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How Clean is “Refined Coal”? An Empirical Assessment of a Billion-Dollar Tax Credit

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Abstract

The US tax code provides nearly \$1 billion annually in tax credits to subsidize the use of “refined” coal, which is supposed to reduce emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury (Hg). Such coal accounts for a rising share of coal consumption from the power sector, reaching 20 percent in 2017. To be eligible for the tax credit (currently set at \$7 per ton, which is about 10–15 percent of the price of eastern coal and about 35 percent of the price of lignite), refiners must demonstrate that compared to standard coal, refined coal emits 20 percent less NO_x and 40 percent less SO_2 or Hg per unit of thermal energy. Firms typically demonstrate eligibility through a laboratory test, which can diverge from actual operational conditions. We use boiler-level data on power plant emissions in a panel regression framework to estimate whether burning refined coal actually achieves the emission reductions required for eligibility. Our estimates suggest that plants do not achieve the purported emissions reduction targets in practice, implying a misuse of billions of dollars in taxpayer funds. A cost–benefit analysis backs up the inefficiency of this legislation as applied. Because the tax credit is up for reauthorization in 2021, our work has immediate policy relevance.

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1. Introduction

A growing group of investors and electric utilities are refining and using coal that has been “refined” prior to burning to supposedly emit less nitrogen oxides (NO_x), sulfur dioxide (SO₂), and mercury (Hg). This “refined” coal—if it meets certain restrictions and targeted reductions in these pollutants—qualifies for a tax credit of \$7 per ton of coal. This subsidy is not small. In 2017 an estimated \$1 billion was paid out of the US Treasury, with similar sums being paid out in prior years since the credit was passed into law. The beneficiaries often include electric utilities, even though they don’t own the refined coal plants, as well as investors in these plants that range from members of the pharmaceutical industry to financial services. According to Reuters, one firm alone has claimed a total of \$850 million from this tax credit over the past decade (McLaughlin 2019).

Such sums might be socially valuable if the refined coal process actually led to the required reductions in these pollutants. But this analysis finds that in practice reductions are often much smaller than the requirements in the tax law.¹ We separately estimate the reductions in emission rates of NO_x, SO₂, and Hg attributable to refined coal. The tax law requires 20 percent reductions in NO_x emissions rates (i.e., NO_x emitted per unit of thermal energy burned) and 40 percent reductions in SO₂ or Hg emissions rates, which are typically verified through laboratory tests unrelated to actual plant operations. By contrast, we estimate that in practice plants achieve negligible reductions in SO₂ emissions rates, and the reductions in NO_x and Hg rates amount to about half (or less) of the reductions required. We find no evidence that any particular plant is achieving the reduction targets required by the tax statute—and significant evidence that on average they are not.

This suggests that the subsidy, which comes up for an extension in 2021, is economically inefficient and should be changed or eliminated. Indeed, our cost-benefit analysis concludes that the benefits of these small reductions do not justify their costs. The credit could be improved by basing eligibility on actual operational data (as opposed to lab tests), so that the credits are only granted to plants that can prove that they are actually achieving, in practice, the reductions required by law.

The next section provides background on the refined coal process, including the laboratory tests that frequently establish its environmental performance, the legislation that created the subsidy, and how the subsidy is distributed. After that we present anecdotal information about the actual emissions reductions provided by using refined coal in power plants—one set provided by a series of articles appearing in Reuters (McLaughlin 2018abc) and another set provided by analyzing continuous emission monitoring system (CEMS) data and supplementary abatement technology data for the four power plants that switched to refined coal at a known date. Then we present a set of regression analyses covering nearly all coal-burning power plants in the United States—those using refined coal and those not—to examine whether the requisite NO_x, SO₂ and Hg reductions are actually happening, accounting for abatement technology.

2. Background

2.1. The Process

Coal from a mine on its way to be burned by an electric utility will be redirected (usually on the utility's property) to a facility that may dry the coal (if it is lignite) and spray it with halogens (often calcium bromide) and cement kiln dust (CKD). The resulting chemically treated coal is known as “refined” coal. All standard types of coal (bituminous, subbituminous and lignite) can be refined. The calcium bromide oxidizes elemental Hg in the coal during combustion to an ionic form that can be trapped by various pollutant control devices downstream of the boiler emissions. Together these substances also are claimed to reduce NO_x and SO₂ emissions when the coal is burned, although the engineering literature focuses on Hg removal (see, e.g., Young et al. 2016).

The process is not without its problems. For a time, Duke Energy was a user of refined coal but found it unsatisfactory on several fronts. First, changes in the use of boilers (in particular burning fuel at higher temperatures) and in catalyst characteristics can make the refining process ineffective in reducing NO_x. Second, the alternative of operating at a lower temperature to reduce NO_x formation can lead to corrosion and soot buildup that causes boiler damage. Third, unreacted calcium bromide can escape in a plant's wastewater and ultimately form carcinogenic substances in drinking water. Researchers examining surface drinking water quality near a Duke plant with a refined coal facility reported significant bromide concentrations in water bodies that subsequently dropped 75 percent when the process stopped (Reuters 2018a). This is not an isolated incident. Good and VanBriesen (2019) show that bromines used in the coal refining process increase the vulnerability of drinking water supplies to the formation of toxic disinfection byproducts across the United States.

Refined coal facilities are cheap to build at scale, somewhere between \$4–6 million for conveyer belts, sprayers, storage facilities for the CKD and calcium bromide, plus control devices (such as baghouses and dust collectors) to ensure particulates from the process itself and the CKD storage units are captured. Levels of incremental Hg removal varied with the downstream pollution control units in place from 30 percent (raising SCR and CS-ESP removals of 60–90 percent) to 65 percent (raising SCR/SDA/FF removals of 20 percent to 85 percent).²

2.2. The Legislation

The first appearance of a subsidy (tax credit) for refined coal was in the American Jobs Act of 2004. This legislation had required emissions reductions for NO_x and either SO₂ or Hg. It also required that the refining process itself boost the coal's

market value by at least 50 percent, presumably by reducing the need for installing abatement equipment for NO_x, SO₂, or Hg (although there were no Hg control requirements at that time). This was a difficult hurdle to overcome because it would require refiners to convince utilities to agree to pay at least 50 percent markups for their coal. For years, take-up of the tax credit was minimal.

Four years later, this market value requirement was eliminated as part of the energy provisions in the Emergency Economic Stabilization Act of 2008—a law better known as the Troubled Asset Relief Program (TARP). Along with that change, the required pollution reductions on either Hg or SO₂ were doubled from 20–40 percent, making it harder for the coal to qualify for the subsidy (but easier to qualify with the market value test dropped). NO_x reductions were required to be at least 20 percent compared to standard feedstock coal of the same type and being burned under the same conditions. The rules subsequently released by the IRS in 2010 gave the producers of refined coal several ways to certify that their coal met these targets. They could use CEMS data or they could use laboratory testing. Most evidently opted for the latter (Reuters 2018c), probably because a field experiment could be costly and it might be difficult to isolate the effect of the coal itself on emissions without using rigorous statistical methods, as we do below.

The tax law includes some temporal restrictions on the tax credit, primarily limiting the credit to the first 10 years of a facility’s operation. This effectively eliminates the credit for many firms in 2021, if not earlier. Therefore, in 2018 legislators in Congress from coal states submitted an “extender” for this legislation to give plants an additional 10 years of eligibility (S.2373; H.R. 5159³) and opened up the eligibility requirements for refining facilities built between 2017 and 2021. On May 6, 2019, Senators Hoeven (R-ND) and Cramer (R-ND) introduced similar legislation, S. 1327, in the Senate, meaning this research has immediate policy relevance.

2.3. The Gains

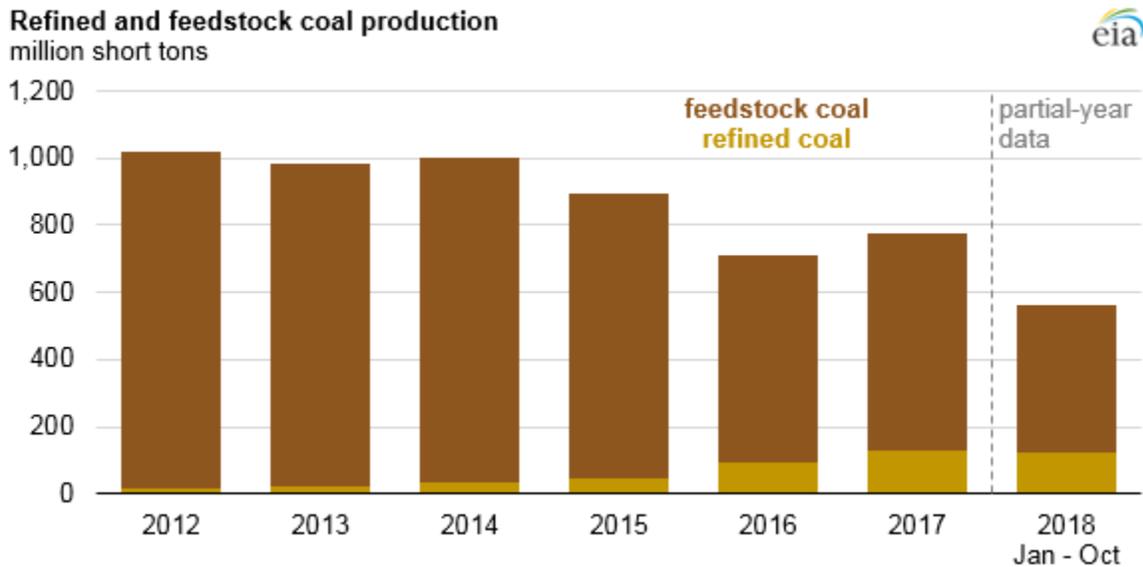
Because refined coal currently makes up about a fifth of the coal used in the power sector (i.e., 128 million tons in 2017), at a subsidy of \$7 per ton, the subsidy itself could amount to nearly \$1 billion per year. According to IRS data, six corporations claimed nearly \$300 million of credits in 2013, the last year for which the IRS published this data.⁴ This figure is likely much larger and growing faster today as the use of refined coal has risen dramatically since 2013, even as conventional coal use has declined. This can be seen in Figure 1, which plots coal use over time, revealing that refined coal has comprised a sharply rising share of US coal consumption.

Figure 2 shows that refined coals makes up a similar share of the three coal types used to generate electric power. According to data from the Energy Information Administration (EIA), 48 plants burned refined coal in 2018.⁵

Figure 3 shows the power plants that we analyze in this paper, including nearly all coal-burning power plants in the United States and covering over 90 percent of coal burned in the US power sector. Figure 3 shows plants that predominantly burned refined coal in 2016–2018 (depicted in red), alongside plants primarily burning regular coal (in gray), and plants that burned both refined coal and regular coal (in blue). Plants burning refined coal are generally concentrated in the Midwest, followed by the Mid-Atlantic and the South.

The owners and investors of the refining plants obviously benefit directly from the tax credit. In addition, the coal mining sector, the electric utilities using the refined coal, and electricity consumers may all benefit indirectly. The refined coal is typically bought from a plant at cost, refined, and sold back at a discount from \$0.75 to \$2.00 per ton (McLaughlin 2018b). And, depending on how the utility is regulated, such profits may be at least partly passed on to consumers. Coal demand may also increase from the program, benefiting the mining sector. Of course, any of these entities may also invest directly in building and financing refined coal plants, although the tax credit requires that the coal is sold “by the taxpayer to an unrelated person” (IRS 2010).

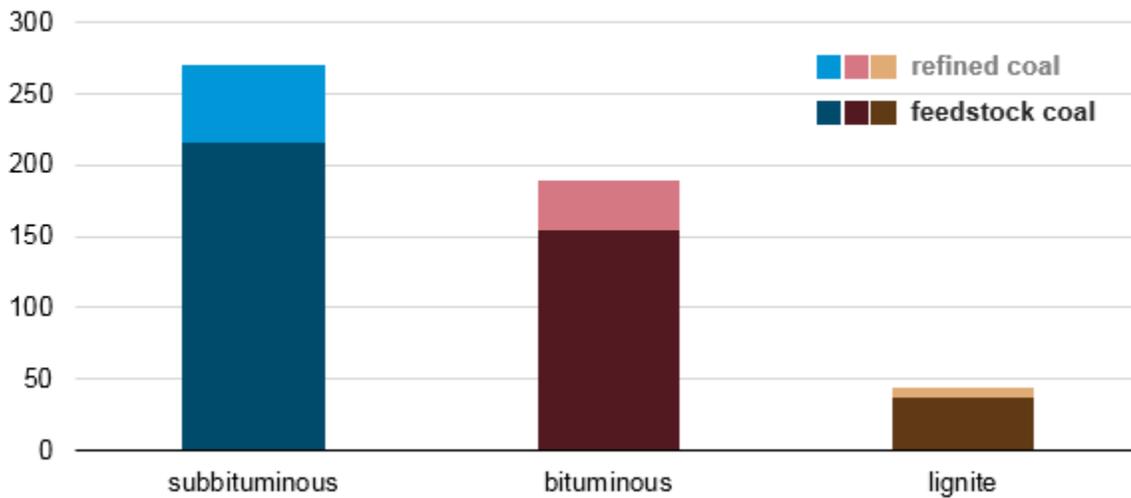
Figure 1. Coal Consumption over Time: Refined/Unrefined



Source: US EIA. 2019. Today in Energy: [US production and use of refined coal continues to increase](#). February 8.

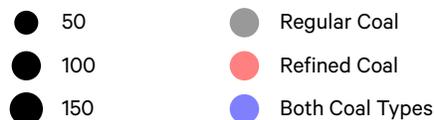
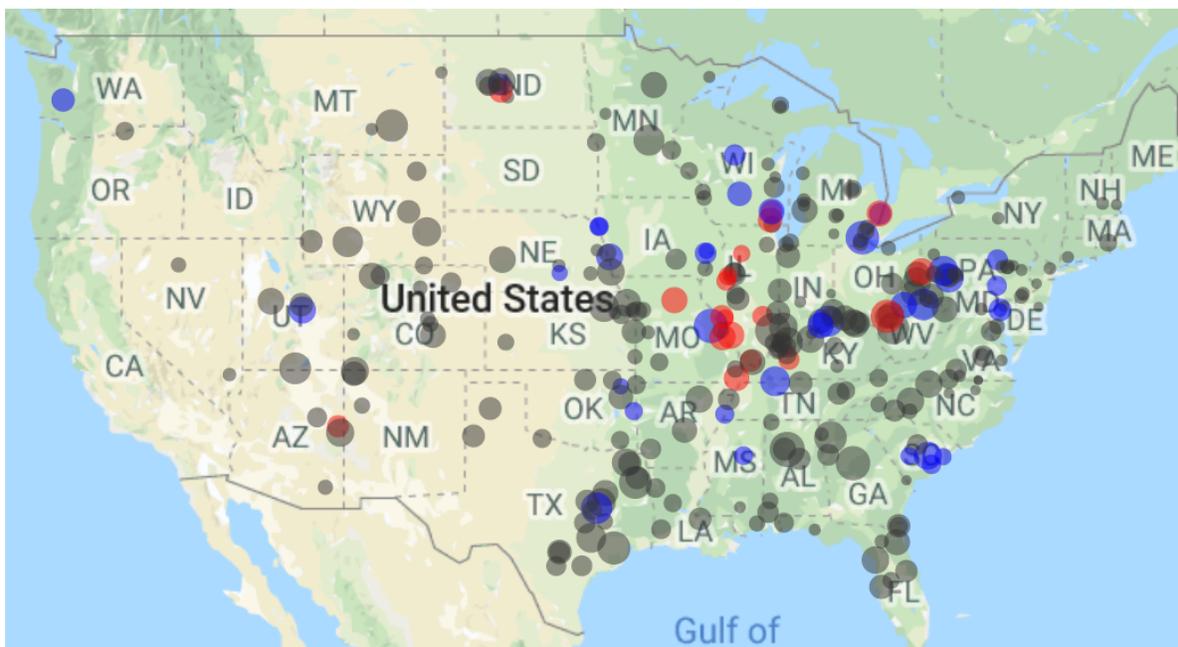
Figure 2. Coal Consumption by Coal Type

U.S. power sector coal consumption by type, Jan 2017 - Sep 2017
million short tons



Source: US EIA. 2017. Today in Energy: **Refined coal has made up nearly one-fifth of coal-fired power generation so far in 2017.** December 12.

Figure 3. Coal-Burning Plants in Sample by Primary Fuel(s) in 2016–2018.



3. Analysis

3.1. Approach

Rather than relying on laboratory testing to see if target reductions in NO_x and either SO₂ or Hg are occurring, we examine whether, other things equal, these pollutant targets are being met in practice.

We estimate reductions in emissions rates⁶ with and without refined coal using monthly variation in fuel consumption. Of course, many things could change over time with respect to a coal generation activity. First, there are changes in technology. Pollution controls could be added or be down for maintenance. Changes in regulations (such as the Mercury and Air Toxics Standards, MATS), affected many plants who then installed Hg controls, such as activated carbon injection (ACI) or Selective Catalytic Reduction (SCR), the latter of which can reduce both NO_x and also oxidize Hg to make it easier for flue gas desulfurization (FGD) technology to capture.⁷ In addition, many plants have installed low-NO_x burners. Operating conditions could also change. Coal quality itself could be changing, particularly heat content, but also sulfur and Hg content. In addition, the boilers could be run differently because of changes in load and dispatch patterns. Finally, trading programs were implemented for NO_x and SO₂, which would allow a plant to emit more NO_x (by shutting off or reducing the use of abatement equipment, or not installing it in the first place), and then buy NO_x reduction credits on the market to meet compliance targets.

We account for these factors by explicitly examining emission rates at the boiler level by fuel type, controlling for pollution control technology. This improves upon an anecdotal analysis performed by McLaughlin (2018a). That analysis assessed changes over eight years in plant-level total emissions (2017 versus 2009). In contrast, the emissions rates we estimate use boiler-level monthly data separately by fuel type; this approach directly corresponds to the IRS eligibility requirements for the tax credit.

3.2. Data

We use the CEMS data from the US Environmental Protection Agency (EPA), plus data on fuel consumption and pollution control equipment at each plant from EIA and EPA in our analysis. The CEMS data contains hourly, boiler-level emissions of NO_x, SO₂, and Hg.⁸ The EIA data contains monthly, boiler-level fuel consumption data for each fuel type. EIA only began distinguishing refined coal as a separate fuel type in 2016, so our sample window is 2016–2018.⁹ We also use EPA data on pollution control equipment installations. We cannot observe coal characteristics, but we note that most plants hold long-term contracts for coal, so its quality and type are unlikely to change at a plant over time.

3.3. Graphical Analysis

We perform two types of analyses: a limited plant-by-plant, before-and-after analysis and an econometric analysis on boilers accounting for more than 90 percent of coal burned in the US power sector. Figure 4–Figure 7 show the results of the first comparison. There are four panels in each figure representing the amount and type of coal (by type) burned over time, and the emissions rates over time of NO_x , SO_2 , and Hg. The shading around the line represents a 95 percent confidence band for the average emissions rate.

In Figure 4, the plant switched to refined coal in November 2016. Its NO_x rate actually rose by a statistically significant 10 percent. The SO_2 rate was approximately unchanged, and the Hg rose by nearly 60 percent (also statistically significant). We have determined that none of the confounding factors changed during this time period (e.g., no new technologies were installed); thus, this plant does not appear to have met the targeted reductions, suggesting that the refined coal it used should not qualify for a subsidy.

In Figure 5, the plant switched to refined coal in October 2016. Its NO_x rate was approximately unchanged (+1 percent) in the year and a half that followed. Emissions eventually fell starting in March 2018, when SCR (a NO_x control technology) was installed on the unit. This highlights the importance of controlling for pollution control technology in our statistical analysis. The SO_2 emissions rate rose by a statistically significant 21 percent¹⁰ and the Hg rate rose insignificantly (6 percent). This plant also did not appear to achieve the reductions required for the tax credit.

Figure 6 and Figure 7 show plants that are reducing their pollution of NO_x and Hg. However, the SO_2 rate is rising in Figure 7, and in both figures the estimated Hg reductions are statistically insignificant and also fall short of the targets.

Figure 4. Fuel Consumption and Emission Rates: Plant 1

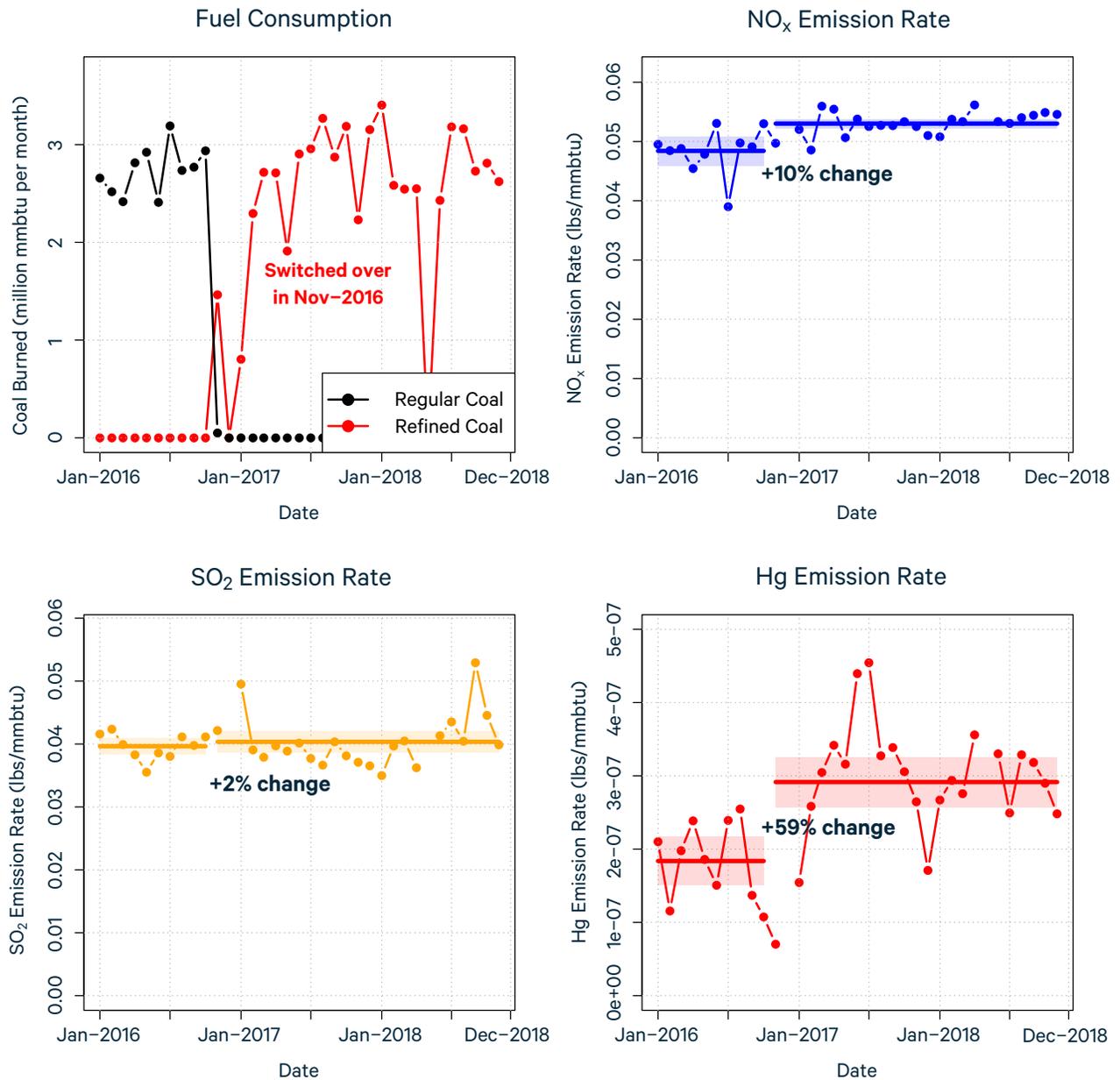
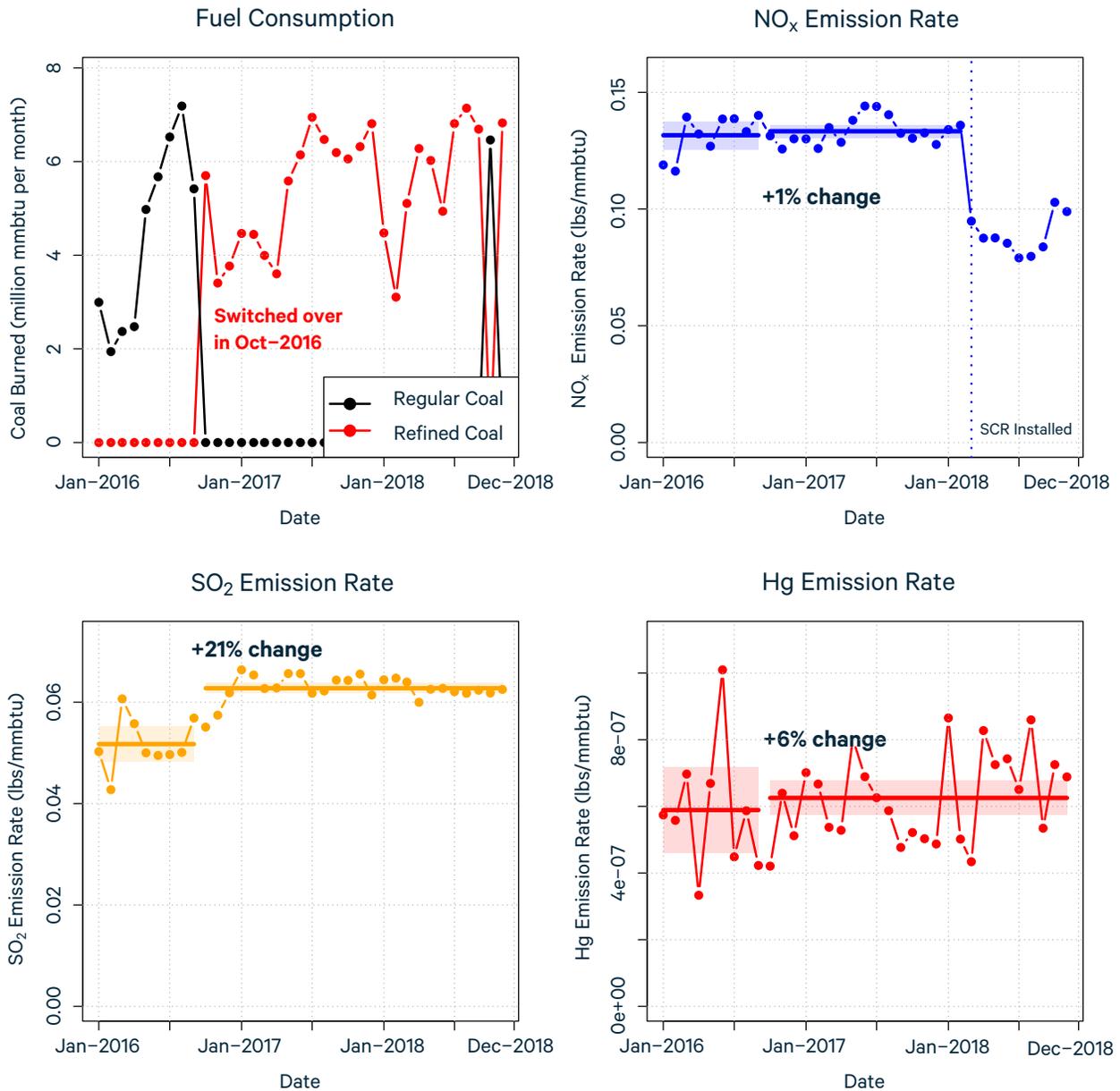


Figure 5. Fuel Consumption and Emission Rates: Plant 2



Note: The average bar for the post-refined-coal NO_x rates stops at February 2018 because SCR was installed in March 2018.

Figure 6. Fuel Consumption and Emission Rates: Plant 3

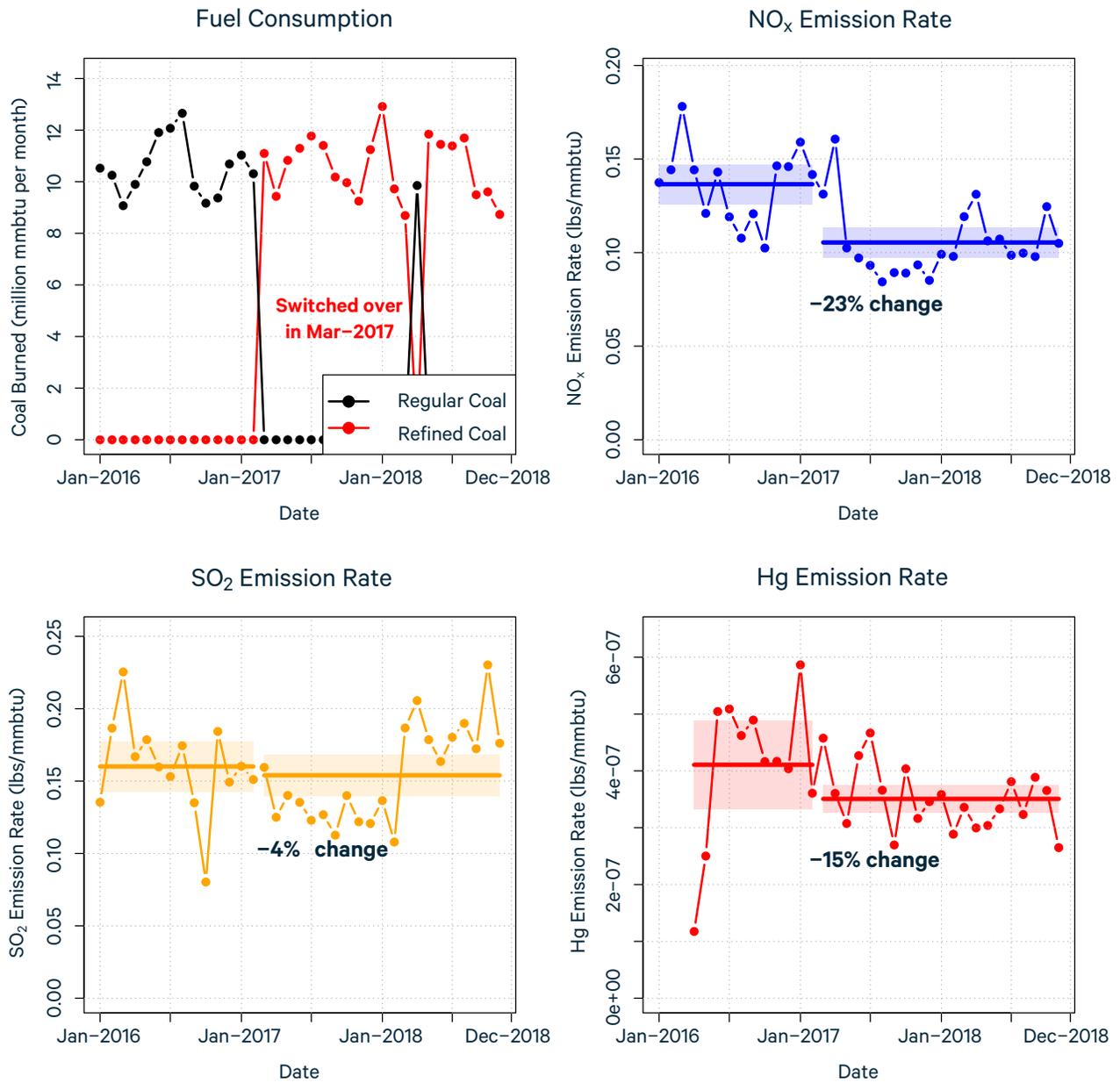
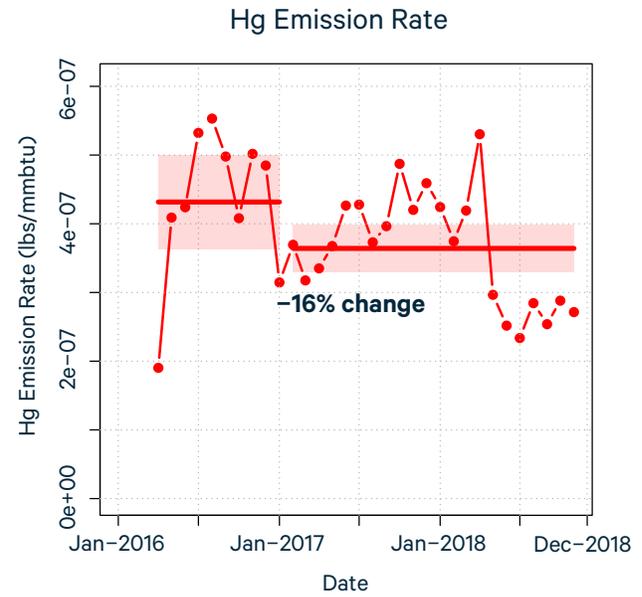
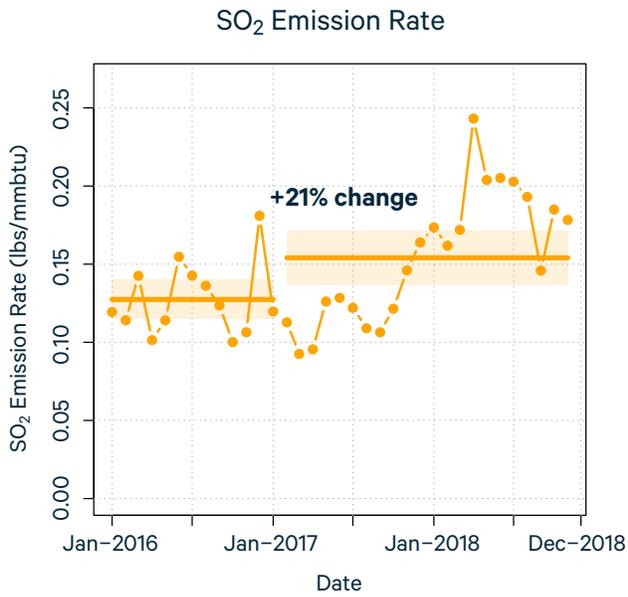
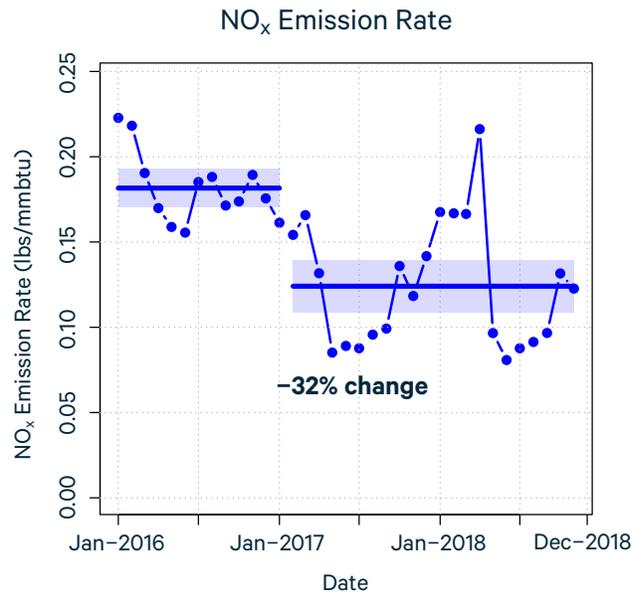
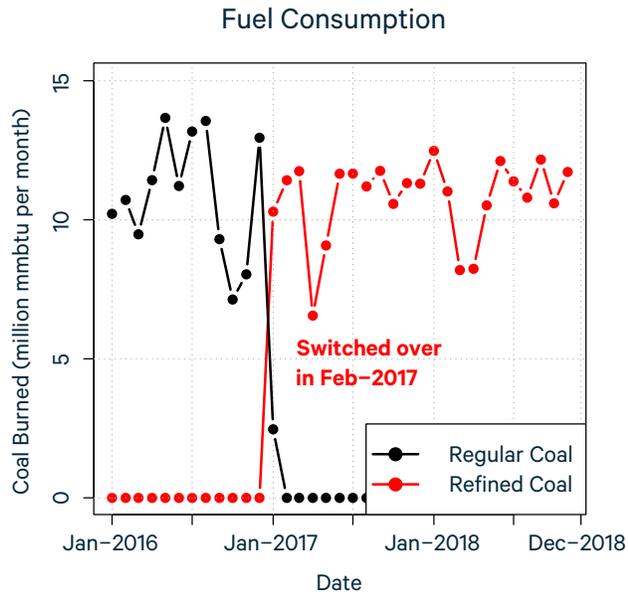


Figure 7. Fuel Consumption and Emission Rates: Plant 4



4. Quantitative Analysis

The above four graphs suggest that, for this very limited sample, refined coal is not achieving the emissions reductions required to be eligible for the tax credit. While this is anecdotal evidence, we can more rigorously and statistically estimate coal emissions rates using a dataset containing the vast majority of coal-burning power plants in the United States. We merge data from EPA and EIA, resulting in a final dataset of 639 boilers at 287 power plants across the country. This dataset accounts for more than 90 percent of coal burned in the US power sector.¹¹

4.1. Descriptive Statistics

Table 1 shows descriptive statistics of our compiled dataset. For the purposes of this table, we separate boilers into three groups: units burning predominantly regular unrefined coal (95 percent or more on a Btu basis), units burning predominantly refined coal (also 95 percent or more), and units burning both regular and refined coal (referred to as “dual coal” units).¹² We present these results to assess whether units that burn refined coal versus regular coal differ systematically. As such, we present means, standard errors, and p-values comparing differences in means.

There are some moderate differences between the plant types. Refined coal and regular coal plants are generally similar, except for some differences in pollution control technology. The difference in NO_x controls is statistically significant but practically small (99 percent versus 97 percent). The difference in SO₂ controls is substantial (59 percent versus 80 percent), again highlighting the importance of accounting for differences in control technology in our regression analysis. The average emission rates are slightly lower for NO_x and slightly higher for SO₂ and Hg, but the differences shown in this table are not statistically significant. In addition, the differences shown in this table do not themselves imply that refined coal itself produces higher or lower emissions, since the simple comparison of emissions rates does not account for differing plant characteristics such as pollution controls. Selection could play some role in determining which plants burn refined coal. We consider that in our econometric analysis.

“Dual coal” plants tend to be larger than regular coal plants. For example, dual coal units have an average capacity (measured as maximum observed gross load) of 600 MW on average, compared to 462 MW for regular coal plants. Similarly, they also have higher maximum heat input, maximum steam flow and coal firing rates. Some care must be taken when considering the average emissions rates of plants that burn both refined and regular coal. The average rate shown here is, in effect, a weighted average across all types of coal burned by the units (we disentangle these separate rates in our econometric analysis). Nonetheless, we do observe slightly lower NO_x and Hg rates (but not SO₂ rates) among dual coal units compared to regular coal units.

Table 1. Summary Statistics, by Unit Type

Variable	Mean			Standard Error			P-values		
	Regular Coal Units	Refined Coal Units	Dual Coal Units	Regular Coal Units	Refined Coal Units	Dual Coal	Regular vs. Refined	Regular vs. Dual	Refined vs. Dual
	w(1)	(2)	(3)	(4)	(5)	(6)	(1)-(2)	(1)-(3)	(2)-(3)
NO _x Emissions (lbs/month)	261,965	328,739	293,277	(10,840)	(46,542)	(22519)	0.162	0.21	0.493
NO _x Emission Rate (lbs/mmbtu)	0.178	0.161	0.145	(0.005)	(0.017)	(0.012)	0.348	0.009***	0.453
SO ₂ Emissions (lbs/month)	373,179	554,697	414,748	(24,266)	(96,637)	(49,333)	0.068*	0.45	0.197
SO ₂ Emission Rate (lbs/mmbtu)	0.240	0.263	0.215	(0.011)	(0.031)	(0.025)	0.488	0.372	0.235
Hg Emissions (lbs/month)	1.421	1.751	1.329	(0.104)	(0.314)	(0.145)	0.318	0.605	0.222
Hg Emission Rate (lbs/mmbtu)	0.642	0.729	0.538	(0.027)	(0.099)	(0.045)	0.402	0.047**	0.08*
Max Gross Load (MW)	462	530	600	(13.4)	(45.4)	(29.6)	0.149	<0.001***	0.195
Max Heat Input (mmbtu/hour)	5,027	5,662	5,985	(146)	(479)	(384)	0.205	0.02**	0.599
Share NO _x Controlled	0.97	0.99	0.94	(0.007)	(0.004)	(0.025)	0.018**	0.213	0.045**
Share SO ₂ Controlled	0.80	0.59	0.80	(0.018)	(0.073)	(0.045)	0.004***	0.976	0.012**
Share Hg Controlled	0.40	0.37	0.35	(0.023)	(0.071)	(0.054)	0.677	0.458	0.891
First Year in Service	1975.0	1972.2	1979.9	(0.6)	(1.4)	(1.8)	0.067*	0.01**	0.001***
Retirement Year	2027.6	2025.0	2036.9	(0.80)	(3.85)	(2.14)	0.514	<0.001***	0.007***
Max Steam Flow (1000lbs/hour)	3,024	3,500	3,779	(87.1)	(307.8)	(211.8)	0.137	0.001***	0.455
Coal Firing Rate (0.1 tons/hour)	208.1	236.4	236.6	(6.6)	(18.8)	(14.1)	0.154	0.067*	0.994
Boiler Efficiency at 100% Load	0.874	0.872	0.879	(0.001)	(0.003)	(0.003)	0.579	0.206	0.188
Boiler Efficiency at 50% Load	0.877	0.878	0.878	(0.001)	(0.004)	(0.004)	0.824	0.785	0.958
Observations (Unit-months)	14,459	1,470	2,552						
Number of Units	474	48	78						

Note: *p<0.1; **p<0.05; ***p<0.01. “Regular coal” units get 95% of their fuel from regular coal. “Refined coal” units are defined similarly. “Dual Coal” units are units that burned non-zero amounts of both refined and regular coal during the 2016–2018 sample window.

Finally, dual coal units are slightly younger units (average in-service year of 1980, as compared to 1972–1975 for the other plant types) with longer to go until expected retirement (2037 versus 2025–2028). Otherwise, dual coal units are broadly similar to regular coal units on pollution controls, total emissions, and unit efficiency.

4.2. Econometric Analysis

To assess whether burning refined coal results in lower emissions than regular coal, we use an econometric model that estimates emissions rates separately for NO_x , SO_2 , and Hg. We estimate emissions rates separately by fuel type (refined coal, unrefined coal, and other) and by an indicator for whether units had pollution controls installed. We do this by jointly estimating the following system of three equations:

$$\begin{aligned}
 NOx_{it} &= \alpha_i^{NOx} + c_{it}^{NOx} + \sum_j [\beta_{jc}^{NOx} F_{jit} * c_{it}^{NOx} + \beta_{ju}^{NOx} F_{jit} * (1 - c_{it}^{NOx})] + \varepsilon_{it}^{NOx} \\
 SO2_{it} &= \alpha_i^{SO2} + c_{it}^{SO2} + \sum_j [\beta_{jc}^{SO2} F_{jit} * c_{it}^{SO2} + \beta_{ju}^{SO2} F_{jit} * (1 - c_{it}^{SO2})] + \varepsilon_{it}^{SO2} \\
 Hg_{it} &= \alpha_i^{Hg} + c_{it}^{Hg} + \sum_j [\beta_{jc}^{Hg} F_{jit} * c_{it}^{Hg} + \beta_{ju}^{Hg} F_{jit} * (1 - c_{it}^{Hg})] + \varepsilon_{it}^{Hg}
 \end{aligned}$$

where NOx_{it} , $SO2_{it}$, and Hg_{it} are emissions (in lbs) by unit i in month t . The α_i terms are unit-level fixed effects (i.e., used to capture time-invariant differences across units not captured by other variables), and the c_{it} terms are indicators for whether unit i had emissions control equipment installed (for NO_x , SO_2 , or Hg) at time t . F_{jit} is unit i 's fuel consumption (in million British thermal units, or mmbtu) of fuel type $j \in \{Regular\ Coal, Refined\ Coal, Other\ Fuels\}$ in month t .¹³ Hence, the β_{jc}^p parameters measure the average marginal emissions rates (in lbs/mmbtu) for each fuel j and pollutant p , separately for when a unit has emissions control (β_{jc}^p) versus uncontrolled emissions (β_{ju}^p). With three fuel types and two potential control statuses, we estimate six emissions rates per pollutant. We then compare the estimated emissions rates of refined coal to those of regular coal to calculate emissions reductions.

We estimate the system of equations using seemingly unrelated regression (SUR), which permits statistically testing the joint hypothesis that refined coal qualifies for the subsidy (i.e., is achieving the statutorily required reductions of 20 percent on NO_x emissions and 40 percent on either SO_2 or Hg). We account for within-unit correlation in the errors by clustering standard errors at the unit level. We compute the covariance matrix using the cluster bootstrap methodology of Cameron and Miller (2015) with 1,000 draws.¹⁴

We estimate this set of equations twice. First, we estimate it using all coal boilers in our data, representing more than 90 percent of coal burned in the US power sector. In this case, the emissions estimated are identified by both within-unit variation in emissions and fuel consumption, as well as across-unit variation (e.g.,

comparing units burning regular coal to others burning refined coal). Because there is some concern that the latter source of identification could bias our results if there are other unobserved differences across units, we also estimate emissions rates only for the 78 boilers that burned both refined coal and regular coal in our sample window, which were previously discussed in Table 1. Since for these units we observe emissions by the same unit using different coal types, we can be confident that the results are not being confounded by time-invariant unobserved boiler characteristics, such as differing efficiencies. The other potential threat to identification is the installation of pollution control technology (e.g., see Figure 5), but we observe this and directly control for it.

The results are shown in Table 2. The first three columns show the estimates for all units, whereas the latter three show the results just for the dual coal units. The top panel presents the emissions rates. For example, in column 1 we find that, with pollution controls, the NO_x emissions rate from burning refined coal is 0.123 lbs/mmbtu, compared to 0.140 lbs/mmbtu for regular coal, a 12.5 percent reduction. Column 2 shows little difference for SO_2 rates (with controls: 0.155 lbs/mmbtu with refined coal versus 0.159 with regular coal). Column 3 shows (again for plants with controls) Hg rates of 0.576 $\mu\text{lbs/mmbtu}$ for refined coal compared to 0.759 for regular coal, a 24.1 percent reduction.

In the second panel of Table 2, we test whether these reductions are statistically significant. Namely, we test two hypotheses. First, we test whether the reduction is statistically significant from zero to determine whether refined coal is leading to any emission reductions at all. Second, we test whether the reduction is statistically different from the statutorily required levels (20 percent for NO_x , 40 percent for SO_2 and Hg). We conduct one-tailed hypothesis tests for both tests because we want to test whether the reductions are sufficiently large, either compared to 0 percent the legal targets of 20 percent and 40 percent.¹⁵

In most cases, we reject both null hypotheses. This means that refined coal appears to produce some statistically detectable emissions reductions, but they are not large enough to comply with the targets included in the statute.

With emissions controls, the 12.5 percent estimated reduction in the NO_x rate is significantly different than zero at the 5 percent level ($p=0.035$), but we can also reject that it achieves the 20 percent reduction target at the 10 percent confidence level ($p=0.077$). For Hg with controls, the result is even stronger: the 24.1 percent reduction is strongly significant ($p<0.001$), but it does not achieve the 40 percent target ($p=0.018$). We find little reduction in the SO_2 emissions rate with controls: a 2.3 percent reduction, not significantly different from zero, but significantly different from the 40 percent reduction target.

Turning to the results for the relatively few units without controls, the results are a bit different. Without NO_x controls, refined coal appears to create NO_x reductions of 60 percent, which exceeds the 20 percent target. However, so few plants lack NO_x controls (4 percent) that this finding has little practical implication. In fact, the data show that there is only one power plant without NO_x controls that burns refined coal, so these estimated reductions derive entirely from that single plant.¹⁶ For SO₂, refined coal appears to produce somewhat larger reductions of 10 percent; while this reduction is not significantly different from zero, we can reject that it achieves the 40 percent reduction target. For Hg, the impact of refined coal is a statistically insignificant 2.9 percent reduction. It is logical that refined coal only reduces Hg emissions when there are controls installed, since the chemical process by which refined coal is meant to work is by oxidizing the Hg to allow it to be better captured by various types of emissions control technologies.

The estimates using the full sample are generally similar to those using only the 78 units that burned both refined coal and regular coal in the 2016–2018 window. When using this restricted sample, the reductions are slightly larger for NO_x (both controlled and uncontrolled) and Hg (controlled only). Without controls, the reductions for Hg remain negligible. The SO₂ reductions with controls are very similar, but without controls the reduction disappears and we actually estimate that SO₂ emissions increase. All estimates retain their previous significance levels except for whether the NO_x reductions with controls achieve the 20 percent reduction target. We can no longer reject that the 20 percent reduction NO_x target is achieved ($p=0.25$). However, we can still reject that the 40 percent reduction targets for SO₂ and Hg are achieved ($p<0.001$ for SO₂ and $p=0.048$ for Hg). Since units must achieve reductions on not only NO_x but also SO₂ or Hg, we can therefore still reject that the program is, on average, achieving the statutorily required targets.

Table 2. Emissions Regressions

Sample: Dependent variable:	All Units			Units that Burned Both Refined and Unrefined Coal		
	NO _x (lbs) (1)	SO ₂ (lbs) (2)	Hg (lbs) (3)	NO _x (lbs) (4)	SO ₂ (lbs) (5)	Hg (lbs) (6)
Emissions Controlled						
Refined Coal Burned (mmbtu)	0.123*** (0.009)	0.155*** (0.013)	0.576*** (0.057)	0.110*** (0.012)	0.131*** (0.015)	0.549*** (0.065)
Unrefined Coal Burned (mmbtu)	0.140*** (0.005)	0.159*** (0.013)	0.759*** (0.052)	0.130*** (0.013)	0.135*** (0.015)	0.765*** (0.141)
Other Fuel Burned (mmbtu)	0.050 (0.036)	-0.039 (0.027)	0.031 (0.373)	0.012 (0.138)	-0.064 (0.045)	1.632 (2.584)
Emissions Uncontrolled						
Refined Coal Burned (mmbtu)	0.147*** (0.013)	0.511*** (0.044)	0.560*** (0.054)	0.146*** (0.016)	0.653*** (0.087)	0.406*** (0.047)
Unrefined Coal Burned (mmbtu)	0.367*** (0.053)	0.570*** (0.042)	0.577*** (0.044)	0.423*** (0.064)	0.525*** (0.044)	0.416*** (0.049)
Other Fuel Burned (mmbtu)	0.190 (0.391)	0.402*** (0.151)	0.186 (0.124)	0.983*** (0.247)	3.869* (2.037)	0.122 (0.112)
Pollution Control Indicator	Y	Y	Y	Y	Y	Y
Emissions Controlled						
Emission Rate Difference (%)	-12.5%	-2.3%	-24.1%	-15.5%	-2.7%	-28.2%
p-value for H0: No improvement	0.035	0.368	<0.001	0.020	0.283	0.001
p-value for H0: Required improvement	0.077	<0.001	0.018	0.250	<0.001	0.048
Emissions Uncontrolled						
Emission Rate Difference (%)	-59.9%	-10.4%	-2.9%	-65.4%	+24.4%	-2.4%
p-value for H0: No improvement	0.002	0.154	0.368	<0.001	0.998	0.377
p-value for H0: Required improvement	0.997	<0.001	<0.001	0.999	<0.001	<0.001
R-Squared (projected model)	0.465	0.533	0.319	0.412	0.605	0.346
Observations (unit-months)	19,408	19,408	14,825	2,552	2,552	2,127
Number of Units	639	639	507	78	78	73
Share of observations controlled	96.3%	78.2%	44.6%	94.0%	80.3%	38.7%

Note: *p<0.1; **p<0.05; ***p<0.01. Columns (4) through (6) only include units that burned both refined and unrefined coal during the sample window (2016-2018). The statutorily required reductions are 20% for NO_x and 40% for SO₂ and Hg.

We can test this more directly by considering the joint hypothesis that the NO_x targets and one of the SO₂ or Hg targets is being achieved. Since this is a non-standard statistical test, we assess it by calculating the share of the draws in the joint bootstrapped distribution achieving those targets.¹⁷ Since we have separately estimated reductions with and without emissions control equipment for NO_x, SO₂, and Hg, there are different possible combinations of reductions to test (e.g., with all three pollutants controlled, with NO_x and SO₂ controlled but Hg uncontrolled, etc.). For thoroughness, we test each possible combination, both for the regression results using all units and for the results using only dual coal units.

The results are shown in Table 3 and Table 4. Those tables show the share of bootstrapped parameter distributions under which the targeted reductions are achieved, alongside the point estimate for the emissions reductions for reference. In all cases, we can reject, at the 95 percent confidence level or better (and typically at the 99 percent level), that the targets are achieved. The primary reason for the variation across cases is whether the Hg targets are achieved. In the 1,000 bootstrap draws, the SO₂ target is never achieved, so compliance requires achieving 40 percent reductions in Hg. When Hg is controlled, only 1.8 percent and 4.8 percent (for the full and restricted samples, respectively) of the bootstrapped draws achieve the 40 percent reduction target. This alone places an upper bound on the share in compliance with the statute, since it also requires achieving the NO_x target.

The equipment scenario under which compliance with the statute (i.e., 4.8 percent in the bottom-left cells in Table 4) is most likely is (1) based on the regression results that use only the sample of dual coal units, (2) requires that HG control equipment is installed (38 percent of the sample), and (3) NO_x is uncontrolled (4 percent of the sample). Only three plants in the country have HG controls but not NO_x controls, and none burned refined coal in the sample window. This strongly suggests that the program is not achieving the targets required by the statute.

Table 3. P-values for Joint Tests of Meeting IRS Requirements, based on Bootstrapped Distribution of Parameters from Regression of All Units

SO₂ Controlled (Estimated Reduction: -2.3%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-24.1%	-2.9%
NO_x	Controlled	-12.5%	0.001	<0.001
	Uncontrolled	-59.9%	0.018	<0.001

SO₂ Uncontrolled (Estimated Reduction: -10.4%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-24.1%	-2.9%
NO_x	Controlled	-12.5%	0.001	<0.001
	Uncontrolled	-59.9%	0.018	<0.001

Table 4. P-values for Joint Tests of Meeting IRS Requirements, based on Bootstrapped Distribution of Parameters from Regression of Units Burning Both Refined and Unrefined Coal

SO₂ Controlled (Estimated Reduction: -2.7%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-28.2%	-2.4%
NO_x	Controlled	-15.5%	0.011	<0.001
	Uncontrolled	-65.4%	0.048	<0.001

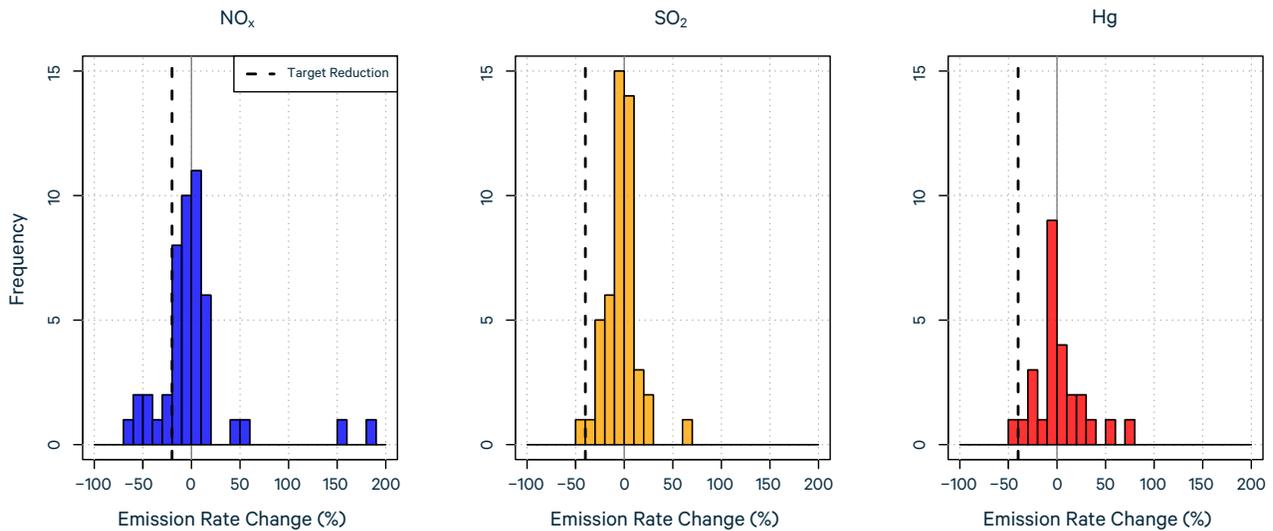
SO₂ Uncontrolled (Estimated Increase: +24.4%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-28.2%	-2.4%
NO_x	Controlled	-15.5%	0.011	<0.001
	Uncontrolled	-65.4%	0.048	<0.001

4.3. Unit Level Regressions

For further evidence, we estimate emissions reductions at the unit (boiler) level, where possible. Whereas the preceding results show average emissions rates, it is possible that these averages mask heterogeneous effects whereby some plants achieve the targeted reductions whereas others do not. To address this possibility, we re-estimate our model at the unit level where there is enough identifying variation to do so. This is possible for the majority of the “dual coal” units. It is not possible for all units because it requires observing a given unit both before and after switching from regular to refined coal (or vice versa), and under identical emissions control conditions. We have sufficient variation in the data to estimate potential reductions from refined coal for 47 units for NO_x , 48 units for SO_2 , and 26 units for Hg.¹⁸ Histograms of these reductions are shown in Figure 8 (negative changes indicate reductions, positive ones indicate increases). Less than a fifth of these units is estimated to achieve the required NO_x reductions. Only one unit achieved the reductions in SO_2 (but it did not achieve the Hg reductions), and another achieved the reductions in Hg (but not the SO_2 reductions), and neither of those units achieved the NO_x reductions. As a result, none of these units are estimated to achieve the reductions required by the tax statute. Quite a few estimates even suggest an increase in emissions from refined coal use. In summary, we find no evidence that any plant is achieving the required reductions.

Figure 8. Histograms of Estimated Emission Rate Reductions for Units with Sufficient Data



4.4. Reasons Why Plants Might Not Achieve Emissions Reductions

Why might plants not be achieving the 20 percent and 40 percent reductions in emissions rates that the law requires? While we do not know how policymakers chose these particular targets when devising the legislation, we can speculate as to potential reasons that plants might be falling short.

First, while the mechanism for the Hg reductions is well understood based on conversations with engineers (it oxidizes the Hg, making it easier to capture), it is not obvious why this would reduce NO_x or SO₂ emissions at all. This aligns well with our finding of negligible SO₂ reductions, but we do estimate modest NO_x reductions. The mechanism behind this reduction is not clear.

A second possibility is that refined coal does reduce emissions, but plants systematically dial back or even shut down other emissions control technologies. For example, plants can save money by reducing the amount of ammonia injected to a SCR. Based on conversations with industry experts and EPA, some plants have indeed reduced their use of pollution controls when the NO_x allowance caps became non-binding. If plants are indeed reducing the use of pollution control technology due to the refined coal tax credit, then the subsidy is creating perverse incentives. These effects would be correctly captured in our estimates, which considers the overall net effect of refined coal use.

4.5. Policy Evaluation and Cost–Benefit Analysis

While our econometric analysis strongly suggests that the subsidy to refined coal plants is failing to generate the requisite NO_x and SO₂ or Hg emissions reductions, it may still be the case that the legislation passes a cost–benefit test from either or both of two perspectives: (1) based on the actual pollution reductions, or (2) based on the larger pollution reduction targets in the legislation. Therefore, we estimate these benefits and compare them to the social costs of the subsidy, which we estimate to be about \$7 per ton (including private refining costs and the excess burden of taxation). Failure to pass based on both actual pollution reductions (1) and the larger reductions required by law (2) is evidence for repealing (not renewing) the legislation. Failure to pass based on actual reductions (1) but nonetheless passing test based on the larger required reductions (2) implies that society is better off with the legislation than not—as long as targeted emissions reductions are in fact met in the field. This implies that a change in the law is needed, to drop laboratory testing for demonstrating compliance and replace it with field testing.

Because we observe the subsidy and the plants using the refined coal, this cost–benefit analysis is retrospective (as opposed to the prospective cost–benefit analysis performed in a federal government Regulatory Impact Analysis [RIA]). We

compare the benefits in 2017 with the total costs, including the private refining costs and the excess burden of taxation (i.e., the economic inefficiency caused by the government raising funds to pay for the subsidy)

4.5.1. Benefits

The immediate impacts of using refined coal are the emissions reductions for the plants using this coal, which ultimately leads to health and environmental improvements. When these improvements are monetized, they are termed benefits.

To be specific about our benefits analysis, we discuss the potential benefit pathways and those we actually model. Pollutants from a power plant are emitted from a tall stack where they then disperse and transform in the air—in particular, the NO_x emissions convert to $\text{PM}_{2.5}$ and ozone under the appropriate conditions, and the SO_2 converts to $\text{PM}_{2.5}$. The unconverted NO_x and SO_2 , as well as the $\text{PM}_{2.5}$, ozone, and Hg emissions, all cause physical impacts, depending on the populations and sensitive environmental resources being affected. Typically, the largest monetary benefits from air pollution control are those to human health, particularly to reducing human mortality. $\text{PM}_{2.5}$ reductions have the largest marginal impacts on mortality risks of any of the affected pollutants. And the monetary values typically used in emissions control cost-benefit analysis (i.e., an RIA when performed by the federal government) are far larger for mortality risk reductions than for any other impact category. While a number of impact pathways are ignored in this analysis, as noted, we capture the main ones.

Our analysis makes use of the COBRA model,¹⁹ an EPA-approved benefits model at the county level, which incorporates source-receptor matrices, pollutant transformation functions, demographics, and a variety of concentration-health response functions. We focus on the adult mortality risk reductions from $\text{PM}_{2.5}$ reductions attributable reductions in NO_x and SO_2 emissions. We use the model to estimate the benefits in 2017 by calculating how emissions at plants burning refined coal would differ had they not achieved the reductions that we estimate. That is, we adjust actual 2017 emissions from refined coal plants according to the estimated reductions in Table 2 (columns 1–2).²⁰ We then calculate benefits as the difference in mortality at actual emissions levels and at the (higher) emissions levels without refined coal. As a sensitivity, we re-run this analysis using the unit-level estimated reductions where possible. Finally, we estimate the benefits that would be achieved if the legislative targets were met.

We emphasize that our estimates likely overstate the actual benefits attributable to the refined coal tax credit for several reasons. First, we assume that, absent the tax credit, the same amount of coal (in mmbtu) would be burned in absence of the refined coal tax credit, simply at a different emissions rate (lbs/mmbtu). In reality, the tax credit may have increased the amount of coal burned because it reduced the marginal cost of burning coal, leading them to operate more often. For example,

for a typical coal plant burning coal with a heat content of 20 mmbtu/ton at a heat rate of 10 mmbtu/MWh, a \$7 per ton tax credit effectively reduces after-tax operating costs by \$3.5/MWh.²¹ This can be a large cost reduction, for example, for plants burning cheap, low-quality coal such as lignite, which sells for \$20 per ton, on average.²² While these estimates do not account for the private refining costs, they are roughly indicative of the magnitude of the tax credit relative to fuel costs, which could increase the amount of coal burned.

The revenue from the tax credit may have an effect on the extensive margin as well, with the flow of revenues preventing the retirement of otherwise unprofitable plants. Both of these factors are ways in which the refined coal tax credit can increase total emissions by increasing the amount of coal burned, even if the coal has somewhat lower emissions per ton.

The second reason why our estimates may overstate the benefits of refined coal has to do with how NO_x and SO₂ are regulated. Both pollutants are covered to varying degrees by emissions trading (i.e., cap-and-trade) programs: the Acid Rain Program and Cross-State Air Pollution Rule. To the extent that refined coal reduces emissions at regulated plants, this frees up emissions permits that can be sold to another plant. Some caps have been binding in recent years (i.e., summertime seasonal NO_x), whereas others have not been binding. Any emission reductions covered by a binding cap would be offset one-for-one by emission increases at other covered plants. This implies that reductions attributable to refined coal at some plants may simply redistribute the location of emissions, rather than reducing emissions overall.

On the other hand, NO_x allowance prices have been very close to zero in recent years, except in the summer when seasonal allowances have been clearing at substantially positive prices. Further, SO₂ caps have generally been non-binding in recent years.²³ This suggests that the cap may not always be binding. Overall, this again suggests our estimates of the benefits of refined coal represent an upper bound of the true benefits. Another reason we may be overstating the impacts of the refined coal tax credit is other regulations. We assume that no firm would burn refined coal in absence of the tax credit, but some firms might continue to burn it to comply with other regulations, such as the MATS rule regulating Hg emissions. Hence, repealing the credit may have a smaller impact on refined coal use than we assume.

One factor goes in the other direction: we focus only on the PM2.5 adult mortality benefits from reduced NO_x and SO₂ emissions. While this captures approximately 90 percent of the benefits of reducing PM2.5 based on results in many RIAs, it does not consider the benefits from reduced ozone formation and Hg emissions (the estimated benefits of the latter being particularly small in the MATS rule RIA).²⁴

We report our results for several runs. For test (1) above, we compute the benefits from refined coal use using our estimated reductions for NO_x and SO₂ emissions relative to the actual emissions. For test (2) we compute the benefits from refined coal use under the assumption that all plants are meeting the legislative emission reduction targets for NO_x and SO₂, relative to the counterfactual of no refined coal use.

For the latter test, we are effectively assuming that firms comply using the SO₂ rather than the Hg emissions target. In contrast, the predominate reason for using refined control, judging from literature referenced in this paper, is to reduce Hg emissions. However, as noted above, the quantifiable HG effects on health and the monetary value of these effects are very small compared to the effects of reduced SO₂ emissions and their conversion to fine particles. Thus, our approach greatly overstates the quantifiable benefits of refined coal in this scenario. Accordingly, we also show the COBRA model results separated by NO_x and SO₂ emissions, so we can consider the benefits if only NO_x emissions are reduced by 20 percent. This would correspond to a scenario in which plants achieve eligibility using NO_x and Hg reductions, but the Hg reductions are valued at close to zero (as EPA has done in its MATS RIA).

4.5.2. Costs

There are two components of total (social) costs. The first is the private costs of the technology. Variable costs are low. We estimate²⁵ that the real economic costs of refining are about \$5 per ton of coal processed. Multiplying by the tons of refined coal processed and burned in 2017 suggests private costs of about \$600 million annually.²⁶

The second component of social costs is the excess burden of taxation. This represents the economic inefficiency caused by other taxes used to raise public funds to finance the subsidy. Parry (2002) suggests a typical excess burden of at least 30 percent, suggesting that a conservative estimate of the cost of excess burden is $\$7 \times 0.3 = \2.1 per ton.

The social cost is the private cost plus the excess burden, or $\$5 + 0.3 \times \7 , which is just about \$7 per ton. Multiplying by the total tons of coal refined in 2017 yields a social cost of about \$900 million annually.

4.5.3. Results

Figure 9 depicts the air quality benefits of using refined coal relative to conventional coal use, under three different assumptions about emissions reductions. The first bar shows the benefits assuming all units reduce emissions by the estimates shown in the first three columns of Table 2 (i.e., 12.5 percent NO_x when controlled, 2.3 percent SO₂ when controlled, etc.). We estimate emissions benefits of \$457 million

annually (2017\$). Since 122 million tons of refined coal were burned by the plants in our simulation in 2017, this corresponds to benefits of \$3.80 per ton. Most of this benefit comes from SO₂ reductions. If plants comply primarily by reducing NO_x and Hg, the benefits would be a much smaller \$129 million from NO_x, plus a negligible quantifiable benefit from Hg reductions.²⁷

The estimates are similar if we use plant-level emission reductions where possible (see Figure 8): \$589 million annually, or \$4.80 per ton. In both cases, the estimated benefits are below the social costs of burning refined coal, as well as below the subsidy value of \$7 per ton. In the final case, we estimate what the benefits would be if all plants were achieving the targets required by the tax statute (20 percent reduction in NO_x and 40 percent reduction in SO₂). If the targets were achieved, we find benefits of more than \$3.6 billion annually (\$30 per ton), which greatly exceeds the subsidy value. This suggests that the policy could be beneficial if the targets were actually being met and were incremental to reductions currently occurring from pollution control equipment. However, the vast majority (94 percent) of the benefits arise from SO₂ reductions, which our estimates suggest are not actually arising in practice (see Table 2). As for NO_x emissions, some plants may be shutting off their NO_x control equipment, offsetting any reductions attributable from refined coal.

Put differently, had NO_x and SO₂ emission rates actually fallen by 20 percent and 40 percent to qualify for the subsidy, benefits of more than \$3 billion annually would have been realized, reflecting the monetized value of 340 reduced premature deaths each year.

Figure 10 shows the geographic distribution of the benefits of improved air quality. The benefits are generally concentrated in and around large Midwestern cities such as Chicago, Detroit, Columbus, and Cleveland. Other cities further east also benefit from reduced concentrations (in particular, Pittsburgh, Buffalo, and Rochester), since they are affected by Midwestern emissions due to predominant winds that blow from west to east. Corresponding maps for the other two scenarios look qualitatively similar and are shown in the appendix.

Figure 11 shows the same benefits normalized by county-level population. This illustrates that the positive impacts are similar on a per-capita basis, and the clustering of benefits in cities is the natural result of a larger number of households exposed to lower concentrations in cities. The benefits for the median county are \$2.46 per capita, but a small number of counties are particularly impacted (primarily counties with multiple nearby plants burning refined coal), while a large number of distant counties experience minimal impacts.

Figure 9. Air Quality Benefits from SO₂ and NO_x, under Different Emissions Reductions Scenarios

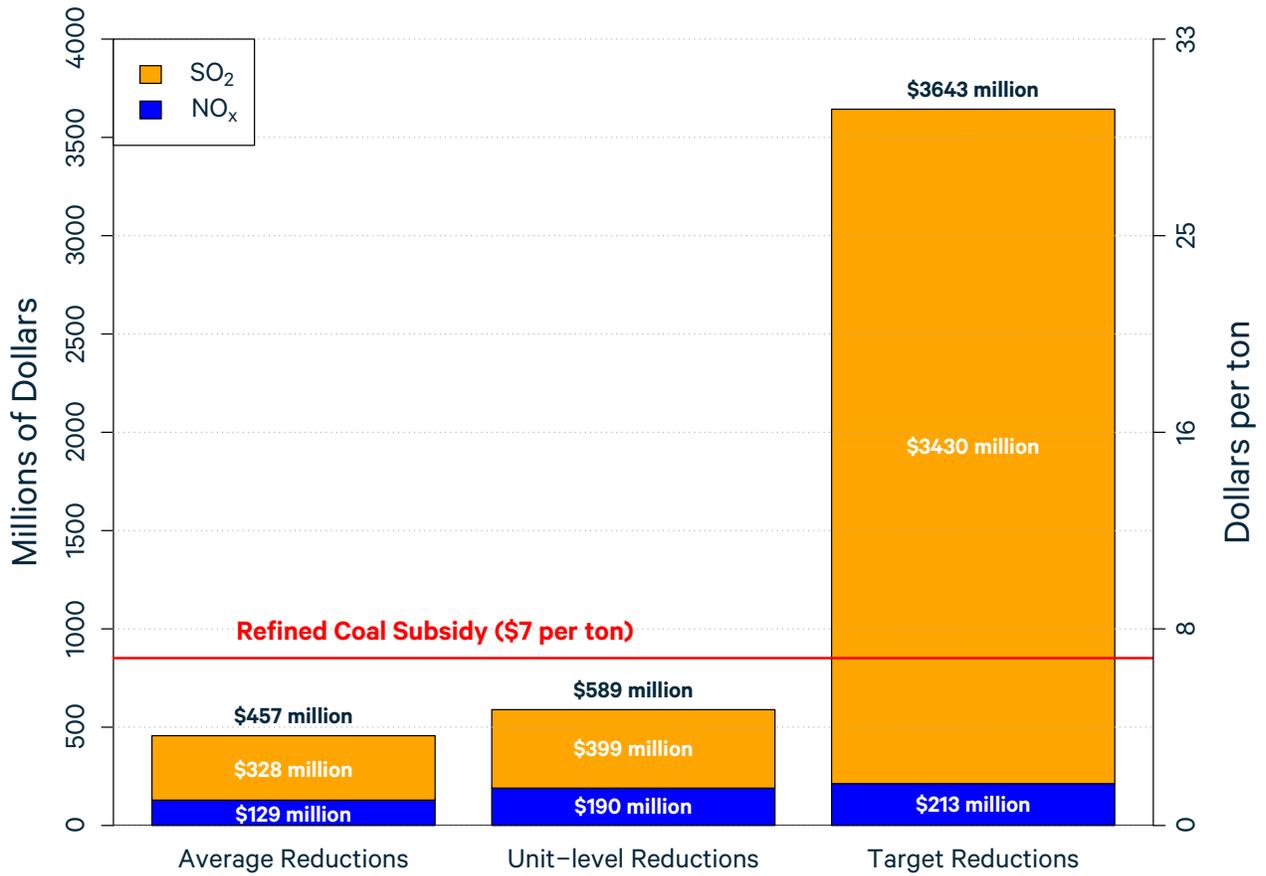


Figure 10. Distribution of Air Quality Benefits (millions of dollars) from SO₂ and NO_x, under the “Average Reductions” Scenario

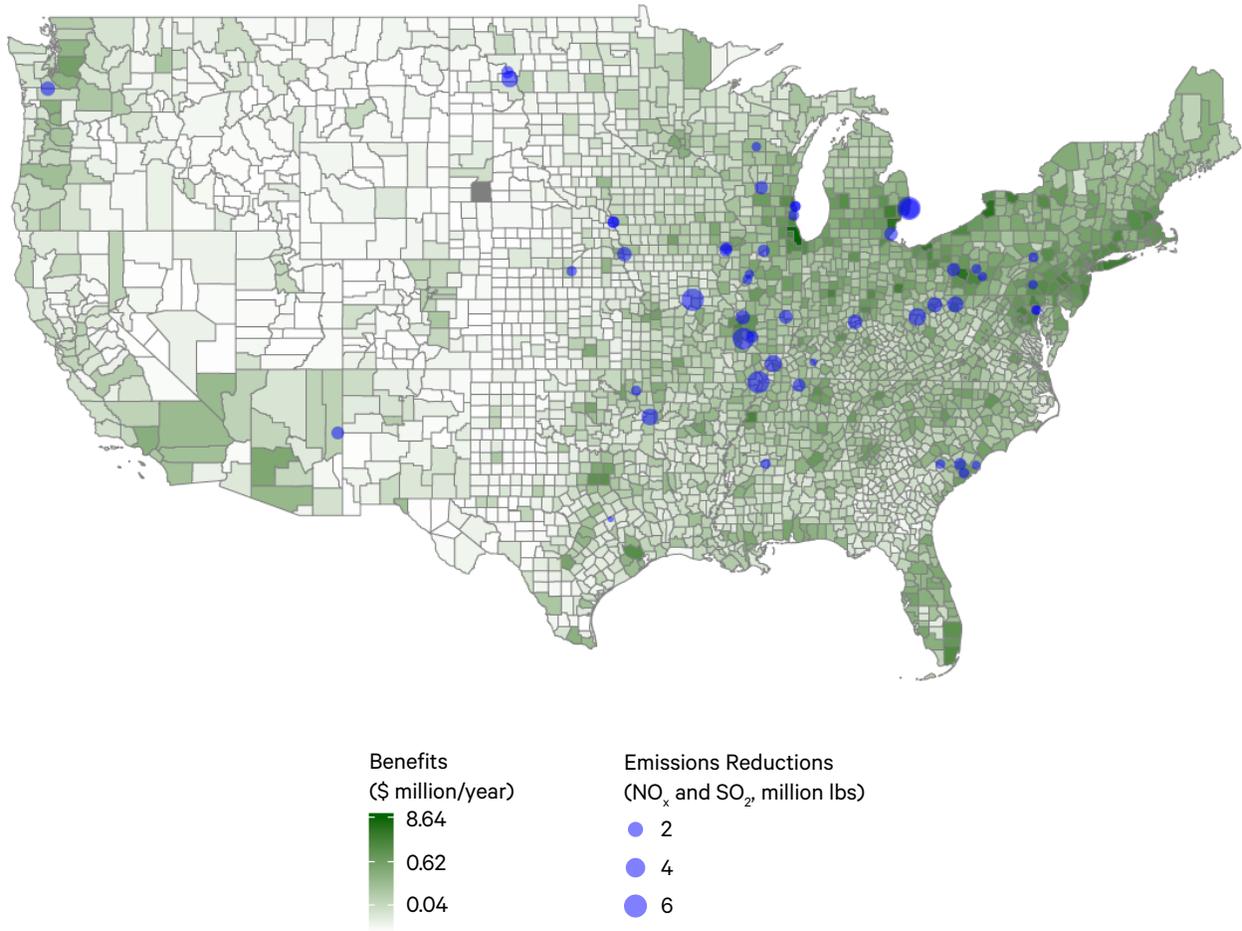
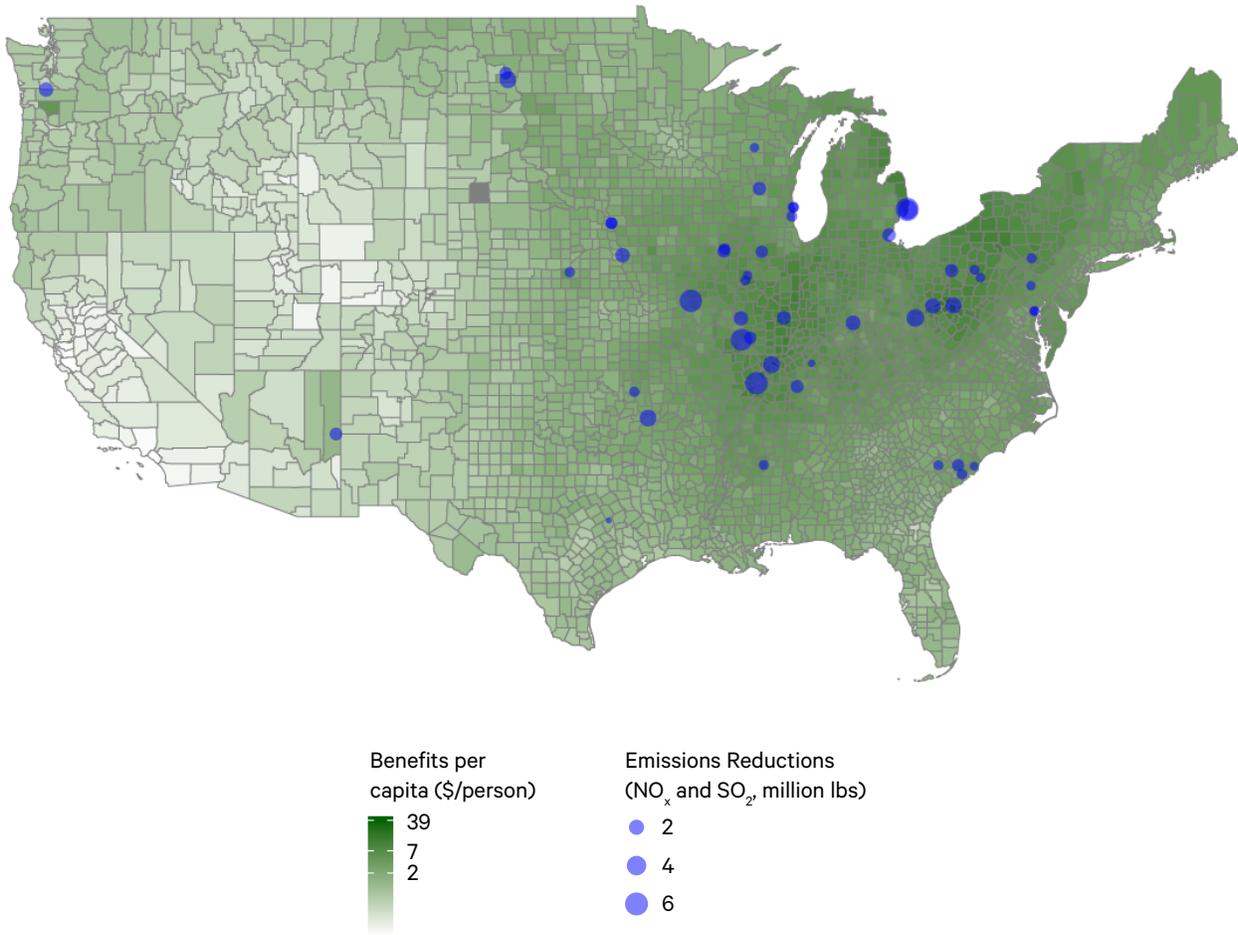


Figure 11. Distribution of Air Quality Benefits (dollars per capita) from SO₂ and NO_x, under the “Average Reductions” Scenario



5. Conclusion

We estimate emissions rates for refined and unrefined coal using a dataset covering more than 90 percent of coal in the US power sector. We find that in practice the reductions fall short of the targets required for legal eligibility for the federal refined coal tax credit. Reductions are often much smaller than the requirements in the tax law. While the tax law requires 20 percent reductions in NO_x emissions per mmbtu and 40 percent reductions in SO_2 or Hg emissions per mmbtu, these reductions are typically verified using lab tests, as opposed to actual operational outcomes. Using data on actual operations, we find that in practice plants achieve negligible reductions in SO_2 emissions, and the reductions in NO_x and Hg amount to about half (or less) of the reductions required. We find no evidence that any particular plant is achieving the reduction targets required by the tax statute, and significant evidence that on average they are not.

This suggests that the subsidy, which comes up for an extension in 2021, is economically inefficient and should be changed or eliminated. A cost-benefit analysis confirms that the benefits of these small reductions do not justify their costs. The credit could be improved by basing eligibility on actual operational data (as opposed to lab tests), so that the credits are only granted to plants that can prove that they are actually achieving, in practice, the reductions required by law.

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Appendix

Figure 12. Distribution of Air Quality Benefits (millions of dollars) from SO₂ and NO_x, under the “Unit-Level Reductions” Scenario

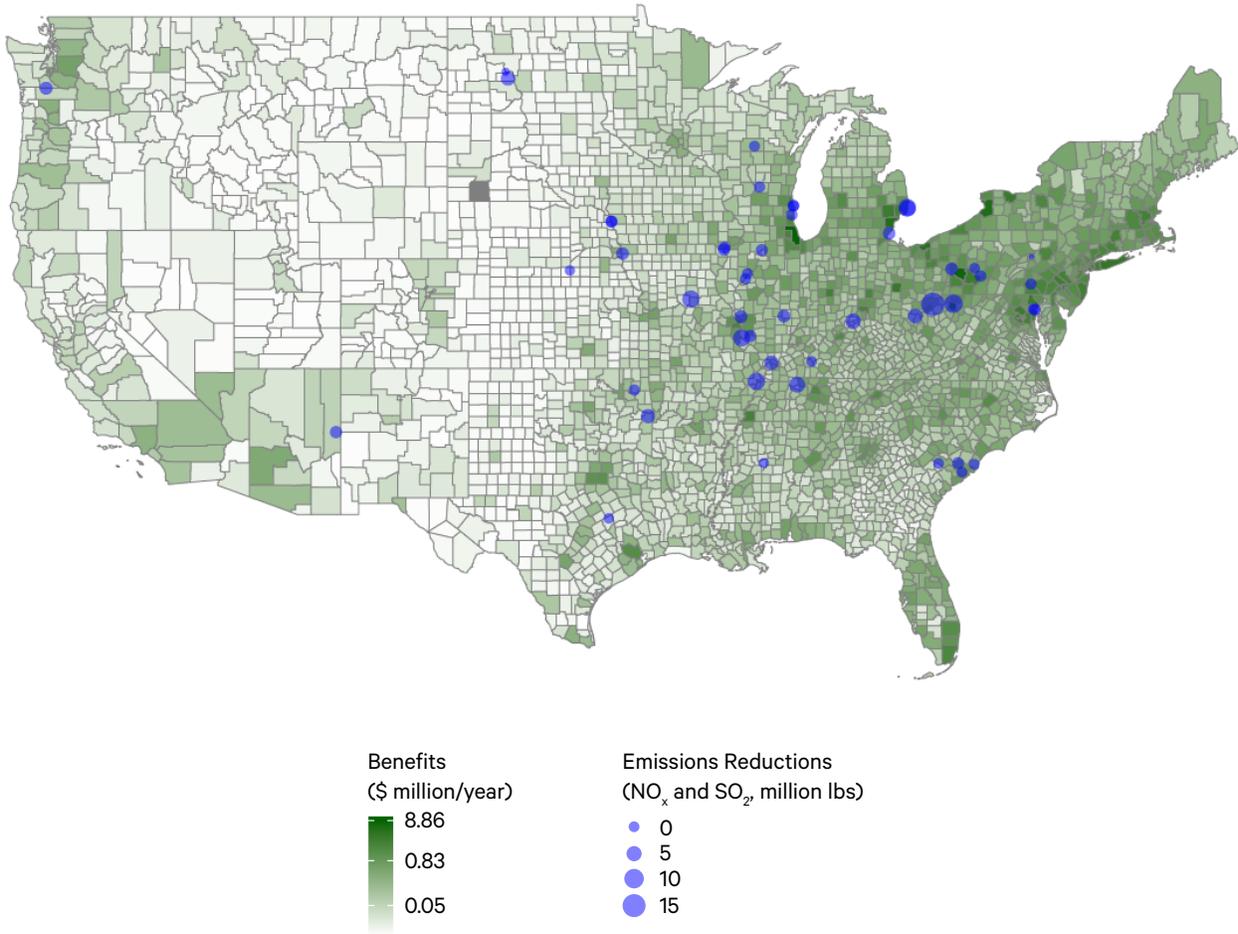


Figure 13. Distribution of Air Quality Benefits (dollars per capita) from SO₂ and NO_x under the “Unit-Level Reductions” Scenario

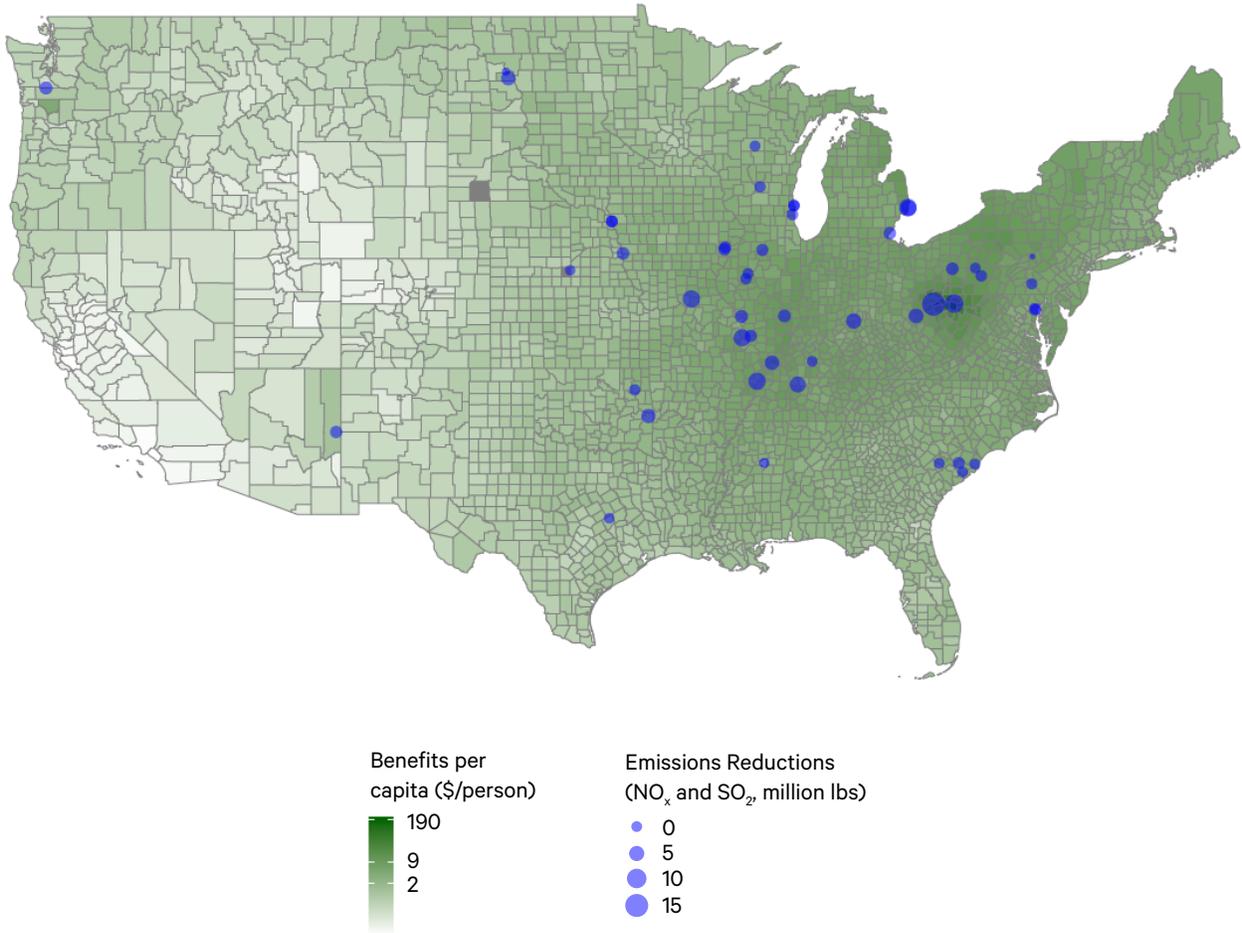


Figure 14. Distribution of Air Quality Benefits (millions of dollars) from SO₂ and NO_x, under the “Target Reductions” Scenario

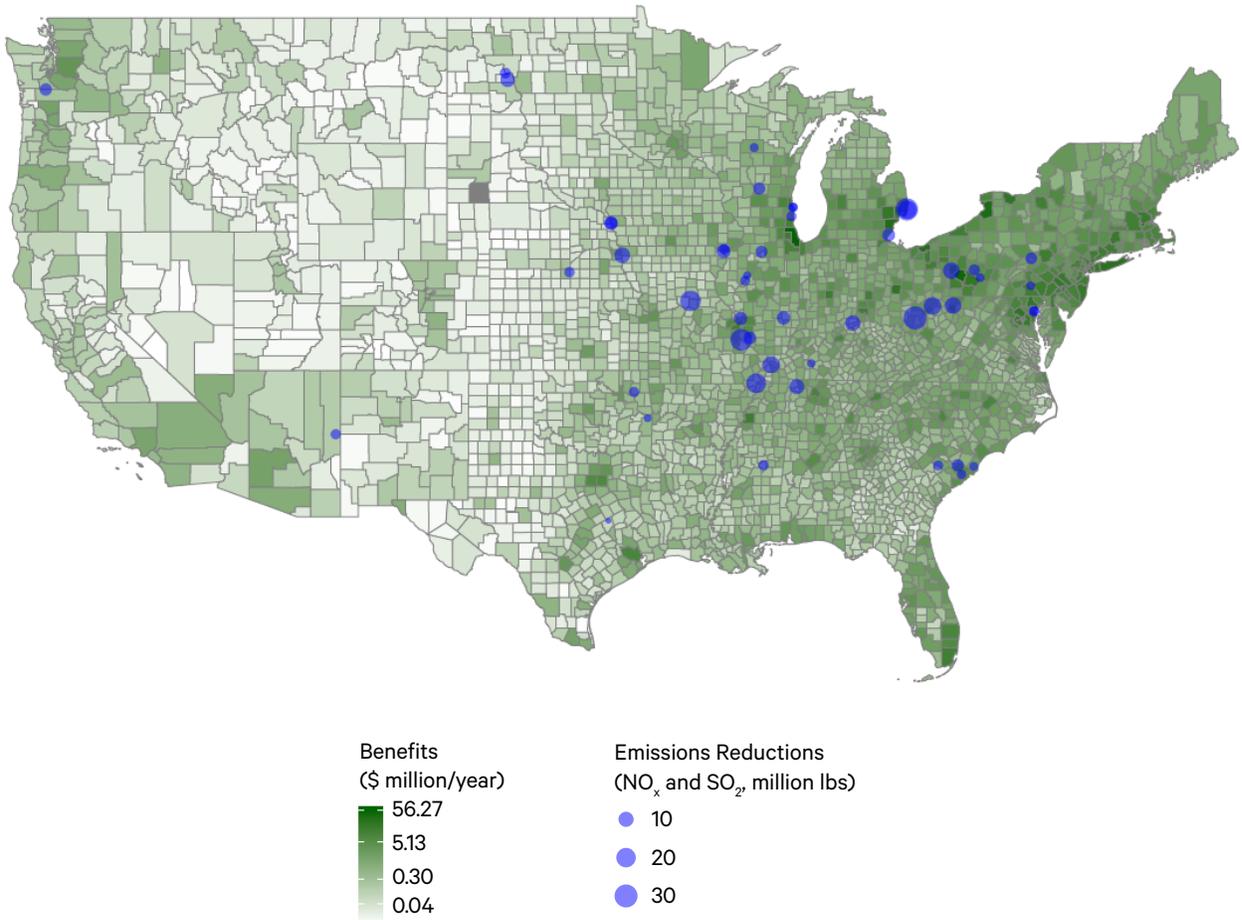
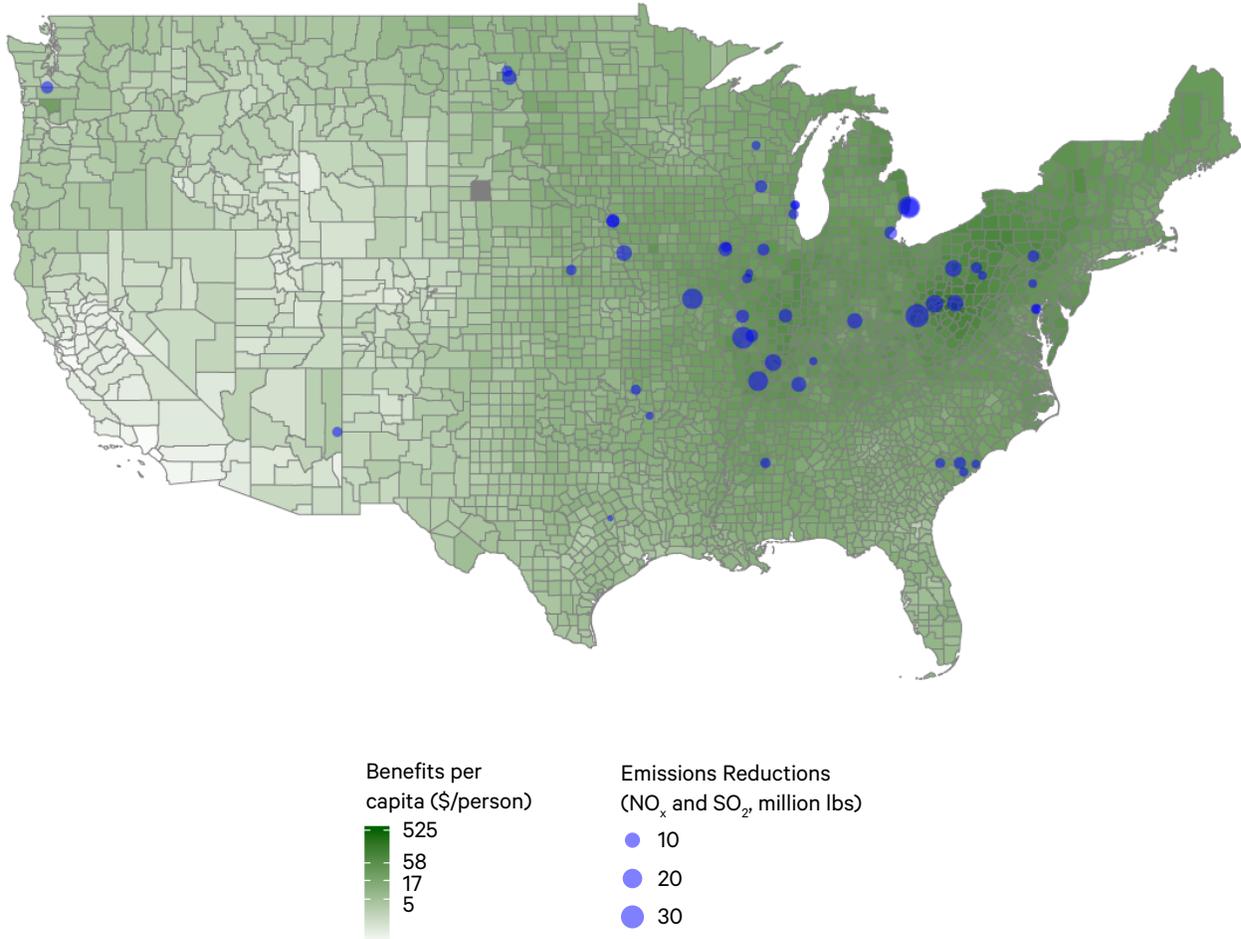


Figure 15. Distribution of Air Quality Benefits (dollars per capita) from SO₂ and NO_x, under the “Target Reductions” Scenario



Notes

- 1 While there are no academic papers looking at the performance of refined control, the story in Reuters (McLaughlin 2019) reports that total NO_x emissions actually increased at many plants but did not control for other factors (such as electricity output), or estimate emissions rates, which are the target of the refined coal legislation.
- 2 CS-ESP: cold side electrostatic precipitator; SCR: selective catalytic reduction; SDA: spray dryer absorber; FF: fabric filter baghouse.
- 3 The Senate bill was introduced by Sen. Hoeven (R-ND) Sen. Heitkamp (D-ND). The House bill was introduced by then-Representative and now-Senator Cramer (R-ND).
- 4 See IRS Corporation Income Tax Return Line Item Estimates, 2013, Form 8835, line 18. Available at <https://www.irs.gov/pub/irs-soi/13colinecount.pdf>
- 5 **Form EIA-923 Power Plant Operations report**, “EIA923_Schedules_2_3_4_5_M_11_2018_28JAN2019.xlsx”, Sheet “Page 1 Generation and Fuel Data”.
- 6 Emission rates are measured in mass of emissions per unit of fuel: pounds of pollutant per British thermal unit (btu). This aligns with IRS guidance which measures emissions relative to units of “useful thermal energy” (IRS Notice 10-54).
- 7 See, e.g., US EIA. 2017. **Today in Energy: Coal plants installed mercury controls to meet compliance deadlines.** September 18.
- 8 The Hg data begins later than the NO_x and SO₂ data because monitoring coincided with the implementation of the MATS rule. This means we have fewer observations for Hg emissions than for NO_x or SO₂.
- 9 We use data through November 2018. At the time of this analysis, EIA fuel consumption data was not yet available for December 2018.
- 10 It is not clear why sulfur emissions rose during this period. There was virtually no change in the sulfur content of this plant's coal during this period. There were also no installations or retirements of sulfur control technology at the plant during the period.
- 11 The remaining 10 percent include units that we could not match across EPA and EIA datasets, as well as units smaller than 25 MW of capacity and units in Alaska or Hawaii, which do not appear in the EPA CEMS data.
- 12 A small number of other units do not fall into any of these three categories, such as units that burn a mix of coal and natural gas. They are excluded from this table but included in our regression analysis.
- 13 We include other fuels to avoid omitted variable bias. Burning other fuels can also result in emissions. To the extent that the burning of other fuels is correlated with the burning of coal, this could threaten to bias the coefficients of interest. For example, if other fuels are a substitute for coal and hence negatively related, as they are at dual-fuel plants (and indeed coal and other fuel use are negatively related in our data) failing to include them in the regression will bias the estimated coal emissions rate down toward zero.
- 14 Cameron and Miller (2015) state that one should use at least 400 draws. The other benefit of using a bootstrapped distribution is that it allows us to test the compound joint hypothesis that the law's required reductions are achieved for both NO_x and either SO₂ or Hg. The standard Wald test is not designed to test such a hypothesis involving an “or” condition.

- 15 E.g., in one case our point estimate is a +24% higher emission rate, which would reject a two-tailed test for different from zero, but not a one-tailed test where the null hypothesis is that there are no reductions ($\beta > 0$). Similarly, our uncontrolled NO_x estimate of a -60% difference would easily reject a two-tailed test for -40%, but this would be a misleading interpretation. Formally, the null hypotheses are $\beta_{rc} > \beta_c$ and $\beta_{rc} < (1 - t)\beta_c$, where β_{rc} and β_c are the emissions rates for refined coal and regular coal, and t is the targeted reduction (20% or 40%). We conduct the p-values here using the bootstrapped distribution directly, but the results are essentially the same when running standard hypothesis tests using the covariance matrix of the bootstrap sample.
- 16 That plant is currently being acquired by a new owner that has announced “operational changes to reduce coal use by more than 50 percent initially” (The Southwest Times Record, [“OG&E buying Shady Point power plant”](#), January 2019).
- 17 This corresponds to a null hypothesis under which the parameters comply with the rules for eligibility criteria in the tax law. That is: $\beta_{RC}^{NO_x} < (1 - 20\%) \beta_C^{NO_x}$ **AND** $\beta_{RC}^{SO_2} < (1 - 40\%) \beta_C^{SO_2}$ **OR** $\beta_{RC}^{Hg} < (1 - 40\%) \beta_C^{Hg}$
- 18 This is out of 78 units that burned both refined and unrefined coal during the 2016–2018 sample period. We cannot reliably estimate NO_x or SO_2 reductions for about 30 of the units because of insufficient variation, primarily due to insufficient variation in one of the types of coal. The units excluded are either (1) units with a negative estimated coal emissions rate, (2) units with a coal emissions rate that is statistically indistinguishable from zero (usually due to insufficient observations), or (3) units with extremely limited observed coal use of one type or the other leading to extreme estimates well outside of their observed historical ranges. The number of identified units on Hg is smaller than for the other pollutants because there is less available data on Hg emissions due to the relative recency of reporting requirements for Hg.
- 19 Details on the COBRA model can be found at <https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool>.
- 20 For example, for a plant with NO_x controls that burned entirely refined coal in 2017, we adjust NO_x emissions upwards by factor of $1/(1 - 12.5\%)=1.14$. For plants that burned a mix of fuels in 2017, the calculation is slightly more complicated to account for the fact that observed 2017 emissions derive from both refined coal and other fuels.
- 21 $\$3.5/\text{MWh} = \$7/\text{ton} \cdot (10 \text{ mmbtu}/\text{MWh}) / (20 \text{ mmbtu}/\text{ton})$
- 22 See, for example, https://www.eia.gov/energyexplained/index.php?page=coal_prices.
- 23 For example, the 2018 SO_2 auction clearing price was $\$0.06/\text{ton}$, down from $\$0.11/\text{ton}$ in 2015, which in turn was down from $\$36/\text{ton}$ in 2010, which in turn was lower than $\$690/\text{ton}$ in 2005. See <https://www.epa.gov/airmarkets/so2-allowance-auctions>.
- 24 See EPA, “Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards”, which estimates quantifiable benefits of only $\$4$ – $\$6$ million from a 20 ton/year reduction in Hg (3% discount rate, see Tables ES-2 and ES-4). This estimated benefit is dwarfed by $\$37$ – $\$90$ billion in co-benefits from reductions in other pollutants.
- 25 According to an industry observer quoted in a Reuters article (<https://www.reuters.com/article/us-mylan-coal-insight/drugmaker-mylan-gets-boost-from-unlikely-source-coal-idUSKBN19CODW>), the total costs amount to 60% of the value of the credit of $\$7$ per ton. That figure includes an adjustment for the benefit of claiming a tax deduction for operating losses arising from operating without pre-tax revenue, which is not a real cost. Thus, real economic cost (denoted c) plus the loss from purchasing and reselling coal to the power plant at a discount (denoted d), together after taxes $(1 - t)$ equals 60% of $\$7$: $(c + d)(1 - t) = 0.6 \cdot \7 . Solving for c yields:

$c = (0.6 \cdot \$7) / (1 - t) - d$. According to another article (<https://www.reuters.com/investigates/special-report/usa-coal-wallstreet/>), the discount ranges “anywhere from 75 cents to \$2 per ton”. Using the historical corporate tax rate of 35 percent and plugging these values in yields estimates of c between \$4.46 and \$5.71 per ton, or about \$5 per ton.

- 26 These costs include both variable costs and amortized fixed costs.
- 27 Our estimates suggest that refined coal may reduce Hg emissions by 0.06-0.08 tons per year in practice, or 0.46 tons per year if the 40% reductions were actually achieved. These impacts are much smaller than the reductions of 20 tons per year that EPA valued at \$4-6 million in present value (EPA, “Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards”, Tables ES-2 and ES-4). Therefore, adding in the benefits of Hg reductions is unlikely to change our results very much. That said, EPA was unable to quantify all the benefits of Hg reductions.

