each state's emission rate is binding at the CPP standard, the change in relative prices induces shifts in production across states, both within permit trading regions and across regions: because the relative price of coal generation increases with the adder, generation shifts from coal-using states (with high CPP standards) to states with renewable and gas generation (and lower CPP standards). This compositional shift further reduces emissions. Third, even when the CPP is binding, the carbon adder slightly reduces total electricity generation, so emissions fall.[27] Note that the second and third channels are not present under the mass-based CPP.[28]

Eighth, in the IPM simulations the emissions reductions from the carbon adder occur sooner than those from the CPP (Figure 9), so that cumulative emissions reductions by 2030 are estimated to be higher under the 100% SCC carbon adder with no CPP than under either the mass- or rate-based CPP with no carbon adder. The reason for this acceleration of emissions

[25] Under the CPP, the two uncovered sources are small gas combustion turbines, which are currently unregulated, and new natural gas combined cycle plants, which are regulated under Section 111(b) of the Clean Air Act. In the long run the latter source is likely to be larger than the former.

[26] The shadow price is zero for the North Central and West regions by 2050 in the CPP/50% SCC case, and by 2030 in the CPP/100% SCC case.

[27] Although final electricity demand is constant, cross-region exports of coal-fired power declines, reducing transmission losses, and in addition with the carbon adder more hydro power is imported from Canada; the decline in generation reduces emissions under a rate standard but not under a mass standard. This channel would be more important if total demand had been modeled as price sensitive.

[28] See Bushnell, Holland, Hughes, and Knittel (2015) for a detailed treatment of compositional shift under rate- and mass-based CPP implementations with state level standards and trading.

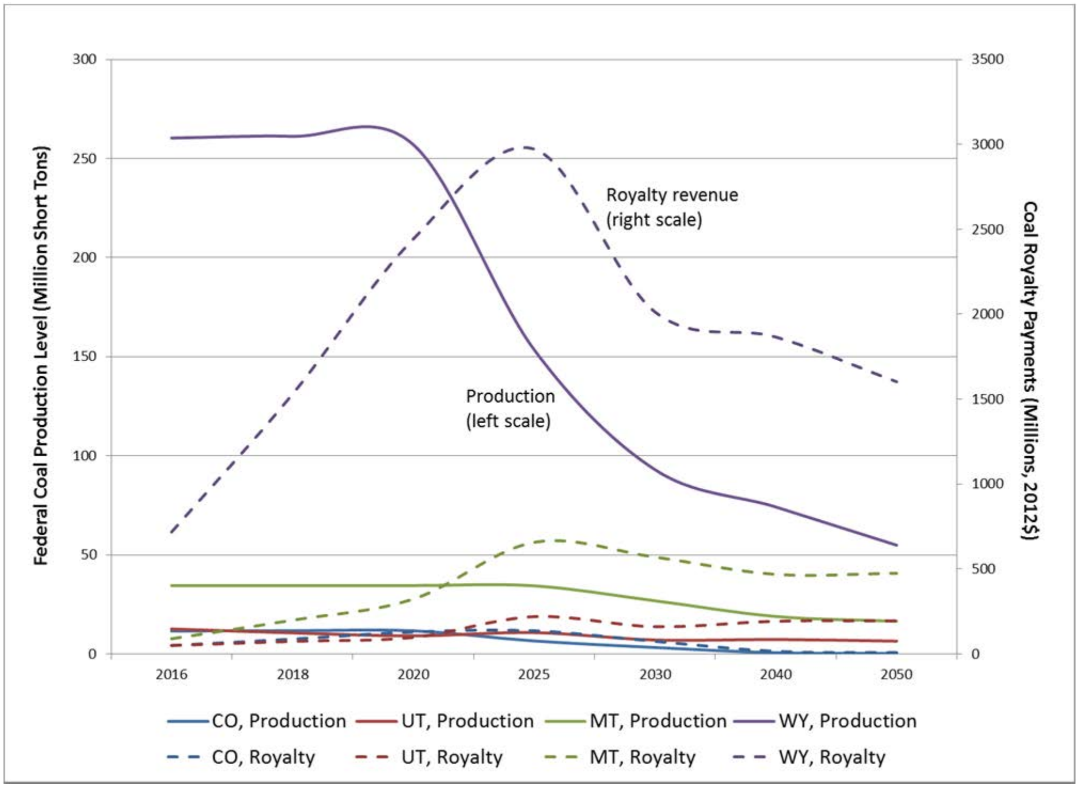
reductions is in part that the phased-in carbon adder provides additional incentives for building new (uncovered, cleaner) NGCC under the carbon adder/no CPP scenario than under the mass- or rate-CPP/no carbon adder scenarios.

The results under the secondary base case (which, among other differences, has lower baseline coal supply costs) are broadly similar to those under the primary base case. Because baseline emissions are higher in the secondary base case, the reductions arising from the CPP (without upstream regulation) are larger than in the primary base case. Similarly, emissions reductions arising from upstream regulation (no CPP) are larger in the secondary than primary case. In the presence of the CPP, the additional effect of the carbon adder on emissions and coal production is somewhat less under the secondary base case than under the primary base case. The mechanism driving this difference is that in the secondary base case, the cost of coal including the adder is less than in the comparable primary base case so that there is somewhat less substitution away from federal coal and the mechanisms described in the previous paragraphs are somewhat less potent.

It is also of interest to see the effects of a carbon adder on total royalty receipts, where total royalties are the sum of the usual 12.5% royalty plus the carbon adder. In principle total royalty receipts could either increase or decrease, relative to the no-adder case. As shown in Figure 10 for the 20% SCC case (mass-based CPP) for the four Western states, gross royalties increase substantially as the adder is phased in. For example, by 2025 annual royalty receipts in Wyoming increase to nearly $3 billion for the 20% SCC adder under mass-based CPP, compared to just over $300 million in the no SCC/mass-based CPP base case, even though production declines by nearly one-quarter as a result of the adder. Increases in royalty receipts in Wyoming, Montana, and Utah are sustained through 2050. In the 100% SCC adder case, royalty receipts initially increase but as production falls to near zero, receipts eventually fall below what they would be in the no-adder case.[29]

[29] These royalty receipt calculations were computed under the secondary base case.

Figure 10. State revenues (right scale, solid) and coal production (left scale, dash): mass-based CPP with 20% SCC adder



Notes: State revenues are calculated as half of total royalty receipts, where the total receipt is the sum of the current 12.5% federal royalty and the carbon adder. Based on IPM simulations by ICF.

We also considered policies in which federal coal leases were subject to tonnage production caps but no royalty adder. The two production limit scenarios considered are (i) ramping down coal production on federal lands to 50% of current levels, and (ii) ramping down entirely, with a 20-year phase-in. This analysis was conducted only under the secondary base case. Table 4 compares the results of the two production cap cases to the 20% and 100% SCC royalty adder cases, as well as the no-upstream policy case, all in the presence of the mass-based SCC. Because of the longer ramp-in time used in the production limit scenarios, the comparisons are for 2040. As can be seen in Table 4, the results for the no new leases case and the 100% SCC case yield similar long-run prices (wholesale electricity prices and tradeable permit prices) and quantities (emissions, coal production, and generation mix). This is consistent with the results

Table 4 Comparison of Upstream Policies under Mass-based CPP Prices and quantities in 2040					
	No new upstream policy	Carbon royalty adder		Tonnage production cap	
		20% SCC	100% SCC	50% production cap	No new leases or renewals
Emissions (MMT)	1,672	1,653	1,622	1,665	1,631
PRB prodn (MST)	266	171	20	232	42
Total coal prodn (MST)	763	730	661	756	678
Wholesale electricity price ($/MWh)	$68.67	67.97	$65.08	$68.42	$64.83
Allowance price					
North Central	$29.42	$22.53	$9.03	$27.13	$7.81
South Central	$29.68	$22.07	$4.41	$27.39	$5.21
Southeast	$31.24	$31.09	$29.67	$30.88	$29.17
Generation (1000 GWh)					
Solar + Wind	466	433	373	456	393
New NGCC	1,184	1,280	1,472	1,215	1,400

All results are computed under the secondary base case and assuming the mass-based CPP is in place. The tonnage production caps assume a 20 year linear phase-in. Source: IPM simulations by ICF.

from the simple static model in Section 3.5 that indicate that the price and rate regulation achieve similar results absent uncertainty. Comparing the results for the 20% SCC and the 50% production cap cases indicates that the 50% production cap is less tight than the 20% SCC in the presence of the mass-based CPP, mainly because coal production (PRB and total) is reduced substantially by the mass-based CPP absent upstream regulation. One difference between the production cap and carbon adder policies is that the carbon adder generates substantial additional royalties (Figure 10), whereas gross royalty receipts decline with production under the cap.

6. Discussion and Conclusions

The quantitative estimates based on the IPM runs have several caveats. The analysis is partial equilibrium and does not allow for response of total electricity demand to changing prices. Our results are directionally consistent among the two differing sets of baseline assumptions, giving confidence that our findings are robust and not overly sensitive to changes in energy market parameters. However, dramatic changes in future energy prices or departures from other core assumptions (e.g., cost trajectories for renewables), could have an important influence on the results. Such potential developments could be incorporated into the IPM, but that is beyond the scope of this research. In addition, although IPM has the strength of a high level of detail about regional variations in demand and supply, fuel decisions, and new capacity planning, its assumption of perfect foresight abstracts from price and policy uncertainty.

Although several variations of CPP implementation are examined in this study, the actual details will likely differ from those modeled here. In addition, the policy assumptions used in these simulations are those available as of October 2015. These assumptions do not include the five-year extension of the wind production tax credit and the solar investment tax credit passed at the end of 2015, and therefore arguably understate likely new wind and solar capacity in the 2016-2021 period and thus likely overstate both baseline coal demand and baseline allowance prices. To the extent that economic developments in wind and solar make the CPP non-binding by 2030 as EPA officials have suggested, the effects of the royalty adder would be towards the higher end of the emissions reduction estimates in Section 4.

With these caveats in mind, the main findings of IPM analysis are that an upstream policy of a royalty adder could provide substantial emissions reductions in the absence of the CPP, or if it is implemented but nonbinding; if the CPP is binding, the royalty adder would reduce CPP compliance cost (by reducing the allowance price) and would result in some additional emissions reductions by reducing leakage. Although non-federal coal production increases for a period of time in response to the carbon adder driven increase in the price of federal coal, this substitution is limited by the economically preferable option of switching to gas and renewables.

Appendix

This appendix sketches the derivation of the comparative statics expressions in Section 3.3 (cap-and-trade with uncovered sources). Let $\dot{p}$ denote *dp*/*dr*, etc. Differentiating with respect to *r* the five first order conditions for the constrained maximization (16), the consumer's first order condition $p = U'(Q)$, and the identity $Q = q_{FC} + q_{NFC} + q_O + q_U$ yields,

$$0 = \dot{p} - C''_{FC}\dot{q}_{FC} - \dot{t} - 1 \tag{A.1}$$

$$0 = \dot{p} - C''_{NFC}\dot{q}_{NFC} - \dot{t} \tag{A.2}$$

$$0 = \dot{p} - C''_{O}\dot{q}_{O} - \lambda\dot{t} \tag{A.3}$$

$$0 = \dot{p} - C''_{U}\dot{q}_{U} \tag{A.4}$$

$$0 = \dot{q}_{FC} + \dot{q}_{NFC} + \lambda\dot{q}_{O} \tag{A.5}$$

$$0 = \dot{p} - p'\dot{Q} \tag{A.6}$$

$$\dot{Q} = \dot{q}_{FC} + \dot{q}_{NFC} + \dot{q}_{O} + \dot{q}_{U}, \tag{A.7}$$

where $p' = U''(Q)$. Equations (A.1) – (A.7) are a system of seven equations in seven unknowns. It is convenient to solve the system by reducing it to two equations in two unknowns, $\dot{p}$ and $\dot{t}$. First, premultiply (A.1) – (A.4) respectively by $C''_{NFC}C''_{O}C''_{U}$, $C''_{FC}C''_{O}C''_{U}$, $C''_{FC}C''_{NFC}C''_{U}$, and $C''_{FC}C''_{NFC}C''_{O}$, sum the result, use the identity (A.7) to eliminate the individual quantities, then use (A.6) to eliminate $\dot{Q}$. Second, premultiply (A.1) – (A.3) respectively by $C''_{NFC}C''_{O}$, $C''_{FC}C''_{O}$, and $\lambda C''_{FC}C''_{NFC}$, sum the result, and use (A.5) to eliminate the individual quantities. The result is a pair of equations for $\dot{p}$ and $\dot{t}$:

$$\begin{aligned}0 &= \left(C''_{NFC}C''_{O}C''_{U} + C''_{FC}C''_{O}C''_{U} + C''_{FC}C''_{NFC}C''_{U} + C''_{FC}C''_{NFC}C''_{O}\right)\dot{p} \\ &\quad -\left(C''_{NFC}C''_{O}C''_{U} + C''_{FC}C''_{O}C''_{U} + C''_{FC}C''_{NFC}C''_{U} + \lambda C''_{FC}C''_{NFC}C''_{O}\right)\dot{t} - C''_{NFC}C''_{O}C''_{U}\end{aligned} \tag{A.8}$$

$$0 = \left(C''_{NFC}C''_{O} + C''_{FC}C''_{O} + \lambda C''_{FC}C''_{NFC}\right)\dot{p} - \left(C''_{NFC}C''_{O} + C''_{FC}C''_{O} + \lambda^2 C''_{FC}C''_{NFC}\right)\dot{t} - C''_{NFC}C''_{O}. \tag{A.9}$$

Equations (A.8) and (A.9) can be solved to yield (17) and (18). Equation (23) is equation (A.6). The derivatives for the individual quantities obtain by direct substitution, for example (19) obtains by substituting (17), (18), and (23) into (A.1).

Section 3.1 asserts that the comparative statics using supply and demand is equivalent to the comparative statics from the firm and consumer optimization problems. The argument is sketched here for the mass cap with uncovered sources. Let the supply curve of federal coal be $S_{FC}(.)$, where the argument is the net price received for electricity generated by federal coal, which is $p - t - r$. Similarly let $S_{NFC}(.)$, $S_O(.)$, and $S_U(.)$ denote the supply curves for the other fuels. The market equilibrium conditions that supply equals demand $D(p)$ and that the mass cap is binding are,

$$S_{FC}(p-t-r)+S_{NFC}(p-t)+S_O(p-\lambda t)+S_U(p)=D(p) \tag{A.10}$$

$$S_{FC}(p-t-r)+S_{NFC}(p-t)+\lambda S_O(p-\lambda t)=\bar{E}\ . \tag{A.11}$$

Taking the total differential of (A.10) and (A.11) with respect to r yields,

$$0=\left(S'_{FC}+S'_{NFC}+S'_O+S'_U-D'\right)\dot{p}-\left(S'_{FC}+S'_{NFC}+\lambda S'_O+S'_U-D'\right)\dot{t}-S'_{FC} \tag{A.12}$$

$$0=\left(S'_{FC}+S'_{NFC}+\lambda S'_O\right)\dot{p}-\left(S'_{FC}+S'_{NFC}+\lambda^2 S'_O\right)\dot{t}-S'_{FC}\ , \tag{A.13}$$

where $S'_{FC}=dS_{FC}(p)/dp$, etc. Substitution of $S'_{FC}=1/C''_{FC}$, etc., and $D'=1/p'$ (i.e., the slope of the supply curve is the reciprocal of the slope of the marginal cost curve, and the slope of demand is the reciprocal of the slope of marginal utility of consumption) into (A.12) and (A.13) respectively yields (A.8) and (A.9).

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