Climate Royalty Surcharges

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Abstract

Concerns about climate change have led to calls for reforming or eliminating the extensive US federal fossil fuel leasing program. One proposed reform is adding a climate surcharge to the existing royalty rate, but what precisely that surcharge should be is unclear. We consider determining this surcharge by maximizing revenue, maximizing welfare, or setting royalties to achieve 80% of the emissions reductions of an outright leasing ban. We estimate that all three approaches would lead to meaningful declines in global emissions, and the first two would substantially increase royalty receipts, which are split with the state of production.

Key words: extraction royalties, social cost of carbon, Federal minerals program
JEL codes: Q54, Q58, Q35, Q38, H23

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Starting in the 19th century for coal, and in the 20th century for oil and gas, the US government promoted fossil fuel extraction from federal lands. Federal fossil fuel leasing helped drive settlement of the American West, provided a secure domestic supply of energy to a growing nation, and created jobs and wealth. In 2019, production on federal lands comprised 40% of domestic coal production, 22% of domestic oil production, and 12% of domestic natural gas. Now, however, we understand that CO_2 emitted by burning fossil fuels is the primary driver of climate change. As a result, there have been calls to rethink the federal government's role in fossil fuel leasing, including potentially reforming or ending the fossil fuel leasing program.

One proposed reform is to adjust the royalty rate assessed on federal fossil fuels to account for the climate impacts of using those fuels.[1] Legal analysis suggests that such a royalty adjustment can be implemented administratively under existing legal authorities (Krupnick et al. 2016, Hein 2018). Beyond that, however, there are the basic economic questions of what economic principles could be used to determine a climate-based increase in royalties, what the resulting rates would be quantitatively, and what would be the effects on CO_2 emissions and royalty revenues.

In this paper, we tackle these questions regarding the economics of a climate-based increase in the federal fossil fuel royalty rate. Because there is essentially no demand for new coal leases, we focus on federal oil and gas leasing. Also, because a decrease in federal production will in general be partially offset by an increase in non-federal production, we focus on net emissions reduction that account for this leakage.

Carbon damages are typically measured in dollars per ton of CO_2, but federal royalties are assessed as a percentage of extraction revenue. Because the prices and carbon intensities of oil and gas differ, the same carbon fee (\$/ton CO_2) would imply different climate royalty surcharges (measured in percentage points) for oil and for gas. We therefore consider three options for incorporating climate costs: applying the same per-ton carbon fee to both oil and gas, which implies different royalty surcharges; applying the same climate royalty surcharge, which implies different carbon fees; or determining the carbon fee (or royalty surcharge) separately for oil and gas.

We propose and evaluate three principles for determining the carbon fee or, alternatively, the climate royalty surcharge.

One principle is to maximize royalty revenue. Using the oil and gas production model in Prest (forthcoming), we find that total royalties follow a "Laffer curve": at low values of the climate

[1] For example, in January 2021, President Biden issued Executive Order 14008, which, among other things, instructed the Secretary of the Interior to consider "whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs" (White House 2021).

royalty surcharge, total receipts increase, but they eventually plateau then decline. Because royalty revenues are split equally between the federal government and the state of extraction, the revenue-maximizing rate maximizes the funds going to states to address the challenges that fossil-fuel extraction communities will face in the broader energy transition. Maximizing royalty revenue also aligns with the long-standing principle of obtaining value for the taxpayer from selling federally owned resources.[2]

The second principle for choosing the royalty surcharge is to maximize social welfare, which includes the climate externality. Welfare maximization is a standard principle of optimal taxation theory (e.g., in the context of Pigovian taxation, Sandmo 1975 and Nordhaus 1982).

The third principle is that a royalty rate schedule be chosen to phase out new federal fossil fuel leasing by a specified date, to be consistent with a net-zero emissions target date. As we discuss, there are questions about whether the existing legal authorities governing the minerals leasing program authorize shutting down the program entirely through administrative means. We therefore approach this quantity-restriction principle by finding the fee, or surcharge, that achieves 80% of the emissions reductions that would be achieved by a total cessation of new fossil fuel leases.

We find that, if a single climate royalty surcharge is applied to both oil and gas, revenues are maximized by a surcharge of approximately 36%. Currently, oil and gas royalties are 12.5% onshore (18.75% offshore), values meant to compensate the taxpayer for the value of the extracted fuels. Adding the climate royalty surcharge to the 12.5% onshore taxpayer compensation rate yields a total federal royalty rate of 48.5%. We estimate that this would generate approximately \$5 billion of additional royalty revenues annually on average from 2020-2050, and global emissions would fall by roughly 34 million metric tons of CO_2-equivalent greenhouse gases (MMTCO_2e) per year, approximately 42% of the reductions achieved by a leasing ban. Further reducing emissions from the revenue-maximizing rate to the level arising from a leasing ban, reduces total royalty revenues by approximately \$127-\$220 per ton of additional CO_2e abated.

This revenue-maximizing common royalty surcharge is bracketed by welfare-maximizing common royalty surcharges of 19% and 45%, respectively computed using a \$50/ton CO_2 Social Cost of Carbon (SCC; the interim Biden administration central value is \$51) and a \$125/ton CO_2 SCC (the New York State value, which uses a 2% discount rate instead of the 3% rate used for the interim Biden value). Also, we estimate that a common royalty surcharge of approximately 70% would lead to a reduction of emissions of 80% of what would be achieved by a cessation of

[2] CEA (2016) provides additional discussion of setting royalty rates to maximize revenue and estimates the revenue-maximizing royalty rate for new federal coal leases.

all new leasing. There is considerable uncertainty around this 80%-reduction estimate, however, because it extrapolates well outside the range of the data on which our estimates rely.

1. The Federal Fossil Fuel Leasing Program

Federal fossil fuel leasing is governed by the Mineral Leasing Act of 1920 (MLA) and the Federal Land Policy Management Act of 1976 (FLPMA). The fossil fuel leasing program is administered by the Department of the Interior, with the Bureau of Land Management (BLM) managing onshore leasing and the Bureau of Ocean Energy Management (BOEM) managing offshore leasing.

Since the 1920s, the federal royalty rate for onshore oil and gas has been at the 12.5% floor established by the MLA. In 2008, deepwater offshore rates for new drilling leases were increased from 12.5% to 16.67%, then raised further in 2009 to 18.75%,[3] where they currently stand for drilling in depths exceeding 200 meters. Royalty rates are one of the terms of a lease. Federal oil and gas leases have a primary lease period of 10 years, with 2-year extensions. Once producing, a lease is extended indefinitely so long as wells on it produce oil or gas.

Royalties are the primary, but not sole, source of US government revenues from federal fossil fuel leasing. For onshore leases, tracts for potential mineral leasing are either identified by the BLM or nominated by private parties. Mineral rights to those tracts are first auctioned competitively to the highest bidder. If BLM receives at least one bid above the $2 per acre statutory minimum, then BLM awards the bid to the highest bidder. If no bid of $2 per acre is received, BLM makes the tract available on a first-come, first-serve basis at that minimum bid. The upfront payments are referred to as bonus bids. In addition, the BLM receives small amounts of rental fees.[4]

Royalty payments account for the vast majority of receipts under the federal fossil fuel leasing program. Of the three primary components of revenue – royalties, bonus bids, and rents – royalties comprised between 83% and 93% annually. In fiscal year 2019, the oil and gas program received $7.745 billion in royalties, of which 85% was from oil, $496 million in bonus bids, and $130 million in rents.

In 2016, the Department of the Interior issued a moratorium on new leases while it conducted a programmatic environmental review of the coal leasing program (DOI 2017). The DOI suggested a royalty surcharge, or adder, as one way to account for climate damages from burning the fossil fuels. Legal analyses conclude that the Department of the Interior has the legal authority to adjust royalties to account for climate damages, both for coal (Krupnick et al. 2016)

[3] Congressional Research Service (2015).
[4] See GAO (2020) for details.

and for oil and gas (Hein 2018). Note however that existing leases, once granted, confer legally binding property rights and royalty rates, so all policies we consider apply only to new leases.

2. The Economics of Fossil Fuel Leasing Reform[5]

A climate royalty surcharge adjusts the price of the extracted fossil fuel to reflect the damages caused by burning it, that is, it partially or completely internalizes the carbon externality. The conventional framework for determining royalties – ensuring the taxpayer a fair return – does not include externalities from use, so any climate-based royalty adjustments would be in addition to the current royalty rate.[6]

A climate royalty surcharge would increase the cost of production on federal lands and waters, making some drilling projects unprofitable, thereby reducing production on federal lands. The decrease in production tightens total supply, increasing the market prices of oil and gas. This increase in price would pull in additional nonfederal production, partially offsetting the decrease in federal production. Because demand falls at the higher price, the increase in nonfederal production is less than the decline in federal production. From the perspective of reducing CO_2 emissions, a climate royalty surcharge results in "leakage," because a fraction of the decline in federal production is offset. The leakage rate λ is the fraction of emissions reductions from federally produced oil and gas that is offset by increased production elsewhere. The more elastic is supply, all else equal, the larger is λ; the more inelastic is demand, the larger is λ.

There are two ways to incorporate climate costs into royalties. The first, which we refer to as a carbon fee, is by a fee assessed per unit of production (e.g., dollars per barrel of oil), where the fee is based on the monetized damages from burning that fuel, which is in turn based on its carbon content. The second, which we term a climate royalty surcharge, is an *ad valorem* assessment, as a percentage of sales. The carbon fee framework aligns with conventional applications of carbon pricing, whereas the climate royalty surcharge aligns with the current *ad-*

[5] The economics literature on incorporating climate considerations into fossil fuel leasing reform consists of Gerarden, Reeder, and Stock (2020), Erickson and Lazarus (2018), and Prest (forthcoming). Gerarden, Reeder, and Stock (2020) consider climate royalty surcharges in the federal coal program and their interaction with demand-side CO_2 regulation. Erikson and Lazarus (2018) estimate potential reductions from the cessation of coal and oil (but not gas) leasing by 2030, using a static constant-elasticity model that drew from estimates from the literature. Prest (forthcoming) developed an eight-component combined model oil and gas leasing, where each component is separately econometrically parameterized, to estimate the effect of percentage-based and SCC-based royalty surcharges on emissions, production, and royalties annually through 2050. This research fits into a growing body of research on supply-side climate policies, see Lazarus and van Asselt (2018) for a survey.

[6] Royalty rate determination for maximizing taxpayer return is part of the theory of contracting and regulation with asymmetric information. A textbook treatment is Laffont and Tirole (1994), which connects auctions and regulation under asymmetric information and moral hazard. For a review of the theoretical literature on royalty auctions, see Skrzypacz (2013). Haile, Hendricks, and Porter (2010) summarize the relation between auction structure and government revenues. For additional references to auction theory in the context of US oil and gas leasing (a bonus bid auction not a royalty auction), see Compiani, Haile, and Sant'Anna (2020).

valorem approach to federal royalties. Given a base price, a carbon fee can be recast as a climate royalty surcharge and vice versa.

2.1 Carbon fees

Basic economic principles provide clear guidance about setting carbon fees to address the climate externality. Absent leakage – for example, if a fee (or tax) could be applied to all fossil fuels, federal and nonfederal – the optimal policy in a standard model of welfare maximization is to set the carbon fee equal to the marginal value of the avoided climate damage (e.g., Nordhaus 1982). The marginal damage is the net present value of current and future monetized climate damages in units of dollars per ton CO_2, that is, the Social Cost of Carbon (SCC). With leakage, the welfare-maximizing carbon fee equals the marginal *net* damages avoided after accounting for offsetting leakage. These net climate damages avoided are (1-λ)SCC for each ton of direct (or gross) emissions reductions, where λ is the leakage rate. Thus, the carbon fee τ, in dollars per ton CO_2e, to apply to the covered fuel is τ = (1-λ)SCC (Holland 2012).

The situation is more complicated when there are interactions in the supply of fuels, as is the case here because some wells produce both oil and gas. For example, a fee on oil only, but not on gas, would reduce gas production because of reduced drilling of wells that produce both oil and gas. Because of co-production and different leakage rates for the different fuels, the welfare-maximizing carbon fees for oil and gas will differ.

The derivation of these optimal fees is a straightforward extension of the model in Holland (2012) to multiple fuels. Our setup is standard (e.g., as in Hoel 1996, Holland 2012, and Fæhn et al. 2017) with static utility, cost, and damage functions, extended to *n* fuels, with leakage and co-production. Each fuel has covered (superscript *c*) and uncovered (*u*) production. The *n*-vector of production of covered fuels is $Q^c = (q_1^c, ..., q_n^c)'$ and uncovered fuels is $Q^u = (q_1^u, ..., q_n^u)'$; the vector of total production is $Q = Q^c + Q^u$. The representative consumer derives utility $U(Q)$ from consumption of the fuels, where consumption equals production. The cost function for producing uncovered fuels is $C^u(Q^u)$. For covered fuels, the cost function is $C^c(Q^c, .)$, where the final argument is the carbon fee or royalty surcharge. This cost function includes private costs from carbon fee/royalty payments.

Burning Q_i produces emissions $E_i = e_i Q_i$, where e_i is the emissions intensity of fuel *I* (e.g., tons CO_2e/barrel), with vectors of covered, uncovered, and total emissions being E^c, E^u, and $E = E^c + E^u$. Covered emissions are $E^{tot,c} = e'Q^c$, uncovered emissions are $E^{tot,u} = e'Q^u$, and total emissions are $E^{tot} = e'Q$, where $e = (e_1, ..., e_n)'$. External damages from emissions are $D(E^{tot})$.

With separate carbon fees for oil and gas, the social planner chooses the vector of carbon fees τ to maximize social welfare:

$$\max_{\tau} W(Q) = U(Q) - C^c(Q^c, \tau) - C^u(Q^u) - D(E^{tot}) + \tau' E^c, \tag{1}$$

where receipts from the carbon fee are added back into welfare because they are subtracted off in the covered cost function (those costs represent a transfer payment). The first order condition for τ is,

$$\begin{aligned} &\frac{\partial U}{\partial Q'}\left(\frac{\partial Q^c}{\partial \tau'} + \frac{\partial Q^u}{\partial \tau'}\right) - \frac{\partial C^c(Q^c,\tau)}{\partial Q^{c'}}\frac{\partial Q^c}{\partial \tau'} - \frac{\partial C^c(Q^c,\tau)}{\partial \tau'} - \frac{\partial C^u(Q^u,\tau)}{\partial Q^{u'}}\frac{\partial Q^u}{\partial \tau'} \\ &-\theta\frac{\partial E^{tot}}{\partial \tau'} + E^{c'} + \tau'\frac{\partial E^c}{\partial \tau'} = 0, \end{aligned} \tag{2}$$

where $\theta = \mathrm{d}D/\mathrm{d}E^{tot}$ is the marginal damage. Market clearing implies that $\frac{\partial U}{\partial Q} = \frac{\partial C^c(Q^c,\tau)}{\partial Q^c} = \frac{\partial C^u(Q^u)}{\partial Q^u}$, and the envelope theorem implies that $\partial C^c(Q^c,\tau)/\partial\tau = E^c$.

Thus, (2) simplifies to $\tau'\frac{\partial E^c}{\partial \tau'} = \theta\frac{\partial E^{tot}}{\partial \tau'}$, so

$$\tau = \left(\frac{\partial E^{c'}}{\partial \tau}\right)^{-1}\frac{\partial E^{tot}}{\partial \tau}\theta. \tag{3}$$

Expression (3) generalizes Holland's (2012, equation (5)) expression for a single fuel with partial coverage to multiple fuels. In the case of a single fuel, (3) reduces to $\tau = (1-\lambda)\theta$, where λ is the leakage rate and θ is the marginal monetized damages of emissions, that is, the social cost of carbon (SCC).

When there is no substitution in production or consumption across fuels, the welfare-maximizing fee for each fuel simplifies to $\tau_i = (1-\lambda_i)\theta$, where λ_i is fuel i's leakage rate. In general, (3) contains cross-terms, so the welfare-maximizing vector of fees depends on leakage both within and across fuels.

2.2. Implied climate royalty surcharge

Historically, federal fossil fuel royalties have been a percentage of sales, and there may be legal or administrative reasons to continue an *ad valorem* assessment. A per-ton CO_2e carbon fee τ can be converted to an *ad-valorem* climate royalty surcharge r using the emissions intensity and price. For example, for oil, let P_{oil} denote a benchmark price. Then the climate royalty surcharge,

r_{oil}, corresponding to a carbon fee τ_{oil}. is $r_{oil} = \tau e_{oil}/P_{oil}$, where e_{oil} is the emissions intensity of oil (tons CO_2e per barrel).

Because oil and gas have different carbon intensities and prices, a single carbon fee implies different values of the carbon royalty surcharge for oil and gas. Historically, however, royalty rates have largely been the same for oil and for gas for 100 years, and there might be legal or administrative reasons to the same rate for each. Whether the royalty surcharges differ across fuels or not, welfare maximization implies that the climate royalty surcharge equals its marginal climate benefit.

2.3. Determining the climate royalty surcharge

The effect of federal leasing reform on emissions is one important consideration, but so is the effect of that reform on communities traditionally supported by fossil fuel extraction on federal lands. About half of federal onshore royalty revenues is shared with the states. As the energy transition progresses, states and communities reliant on federal extraction will face fiscal and related challenges, that revenues from a climate royalty surcharge could help address. With these observations in mind, we consider three principles for setting the climate royalty surcharge.

The first is to choose the climate royalty surcharge to maximize royalty revenues. This approach maximizes extraction revenues returned to states.[7]

The second is to choose the climate royalty surcharge to maximize social welfare. In general, this entails choosing the policy instrument(s) so that the marginal cost equals its marginal benefit in avoided climate damages. In practice, oil and gas face a common royalty rate, so we consider the social planner's problem of choosing a single common royalty rate *r* to maximize welfare:

$$\max_{\tau} W(Q) = U(Q) - C^c(Q^c, r) - C^u(Q^u) - D(E^{tot}) + rY^c. \tag{4}$$

The first order condition for *r* is,

$$\begin{aligned} &\frac{\partial U}{\partial Q'}\left(\frac{\partial Q^c}{\partial r} + \frac{\partial Q^u}{\partial r}\right) - \frac{\partial C^c(Q^c, r)}{\partial Q^{c\prime}}\frac{\partial Q^c}{\partial r} - \frac{\partial C^c(Q^c, r)}{\partial r} - \frac{\partial C^u(Q^u, r)}{\partial Q^{u\prime}}\frac{\partial Q^u}{\partial r} \\ &-\theta\frac{\partial E}{\partial r} + Y^c + r\frac{\partial Y^c}{\partial r} = 0. \end{aligned} \tag{5}$$

Using market clearing conditions and the envelope theorem as above yields,

[7] CEA (2020) calculates a revenue-maximizing royalty adjustment for federal Powder River Basin coal.

$$r\frac{\partial Y^{c}}{\partial r}=\frac{\partial E}{\partial r}\theta\,, \tag{6}$$

which defines an optimal royalty rate r. Equation (6) has an intuitive interpretation: the marginal cost of further increasing the royalty surcharge, which is the foregone revenue (the royalty rate times the loss in the market value of covered production), equals the marginal benefit, which is the net change in emissions valued at the SCC.

In the special case in which the change in revenues is dominated by the change in quantity produced, not the change in market prices, then we can derive the approximation,

$$r\approx\frac{e'\dfrac{\partial Q}{\partial r}\theta}{P'\dfrac{\partial Q^{c}}{\partial r}}\,. \tag{7}$$

In the approximation (7), the royalty rate is proportional to the SCC, scaled by the emissions-weighted average of the marginal change in production. In the case of a single fuel, (7) simplifies to $r = e\,(1-\lambda)\theta/P$, which is the optimal carbon fee with leakage re-expressed as a fraction of the sales price of the fuel.

A third potential approach to leasing policy is to specify emissions reduction target. Much of the world has adopted a net-zero targeting approach to guiding climate policy, with target dates of 2050 (EU) or 2060 (China). Cognizant of the legal question of whether fossil fuel leasing can be ended administratively under FLPMA, we consider a royalty surcharge that does not entirely shut down the program but achieves 80% of the global emissions reductions achieved by a ban on new leasing.

2.4. Interaction with lease auctions

An increase in the federal royalty rate would interact with the federal competitive auction process, plausibly leading to lower bonus bids at auction. In practice, these interactions are likely to have a limited effect on projected total revenues. From 2013 to 2019, oil and gas royalty revenues averaged 7.5 times bonus bids; in FY 2019, oil and gas royalty receipts were $7.745 billion, whereas bonus bids were only $496 million. Thus, the scope for a decline in bonus bids offsetting an increase in royalties is limited.

3. Estimated Effects of an Oil and Gas Climate Royalty Surcharge on Production, Emissions, and Revenue

We now turn to a quantitative assessment of the effect of a climate royalty surcharge on production, emissions, and revenue for new oil and gas leases; we exclude coal because of the absence of current and anticipated future demand for new coal leases.

Our calculations are based on Prest's (forthcoming) model of oil and gas production on federal lands. The model has three stages of production (drilling, well completion, and production) for wells differentiated by federal/nonfederal, oil-directed/gas-directed, and onshore/offshore, for a total of eight well types. An important parameter in assessing the effect of the royalty surcharge is the elasticity of demand. Historically, the demand for oil has been inelastic because there are few alternatives to gasoline, diesel, or jet fuel. Looking ahead, as alternatives like electric vehicles become more common, oil demand could become more elastic. Similarly, in 2019, 36% of natural gas was used for electricity, and as renewable generation increases the electricity demand for gas could become more elastic. For these reasons, we use low demand elasticities as our base case, but also consider a scenario with more elastic demand as in Prest (forthcoming).[8] For the base case, we use demand elasticities of -0.2 for both oil and gas, based on several empirical estimates and surveys of the literature (Erickson and Lazarus 2018, Hamilton 2009, Bordoff and Houser 2015, Arora 2014, and Auffhammer and Rubin 2018). For the high elasticity case, we use estimates from the higher end of the literature: -0.51 for oil (Balke and Brown 2018, Metcalf 2018, Allaire and Brown 2012) and -0.42 for gas (Hausman and Kellogg 2015, Metcalf 2018).

We first consider assessing production on new leases the same carbon fee for oil and gas, expressed in 2020 dollars per metric ton of CO_2. Table 1 translates selected per-ton fees into assessments expressed in the native price units of the fuel ($/barrel for oil, $/thousand cubic feet, or mcf, for gas). For comparison purposes, these rates are also provided for coal, although coal is not included in subsequent calculations.

The left panel of Figure 1 summarizes the effect of a carbon fee on total royalty revenues (base royalty rate plus carbon fee) and CO_2e emissions, for both base (low) and high elasticities. The business-as-usual (BAU; no new policy) scenario corresponds to the carbon fee equaling zero; under this assumption, average oil and gas royalties are projected to be $9.2 billion/year on average from 2020-2050. The figure also shows annual average revenues under a leasing ban.

[8] The model in Prest (forthcoming) combines a detailed, econometrically calibrated simulation model of US supply with a rest of world (ROW) module with responsive supply based on the IEA 2019 World Energy Outlook. This accounts for cross-price effects on US supply (e.g., how oil prices affect both oil production and gas co-production, and vice versa), dynamics (how changes to prices or policies today affect drilling and production over time), and leakage (e.g., how changes in production on federal lands if offset by increases from nonfederal and foreign suppliers). For details, see Prest (forthcoming).

Under the new leasing ban, production continues under existing leases, which generates royalties, and the 30-year average royalties are $4.0 billion/year. Emissions are shown as reductions from BAU, as a percentage of the reductions under a leasing ban.

Total revenues follow a Laffer curve: as the carbon fee increases from zero, total royalty revenues increase, then peak, then decline to below BAU levels, as the decline in production offsets the revenues generated by a higher carbon fee. Total revenues are maximized at a carbon fee of $20 per metric ton CO_2e, above which revenues drop off sharply. At a sufficiently high price, new production drops sharply, so royalties fall below BAU royalties. At their peak, increasing the carbon fee increases average annual royalties by about $4.0 billion compared with BAU. Under current law, about half of this would be distributed to the states and half would be retained by the federal government.

A nuance in this revenue Laffer curve is that it has two peaks, a global maximum at approximately $20/ton CO_2e, in addition to a local maximum at $42. The global peak around $20/ton is associated with gas production declining more rapidly than oil in response to the per-ton carbon fee: as seen in Table 1, a $25 carbon fee is 64% of the price of gas, but only 19% of the price of oil. Because the two fuels have Laffer curve peaks at different values of the carbon fee, the composite Laffer curve has two peaks.

Total emissions fall as the carbon fee increases. For lower values of the carbon fee, the reduction in emissions is steeper than for higher values. The reason for this nonlinear behavior is the same as for the double peak in the revenue Laffer curve: at low levels, the carbon fee reduces both oil and gas production, but at higher levels, gas-directed leasing largely ceases, which shuts off this margin of response to further increases.

The right panel of Figure 1 shows the analogous results for a common royalty surcharge for both oil and gas (as a percentage of revenues). Revenues again follow a Laffer curve, but without the double peak because the common royalty rate implies a smaller carbon charge on gas than on oil. This common rate also results in an approximately linear relationship between the surcharge and emissions reduced. The revenue-maximizing royalty surcharge is 36%.

The results in Figure 1 are insensitive to the demand elasticity. The effect on total emissions depends strongly on the elasticity, however: under a leasing ban, global emissions are estimated to fall by 80 and 139 $MMTCO_2$e/year for the base and high elasticity cases respectively. At the revenue-maximizing carbon fee, emissions reductions are about 36% of the emissions reductions achieved by a leasing ban, corresponding to 29 to 50 $MMTCO_2$e/year in the low elasticity base case and high elasticity cases, respectively. The revenue-maximizing surcharge delivers slightly larger emissions reductions of about 42% of those achieved by a leasing ban.

Figure 2 shows time paths of revenues under a variety of policy approaches, including BAU, a leasing ban, and a selection of alternative policies.[9] Because the carbon fees and surcharges apply to only new leases, the effects of the programs phase in over time. The effects on revenues are within ±$1 billion per year through 2025. The gap widens significantly after 2030.[10]

Table 2 provides results for various comparison policies (BAU, raising onshore royalty rates, and a leasing ban, all in panel a) alongside those for the revenue-maximizing and welfare-maximizing carbon fees and surcharges. The table also shows each policy's climate and revenue effects, where the estimates are for the low elasticity base case.

First, considering the conventional policies, raising the royalty rate for onshore extraction to match the 18.75% rate for offshore oil and gas. This change increases taxpayer receipts somewhat, however the gains in revenues are small compared with the revenue-maximizing rate. The decline in emissions resulting from this alignment of onshore and offshore rates is quite modest. A leasing ban naturally has the largest effect and serves as a point of comparison for the carbon policies in panels b, c, and d.

Panel b shows policies featuring common carbon fees. As previously discussed, the revenue-maximizing common carbon fee is $20/ton. The welfare-maximizing fee depends on the Social Cost of Carbon. The table uses two SCC values: $50/ton, closely reflecting the interim Biden Administration central value (3% discounting) for emissions in 2020 in 2020 dollars, and $125, which uses the same models and assumptions but a 2% discount rate.[11] The welfare-maximizing carbon fees are $14/ton and $34/ton for the two SCC values, bracketing the $20 revenue-maximizing value. Emissions reductions depend strongly on the fee, with the $34/ton fee yielding emissions reductions that are more than 70% of the reductions under a leasing ban. Evidently, imposing the same carbon fee on oil and gas implies quite different climate royalty surcharges for the two fuels.

Panel c considers applying the same climate royalty surcharge to oil and gas, which aligns with historical practice. The revenue-maximizing climate royalty surcharge, 36%, is slightly less than the welfare-maximizing surcharge of 45% when using an SCC of $125/ton CO_2e. The emissions reductions at the welfare-maximizing surcharge are half that of a leasing ban. Compared to a common carbon fee, a common royalty surcharge implies a relatively higher tax on higher-emissions and higher-value oil than on gas. As a result, the revenue-maximizing climate

[9] The policies included are the revenue-maximizing common fees or surcharges, and the welfare-maximizing separate fees with a $50 SCC.

[10] Even under a leasing ban, royalties flatten out over time as wells on existing leasing continue to produce, albeit at declining levels. Revenues under the leasing ban flatten out after 2040. This is the net result of two offsetting factors: production on existing leases declines annually as wells are exhausted, but under this price path, oil and gas prices rise at a similar rate.

[11] https://www.dec.ny.gov/press/122070.html

surcharge results in higher revenues and slightly more emissions reductions than the revenue-maximizing carbon fee.

The top panel of Table 3 presents the effects of distinct oil and gas carbon fees on additional royalty and fee revenues for the base case elasticity. Because of coproduction and the different types of wells, the interaction between the two carbon fees is complex. For a given value of the oil fee, as the gas fee increases, total royalties initially increase, then decline as gas-directed drilling diminishes. With a single common fee, total royalties are maximized at $20/ton CO_2e, yielding royalty revenues of $13.2 B/year. According to Table 3, total revenues could be further increased to $14.5 B/year by imposing higher fee on oil of $40/ton and reducing the gas surcharge to $5/ton.

The bottom panel of Table 3 presents the effect of distinct oil and gas carbon fees on emissions, both for the base case elasticities. The revenue-maximizing carbon fee of $40 for oil and $5 for gas yields similar emissions reductions to the single-fee maximum of $20 in Table 2, 31 $MMTCO_2$e/year compared to 29 $MMTCO_2$e/year. However, the composition of these emissions reductions differs, with a high oil fee and low gas fee placing greater emphasis on reducing oil production, rather than gas.

Panel d of Table 2 summarizes the revenue-maximizing and welfare-maximizing policies with distinct carbon fees. The welfare-maximizing pair of carbon fees depends on the SCC, on direct and cross-price effects, for instance how a fee on oil affects gas through co-production, and on leakage rates. We solve for the optimal price numerically along the grid of oil and gas fees shown in Table 3. At a $50/ton SCC based on a 3% discount rate, the welfare-maximizing fees are about $20/ton for oil and $15/ton for gas. These amount to about $9/barrel of oil and $1/mcf of gas, which in turn are roughly equivalent to a climate surcharge of 15% for oil and 39% for gas. This achieves 29% of the emissions reductions that a leasing ban would achieve and raise $4.2 B/year in revenue above BAU. At a $125/ton SCC, the welfare-maximizing fees are twice as large at about $40/ton for oil and $30/ton per gas, corresponding to climate royalty surcharges of approximately 30% for oil and 77% for gas. This achieves about 65% of the emissions reductions that a leasing ban would and raises $2 b/year in revenue above BAU, compared to the $5 b/year loss in revenues under a ban.

4. Discussion

Looking across the multiple cases – the three principles for determining the surcharge, the low and high demand elasticities, and whether there is a common carbon fee, a common royalty surcharge, or a different carbon fee for oil and gas – suggests three main conclusions.

First, all cases imply substantial climate royalty surcharges, typically in the 20% to 50% range. These surcharges are in addition to the current royalty rate of 12.5% (18.75% offshore). The current royalty rates, which for onshore oil and gas and surface-mined coal date to the MLA of 1920, neither take climate costs into account nor do they maximize revenue to the taxpayer. It is worth noting that any of the calculations here could have yielded a corner solution in which an increase in the royalty rate decreased royalty revenues, but that is not the case. Thus, all the royalty surcharges considered have both a traditional taxpayer return justification and a climate externality justification.

Second, for surcharges based on revenue or welfare maximization, both the revenue gains and emissions reductions are substantial compared to the no-policy BAU scenario. For example, for a common royalty surcharge, the revenue-maximizing surcharge of 36% reduces emissions by more than 40% of what would be achieved by a leasing ban, while increasing annual average revenues by $5.1B, compared to BAU.

Third, although the revenue-maximizing royalty surcharges and projected revenues with a surcharge do not depend significantly on the elasticity of demand, projected emissions reductions do. For the revenue-maximizing common surcharge of 36%, we estimate emissions reductions range from 34 to 58 MMTCO_2e/year. As a point of comparison, these round to one percent of US CO_2 emissions in 2019.

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Table 1. Bulk fuel prices and carbon fees in fuel price units

	Oil ($/barrel)	Natural gas ($/thousand cubic feet)	Coal ($/short ton)
2019 wholesale price	$57	$2.56	$12.5
12.5% royalty rate	$7.13	$0.32	$1.56
18.75% royalty rate	$10.69	$0.48	$2.34
$25 carbon fee	$10.75	$1.65	$42.41
$50 carbon fee	$21.50	$3.30	$84.42
$75 carbon fee	$32.25	$4.95	$127.23

Notes: Oil price is West Texas Intermediate spot price; natural gas is Henry Hub spot price; and coal is 8800 Btu/lb Powder River Basin subbituminous spot price. Prices are 2019 averages from the Energy Information Administration. Royalty rates are 12.5% for surface-mined coal and for onshore oil and gas and are 18.75% for deepwater offshore oil and gas. These rates are converted to native price units using the 2019 price in the first line and the carbon intensities for the relevant fossil fuel.

Table 2. Comparison of conventional policies to revenue-maximizing and welfare-maximizing charges

	Effective Carbon Fee ($/ton CO_2e)		**Effective Climate Royalty Surcharge (%)**		**CO_2e reduced**		**Royalties ($B/year)**
	Oil	Gas	Oil	Gas	million tons/year	% of ban	
(a) Conventional Policy							
BAU	$0		0%		0	0%	$9.2
18.75% Onshore Royalty Rate	$0		6.25%, onshore only		4	5%	$10.0
Leasing ban	$0		0%		80	100%	$4.0
(b) Common Carbon Fees ($/ton CO_2e)							
Revenue-maximizing	$20		15%	52%	29	36%	$13.2
Welfare-maximizing: $50 SCC	$14		10%	36%	18	23%	$12.6
Welfare-maximizing: $125 SCC	$34		26%	89%	60	74%	$9.4
CO_2e reduced: 80% of ban	$41		31%	106%	65	80%	$8.9
(c) Common Royalty Surcharge (% of Revenues)							
Revenue-maximizing	$48	$14	36%		34	42%	$14.3
Welfare-maximizing: $50 SCC	$25	$7	19%		18	22%	$13.2
Welfare-maximizing: $125 SCC	$60	$17	45%		42	52%	$14.0
CO_2e reduced: 80% of ban	$91	$27	69%		65	80%	$7.8
(d) Separate Carbon Fees for Oil and Gas ($/ton CO_2e)							
Revenue-maximizing	$40	$5	30%	13%	31	39%	$14.5
Welfare-maximizing: $50 SCC	$20	$15	15%	39%	24	29%	$13.4
Welfare-maximizing: $125 SCC	$40	$30	30%	77%	55	65%	$11.1

Notes: Emissions reductions based on base case elasticities. Entries for panel d are computed using the grid of separate gas and oil climate royalty surcharges in Table 3.

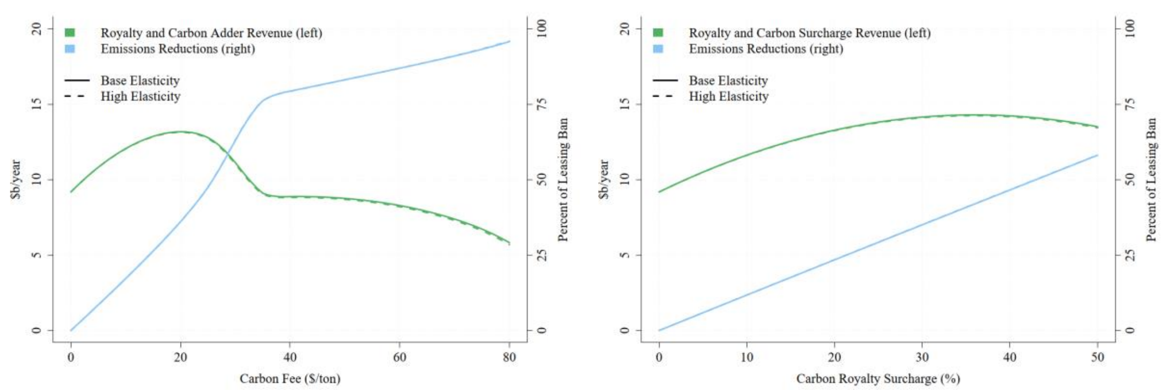
Table 3. Effect of distinct oil and gas carbon fees on total revenues (in $b/year top panel) and emissions (in MMTCO₂e/year, bottom panel), relative to BAU, base case elasticities

Oil carbon fee ($/ton)	Gas carbon fee ($/ton): $0	$5	$10	$15	$20	$25	$30	$35	$40	$45	$50
$0	$0.0	$0.6	$1.1	$1.4	$1.4	$1.1	$0.0	-$1.4	-$1.4	-$1.2	-$1.0
$10	$2.1	$2.6	$2.9	$3.0	$2.9	$2.4	$1.0	-$0.7	-$0.8	-$0.6	-$0.4
$20	$3.6	$4.0	$4.2	**$4.2**	$4.0	$3.3	$1.6	-$0.3	-$0.4	-$0.2	$0.0
$30	$4.7	$4.9	$5.0	$4.9	$4.6	$3.8	$2.0	-$0.1	-$0.2	-$0.1	$0.1
$40	$5.1	**$5.3**	$5.3	$5.1	$4.7	$3.8	**$1.9**	-$0.1	-$0.3	-$0.2	-$0.1
$50	$5.0	$5.0	$5.0	$4.8	$4.3	$3.4	$1.6	-$0.5	-$0.6	-$0.5	-$0.4
$60	$4.1	$4.2	$4.1	$3.9	$3.4	$2.6	$0.8	-$1.1	-$1.2	-$1.1	-$1.1
$70	$2.4	$2.4	$2.4	$2.1	$1.7	$1.0	-$0.5	-$2.0	-$2.1	-$2.1	-$2.0
$80	-$0.8	-$0.7	-$0.8	-$0.9	-$1.2	-$1.6	-$2.5	-$3.5	-$3.6	-$3.6	-$3.5
$90	-$4.0	-$4.0	-$4.0	-$4.1	-$4.1	-$4.3	-$4.6	-$4.8	-$4.9	-$4.9	-$4.9

Oil carbon fee ($/ton)	Gas carbon fee ($/ton): $0	$5	$10	$15	$20	$25	$30	$35	$40	$45	$50
$0	0	-3	-7	-12	-17	-25	-38	-50	-52	-52	-52
$10	-7	-10	-14	-18	-23	-30	-42	-53	-55	-55	-55
$20	-14	-17	-20	**-24**	-29	-36	-46	-57	-58	-58	-58
$30	-21	-24	-27	-31	-35	-41	-51	-60	-61	-61	-61
$40	-29	**-31**	-34	-37	-41	-46	**-55**	-63	-64	-64	-64
$50	-36	-38	-41	-44	-47	-52	-59	-66	-67	-67	-67
$60	-44	-46	-48	-51	-54	-57	-64	-69	-70	-70	-70
$70	-53	-55	-56	-58	-61	-64	-68	-73	-73	-73	-73
$80	-64	-65	-67	-68	-69	-71	-74	-77	-77	-77	-77
$90	-76	-76	-76	-77	-77	-78	-79	-80	-80	-80	-80

Note: Revenue-maximizing and welfare-maximizing cells under $50 and $125/ton SCCs are in bold. See Table 2.

Figure 1. 2020-2050 average royalty and carbon revenues (left axis) and emissions reduction relative to those achieved by a leasing ban (right axis) under a common per-ton carbon fee (left panel) or common percent surcharge (right panel)



Note: Annual average emissions reductions under a leasing ban are estimated to be 80 MMTCO₂e/year in the low-elasticity base case and 139 MMTCO₂e/year in the high-elasticity case.

Figure 2. Time path of total royalty revenues for alternative carbon fees or surcharges (billions of 2020 dollars)