Policy Monitor

How Stringent Are the US EPA's Proposed Carbon Pollution Standards for New Power Plants?

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Introduction

The passage of national climate policy legislation has proven elusive in the United States. In one of the leading efforts, in 2009, the US House of Representatives passed the American Clean Energy and Security Act. Although the legislation did not become law, it would have established targets for the reduction of domestic carbon dioxide (CO_2) emissions and achieved them primarily through a cap-and-trade system. Among the key targets were a 17 percent reduction in emissions from 2005 levels by 2020 and an 80 percent reduction by 2050. In the Senate, the American Power Act was introduced as a draft bill in 2010 and also sought to establish a cap-and-trade system with similar emission targets. However, a vote was never taken despite much political attention during the summer of 2010.

In the absence of legislation, responsibility for implementing climate policy has fallen to the US Environmental Protection Agency (EPA). The process began in 2007, when the Supreme Court ruled that CO_2 and other greenhouse gases (GHGs) qualify as pollutants under the Clean Air Act. The EPA was ordered to determine if these pollutants pose a threat to public health and welfare, in which case regulation would be required (see *Massachusetts v. EPA,* 549 U.S. 497, 2007). In 2009, the EPA issued the finding that current and projected concentrations of GHGs do in fact endanger public health and welfare. Then in 2010, the EPA agreed to issue rules for regulating GHG emissions from fossil fuel electricity generating units (EGUs).

Rules were first proposed on March 27, 2012, when the EPA released for public comment its Proposed Carbon Pollution Standard for New Power Plants (hereafter originalCPS). The EPA received more than 2.5 million public comments on the originalCPS and subsequently withdrew the proposal upon issuing a revision on September 20, 2013, as part of President Obama's Climate Action Plan. The revised rules (hereafter revisedCPS) are currently under review.

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The EPA is also working on proposed rules for *existing* power plants, which are to be issued by June 1, 2014.

Immediately following the release of the originalCPS, we carried out an analysis and submitted for public comment an evaluation of the emission standard in the proposed rule relative to the emission rates of existing and proposed EGUs in the United States (Kotchen and Mansur 2012). We focused on this question: How stringent is the EPA's proposed carbon pollution standard for new power plants? In this article, we report the original findings of our 2012 evaluation and update the analysis to reflect differences between the originalCPS and the revisedCPS.

In the next section, we provide background on the two EPA proposals and how they differ. In the subsequent section, we describe our basic approach and the data sets used. We then present results based on the implications of the proposed emissions standards for power plant heat rates, followed by our main results that compare the actual emission rates of EGUs with the rates specified in the proposed rules. We also consider the effects of the heterogeneity of EGUs (based on capacity and utilization rates), along with geographic differences by state. We conclude with a summary and discussion of the carbon pollution standards more generally.

Basics of the Proposed Rules

The originalCPS applied only to *new* fossil fuel EGUs that generate electrical power for sale and are larger than 25 megawatts (MW). Because the rule focused on generators that service baseload demand, the rule did not apply to stationary simple cycle turbines that are typically used to meet peak demand.[1] The primary requirement of the originalCPS was that EGUs comply with an output-based emissions standard of 1,000 pounds of CO_2 per megawatt-hour of gross generation (lbs CO_2/MWh gross) on an annual basis. Supplementary technologies to reduce CO_2 emissions, such as carbon capture and storage (CCS), were permitted to meet the standard, and EGUs that employed CCS would have the option of meeting the CO_2 emissions target using a 30-year average of emissions. Further details on the originalCPS are available from the EPA (2012b, 2012c, 2012d).

The fundamental difference between the originalCPS and the revisedCPS is that the revisedCPS sets separate emission standards for natural gas and coal-fired EGUs. The natural gas standards depend on the size of the unit. For the larger natural gas units—those with size ratings greater than 850 million British thermal units per hour (mmBtu/hour)—the standard remains unchanged at 1,000 lbs CO_2/MWh gross. For smaller natural gas units—those with size ratings less than 850 mmBtu/hr—the standard is raised to 1,100 lbs CO_2/MWh gross. Natural gas units exempt from the standard are those that sell less than a third of their potential power to the grid, which as we show, will generally include the simple cycle turbines that meet peak demand. For coal-fired EGUs, there are two possible emission standards. The first is the same as the standard for smaller natural gas units (1,100 lbs CO_2/MWh gross per year). The second is closer to the original proposal (1,000 to 1,050 lbs CO_2/MWh gross), but compliance would be required over a seven-year average rather than annually. The second option is intended to

[1]Baseload demand for electricity refers to the base line level of demand that is relatively constant throughout the day. In contrast, peak demand refers to the predictable increases in electricity demand at certain times of day in the morning and evening.

provide flexibility for the phase-in of CCS. Further details on the revisedCPS are available from the EPA (2013a, 2013b, 2013c).

Analytical Approach and Data Collection

In order to evaluate the stringency of the proposed rules, we compare the EPA's proposed emission targets with the emission rates of existing and proposed EGUs. Because future changes in technology and market trends are uncertain, comparisons with existing units have predictive limitations, but they also have the advantage of being based on the actual utilization of current technologies. We examine all of the natural gas and coal units throughout the continental United States with at least 25 MW capacity and for which reliable data are available on hourly emissions between 2008 and 2010, for a total of 3,301 EGUs. We then conduct a more focused study of EGUs that commenced operation more recently—that is, those that first came online in 2006 or more recently. We also consider the pattern of proposed EGUs through 2020 and how the standards would likely have different impacts across states.

Emissions Data

We obtained CO_2 emissions data from the EPA's Continuous Emissions Monitoring System (CEMS) program, which is the same data the EPA proposes to use for the monitoring and enforcement of the proposed rules. CEMS includes data on the flow emissions of CO_2 in lbs/hour from participating units.[2] All units over 25 MW capacity are required to participate in CEMS. Along with emissions data, CEMS contains hourly data on each unit's gross generation, which includes the generation that is sold plus the power used to operate the plant itself. Using the hourly data from 2008 through 2010, we calculated the average emission rate (lbs/kWh gross) over this period for each unit, using only hours for which both emissions and generation are greater than zero.

Characteristics of EGUs

We collected data from the Energy Information Administration (EIA) on the basic characteristics of EGUs. Specifically, we used the Annual Electric Generator Report (Form EIA-860), which includes information about existing generators at electric power plants with 1 MW or more of capacity.[3] The variables of particular interest for our analysis include the primary fuel source (either natural gas or coal), the year of first scheduled operation, and the state in which the unit is located. We also distinguish between natural gas generators that are based on simple cycle gas turbines (SCGTs) or combined cycle gas turbines (CCGTs).[4] SCGT units generate electricity with one gas-powered cycle, whereas CCGT units combine a gas turbine with a steam turbine to generate electricity with the waste heat. It is important to note that CCGT units are

[2]These data are publicly available, and detailed information about the CEMS program can be found online at http://www.epa.gov/airmarkets/emissions/continuous-factsheet.html.
[3]Further information about Form-860 and the data files themselves are publicly available and posted online at http://www.eia.gov/cneaf/electricity/page/eia860.html.
[4]Because some plants were originally constructed as SCGT units and later converted to CCGT, our categorization is based on their status from 2008 through 2010, the years for which we use emissions data.

generally more efficient than SCGT, with the former meeting baseload demand and the latter meeting peak demand.

Merging the Data and Data Issues

We merged the EPA and EIA data sets. In the vast majority of cases, matches were possible because of a direct correspondence between EPA and EIA plant-unit identification codes. In other cases, differences in the EPA and EIA codes meant that matches were only possible at the plant level. However, in most cases, line-by-line comparisons of these observations still allowed us to make associations at the level of specificity required for our analysis including merged data on unit emissions, energy source, CCGT or SCGT technology, year of first scheduled operation, and state.

To focus on units of the size that would be subject to EPA's proposed rules, we restricted the sample to EGUs with at least one hour's gross generation in excess of 26.5 MWh between 2008 and 2010. We use this measure of gross generation rather than nameplate capacity of a unit because nameplate capacity is unavailable for observations merged at the plant level (although this should not cause any difficulties for the analysis). We set the cutoff at 26.5 MWh because the CEMS data measures gross generation, and the proposed rules are based on measures of capacity equivalent to 25 MW of net generation. We thus allow for a 5 percent difference between net and gross generation.[5]

We also addressed a data issue that pertains to CEMS reporting for CCGT units. It is important to recognize that reporting for CCGT units includes electricity generation from the steam cycle and that it is accurately associated with gas units for plants where the steam cycles are pooled. EPA officials confirm that most utilities report generation from the steam cycle and allocate it to units with the associated emissions.[6] However, for CCGT units that first began operating between 2006 and 2010—which are the ones most important for our analysis—we used information from the EPA that identifies specific EGUs with incomplete reporting, and we dropped these observations (six in total) from the parts of our analysis that are based on emission rates.[7]

The total number of EGUs included in our final sample is 3,301. Among these units, 896 (or 27 percent) are coal fired and 2,405 (or 73 percent) are natural gas fired. The natural gas EGUs are composed of 878 CCGT units and 1,527 SCGT units.

Implications of Emission Standards for EGU Heat Rates

Before proceeding to our analysis of actual emission rates among EGUs, it is helpful to consider what the proposed emissions targets imply for EGU heat rates that measure thermal efficiency

[5]This number is based on an empirical average of the difference between net generation for power plants from the CEMS data and gross generation from the EIA's Form 923 data. We found a 5 percent difference. The EIA Form 923 data is available at http://www.eia.gov/electricity/data/eia923/.

[6]This is consistent with the guidelines in Part 75 of the Code of Federal Regulations. Moreover, the 2010 Emissions Monitoring Policy Manual (EPA 2012a) seeks to partially address this concern with a uniform set of reporting guidelines.

[7]These data are not publicly available and were obtained directly from utilities as part of the EPA's analysis in support of the proposed rules. We are grateful to Kevin Gulligan, Christian Fellner, and Nick Hutson of the EPA for sharing these data.

in terms of the fuel-based heat supplied to a power plant per unit of energy output. Lower heat rates indicate greater efficiency, and there is a 100 percent efficiency lower bound at 3,412 Btu/kWh. Because natural gas has an emissions factor of 117 lbs CO_2/mmBtu, the emissions targets of 1,000 and 1,100 lbs CO_2/MWh imply gross heat rates of 8,547 and 9,402 Btu/kWh, respectively, for natural gas units.[8] For coal, the emissions factors are approximately 205 and 213 lbs CO_2/mmBtu for bituminous and subbituminous coal, respectively, which imply heat rates for coal units of 4,878 and 4,695 Btu/kWh for a standard at 1,000 lbs CO_2/MWh, or 5,366 and 5,164 Btu/kWh for a standard at 1,100 lbs CO_2/MWh.

These figures can be used to indicate how the EPA's proposed standards line up with existing generation technologies. To illustrate, we compare the heat rates just derived with the average heat rates for coal and natural gas generation in the United States for 2010.[9] We find that the average heat rate for coal units is 9,894 Btu/kWh, which is roughly twice the heat rates implied by the proposed standards, assuming the units were to meet the target with more efficient generation rather than CCS. The average comparable heat rate for natural gas units is 7,776 Btu/kWh, which falls below the emissions standards. This heat rate includes both SCGT and CCGT units. While there can be significant differences in the emissions from these two technologies, as we will show, it is known that new CCGT units can achieve a gross heat rate of approximately 6,667 Btu/kWh (net of 7,000 Btu/kWh), which clearly falls below the proposed targets.

Comparison of Observed CO_2 Emissions with the Proposed Standards

We now turn to our data on *observed* emission rates among EGUs in order to make comparisons with the EPA's proposed standards. Observed emission rates have the analytical advantage of reflecting how current technology is actually utilized and thus provide a useful basis upon which to evaluate the stringency of the proposed standards.

Observed Emission Rates

Recall that our emissions data cover the period of 2008 through 2010. The mean emission rate among all coal plants in our data set is 2.14 lbs/kWh. For natural gas generators, the mean emission rate is 1.09 lbs/kWh for CCGT units and 1.41 lbs/kWh for SCGT units. As clearly illustrated in Figure 1, which plots the three-year mean emission rate for every EGU against the year of first operation, coal units have higher emission rates over time, followed by SCGT, and then CCGT units.[10] The CCGT units have come online more recently, with a substantial increase in 2000, and the more recent CCGT units appear to have lower emission rates.

[8]This figure is derived by dividing the relevant regulatory rate in lbs CO_2/MWh by the fuel emissions factor in lbs CO_2/mmBtu, and then multiplying by 1,000 to convert mmBtu/MWh to Btu/kWh.
[9]These statistics are from Table 5.3 of the EIA's *Electric Power Annual*, 2010, and they are available online at http://www.eia.gov/electricity/annual/html/table5.3.cfm. Adjustments from the reported net heat rates to gross heat rates are made assuming a 5 percent difference between the two heat rates to account for the electricity needed to operate the unit.
[10]In some cases where CCGT units are based on plant conversions, the date of first operation applies to the plant itself, not when it first began operating as a CCGT unit, because information about the timing of the conversion is not available.

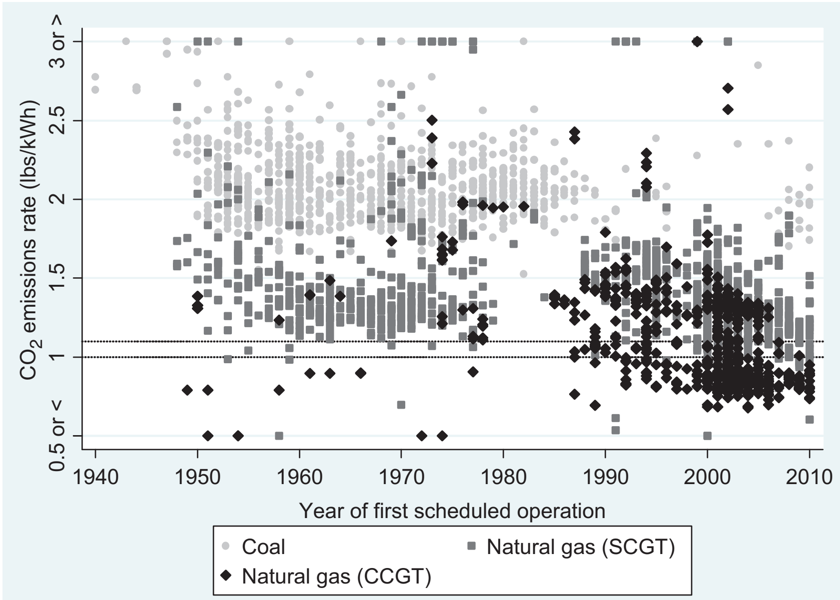

Figure 1 Average gross CO_2 emission rates 2008–2010 against year of first scheduled operation for coal, CCGT, and SCGT units.
Notes: Horizontal reference lines indicate different proposed emission rate standards.
Source: Authors' calculations.

While much of this trend regarding CCGT units is due to greater efficiency, some of the difference in emission rates over time may also be due to incomplete reporting.[11]

Figure 1 also includes horizontal dashed lines that correspond to the emission rate standards of the proposed rules. The lower line at 1 lbs/kWh (equivalent to 1,000 lbs CO_2/MWh gross) represents the standard for all units in the originalCPS as well as the standards in the revisedCPS for larger natural gas units and possibly coal units with compliance over a seven-year period. The higher line at 1.1 lbs/kWh (equivalent to 1,100 lbs CO_2/MWh gross) is the standard in the revisedCPS for smaller natural gas plants and coal plants. The figure thus offers a rough indication of which existing units would meet the two standards on an annual basis—that is, those units below the corresponding reference line. Keep in mind, however, that the originalCPS did not apply to SCGT units, and, as we will see, the revisedCPS will generally not apply to them either. Thus the most interesting observation to make at this point is the large number of recently constructed CCGT units that are likely to meet the standard of the revisedCPS.

Distributions of Observed Emission Rates

We now consider emission rate *distributions* in order to show more precisely how many units of each type would potentially meet the different standards. A useful way to summarize these data is to plot cumulative distribution functions (CDFs) that indicate the proportion of units that have emissions rates that are less than each rate indicated on the horizontal axis of the graphs in

[11]Recall that units with incomplete reporting (and therefore upwardly biased emission rates) have been removed from the data set for units that first began operation between 2006 and 2010, but this is not possible for older units because the information about reporting is unavailable.

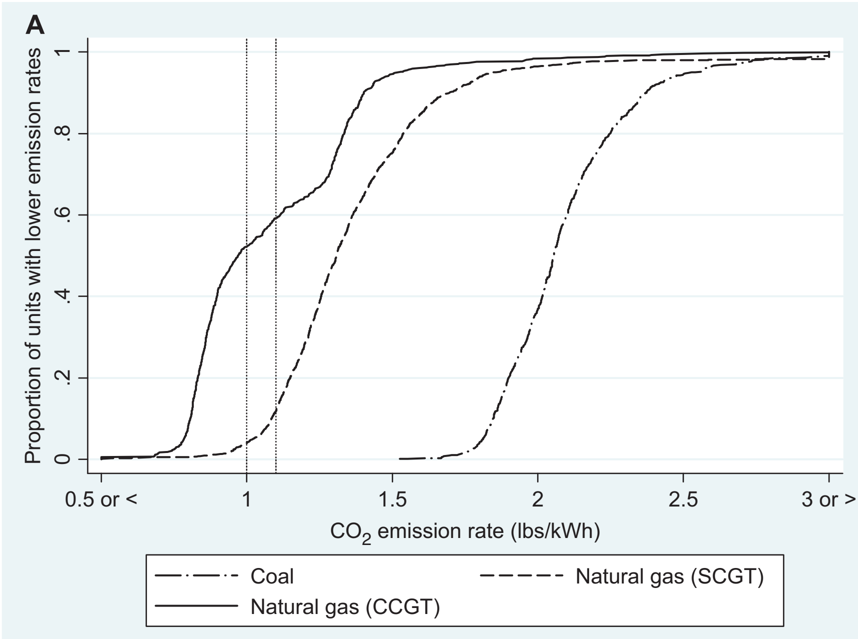

Figure 2A Cumulative distribution functions of average gross CO_2 emission rates 2008–2010 for all coal, CCGT, and SCGT units.
Notes: Vertical reference lines indicate different proposed emission rate standards.
Source: Authors' calculations.

Figures 2A and 2B. Figure 2A includes all of the units in the data set and shows separate CDFs for coal, CCGT, and SCGT units. Here again, it is clear that coal units have significantly higher emission rates, and with current technology, no coal units would meet either of the proposed standards without some form of CCS. Even though the standards are not intended to apply to SCGT units, Figure 2A indicates that their emission rates are generally much higher than the proposed targets: only 4 percent (12 percent) of all the operating SCGT units have emission rates of less than 1 lbs/kWh (1.1 lbs/kWh). CCGT units perform significantly better: 52 percent (59 percent) of all the operating CCGT units have emission rates of less than 1 lbs/kWh (1.1 lbs/kWh), although this statistic includes some observations from before 2006 that may have incomplete reporting.

Recall, however, that the CPS applies only to newly constructed units. We therefore repeat the same analysis including only those units that commenced operation between 2006 and 2010, as this provides a more recent sample. In addition, because only 19 coal units commenced operation during this period (with an average emission rate of 1.97 lbs/kWh), we report results only for natural gas units. Figure 2B, which presents the cumulative distribution functions for 82 CCGT units and 168 SCGT units, indicates that a higher proportion of these more recently constructed natural gas EGUs would meet the proposed standards. The CCGT units are of particular importance, and we found that 90 percent (95 percent) of them have emission rates less than or equal to 1 lbs/kWh (1.1 lbs/kWh).[12] In the next section, we consider heterogeneity of emissions and standards based on the size of the natural gas EGUs.

[12]All six of the CCGT units that were dropped because of incomplete reporting have emissions rates greater than 1 lbs/kWh, with a mean of 1.30 (ranging from 1.25 to 1.35).

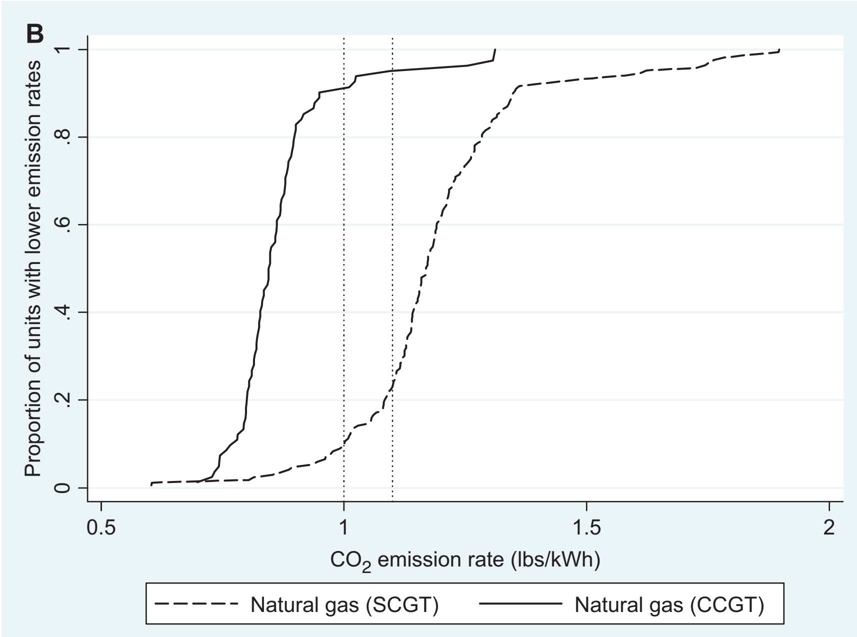

Figure 2B Cumulative distribution functions of average gross CO_2 emission rates 2008–2010 for CCGT and SCGT units that commenced operating between 2006 and 2010.
Notes: Vertical reference lines indicate different proposed emission rate standards.
Source: Authors' calculations.

Robustness Based on Predicted Emissions

To check the robustness of these results, we return to heat rates and examine the *predicted* emissions of CCGT units. In particular, we use the EPA's National Electric Energy Data System (NEEDS) database to predict emission rates based on the reported heat rates of those CCGT units that commenced operation between 2006 and 2010 and are larger than 25 MW.[13] This yields 120 observations of which 115, or 95.8 percent (116, or 96.6 percent), have emission rates less than 1 lbs/kWh (1.1 lbs/kWh), with adjustments from net to gross heat rates of 5 percent. Although this figure is higher than our earlier estimates, it is important to recognize that this estimate is based on predicted rather than actual emissions. In contrast, as noted earlier, the CEMS data are based on actual emissions and have the additional advantage of being based on gross rather than net generation, thereby matching how the emission standards would be applied in practice. Also recall that the revisedCPS has different standards for natural gas units of different sizes, which is one of the variables that we now consider in more detail.

Heterogeneity of Emissions Based on Capacity and Utilization

In order to understand differences among EGU emission rates and the potential compliance of new units with the proposed standards, we next examine the effect of EGU capacity and

[13]These data are posted at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_MATS.xlsx, with descriptions at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Guide_to_NEEDSv410.pdf.

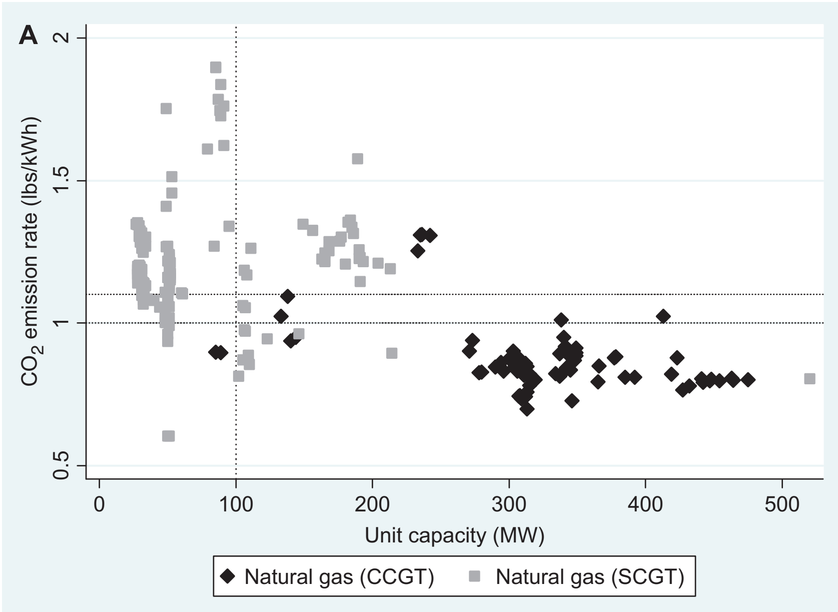

Figure 3A Scatter plot of average gross CO_2 emission rate 2008–2010 against unit capacity for all CCGT and SCGT units that commenced operating between 2006 and 2010.
Notes: Horizontal reference lines indicate different proposed emission rate standards.
Source: Authors' calculations.

utilization on emission rates. We measure capacity using a unit's maximum hourly gross generation between 2008 and 2010.[14] We measure utilization rate as the ratio of a unit's average hourly electricity generation over its capacity. Figures 3A and 3B plot emission rates against capacity and utilization rate, respectively, for the newer natural gas units—that is, those first operating in 2006 or more recently.

CCGT Units

We first discuss the results for the CCGT units. Figure 3A appears to indicate a pattern where smaller CCGT units have higher emission rates than larger units. We observed this pattern in our earlier analysis of the originalCPS (Kotchen and Mansur 2012), which did not set emission rates that depend on a unit's capacity. But the revisedCPS does set different rates based on unit capacity, and Figure 3A shows how the proposed standards compare to current emission rates. The EPA (2013a) explains that the size threshold of 850 mmBtu/hr corresponds to approximately 100 MW capacity, which is indicated by the vertical reference line in Figure 3A. This means that for the revisedCPS, the relevant comparison for units less than 100 MW is the 1 lbs/kWh rate, and for units greater than 100 MW it is the 1.1 lbs/kWh rate. Note that only two CCGT units are small enough to qualify for the higher emission rate, yet they both satisfy the lower emission rate.

[14]We use this measure rather than the unit's nameplate capacity because, as described earlier, nameplate capacity is not available for all units.

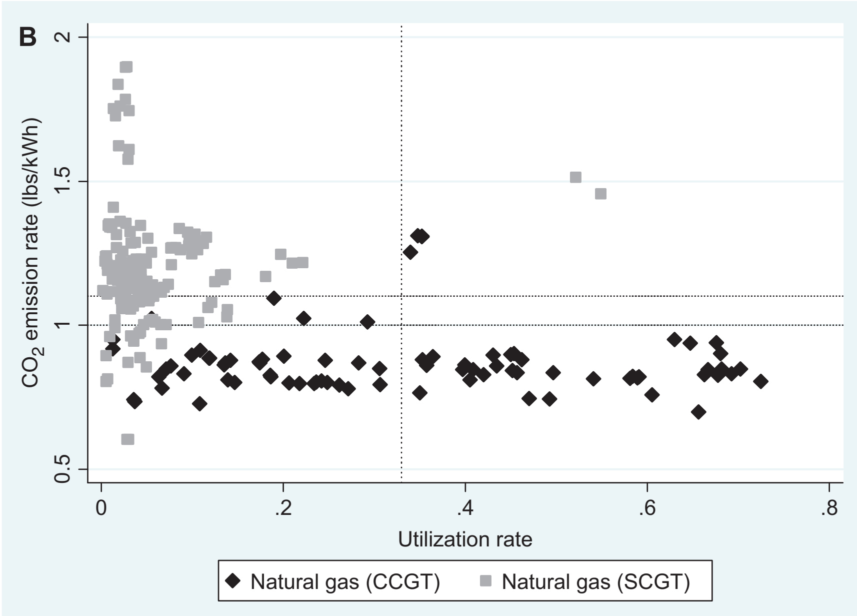

Figure 3B Scatter plot of average gross CO_2 emission rate 2008–2010 against unit utilization rate for all CCGT and SCGT units that commenced operating between 2006 and 2010.
Notes: Horizontal reference lines indicate different proposed emission rate standards.
Source: Authors' calculations.

Figure 3B also plots the emission rate against the utilization rate. Recall that the revisedCPS exempts all natural gas units that sell less than a third of their potential power to the grid. This exemption is reflected by the area on the left side of the vertical reference line in Figure 3B, which indicates that all of the CCGT units would comply with the relevant emission standard. The units with noncompliant emission rates just miss the exemption, however. The other observation to make about Figure 3B is that there does not appear to be any relationship between emission rates and the utilization rates for CCGT units, at least when this relationship is considered in isolation.

To account for the effects of capacity and utilization simultaneously, we estimate a multivariate regression model using only the 82 CCGT units in operation since 2006. In general, we find that both capacity and the utilization rate have negative and statistically significant effects on a unit's emission rate. More specifically, in a regression model of the emission rate on capacity and utilization, we find that a 100 MW increase in capacity is associated with a 0.074 decrease in the emission rate, and a 10 percentage point increase in the utilization rate is associated with a 0.012 decrease in the emission rate.[15]

[15]The specific model that we estimate is the following:

$$CO_2Rate = \underset{(0.06)}{1.14} - \underset{(0.15)}{0.74} \times Capacity(\text{1000s MW}) - \underset{(0.06)}{0.12} \times Utilization,$$

where standard errors are reported in parentheses. The overall R-squared is 0.23.

SCGT Units

Turning now to the SCGT units, there does not appear to be any relationship between emission rates and either the capacity or utilization of SCGT units. The main reason that we include SCGT units in Figures 3A and 3B is to illustrate differences in capacity and utilization rates. There are clear differences between SCGT and CCGT utilization rates. This is because, as mentioned earlier, the former are typically used to meet peak demand. Recall that the originalCPS exempted all SCGT units from any emission standard. However, at the time, the EPA (2012c) requested comments on whether it would be preferable to have an exemption that is based on a utilization threshold of one third, which is what has been proposed in the revisedCPS. Figure 3B shows that the exemption is roughly the same whether it is based on SCGT units or the one-third utilization rate (with the exception of 2 units).

Proposed EGUs and Geographic Differences

We now consider trends in proposed EGUs, some of which could be subject to the final rules. We use data from Form EIA-860 that includes information on units scheduled for initial commercial operation within 10 years of the specified reporting period. Our data on proposed units cover 2011 through 2017 and consist of all scheduled coal and natural gas EGUs with nameplate capacity of at least 25 MW. We report characteristics of the EGUs in general, followed by a closer look at differences among states.

Trend in Proposed EGUs

Figure 4 shows the distribution of existing and proposed EGUs by year of scheduled first operation since 2006.[16] We include both the recently operating and proposed units to make comparisons between groups. Note that compared to the 2006–2010 period, the set of proposed EGUs consists of relatively few coal units and more CCGT than SCGT units.

Focusing now on CCGT units, because the vast majority of SCGT units will be exempt and coal units will not come close to any of the proposed standards without CCS, Figure 5 plots the distribution of CCGT unit capacity by year of first scheduled operation.[17] The figure shows a trend toward smaller units. We have shown previously that this trend would have made the originalCPS more stringent than originally anticipated because smaller units have higher emission rates, and there was a single emission standard (Kotchen and Mansur 2012). But the revisedCPS seeks to address this issue by setting a higher emission standard at 1.1 lbs/kWh (up from 1 lbs/kWh), thereby making compliance easier for units with less than roughly 100 MW of capacity.

[16]Units are designated as existing or proposed based on the most recent Form EIA-860 data. We use the EPA definition of CCGT units following the Part 75 manual (EPA 2012a) for allocating the steam turbine capacity to associated gas turbines.
[17]It is worth mentioning again that the figures for MW capacity of existing units (2006–2010) are based on maximum hourly gross generation, not gross adjusted nameplate capacity.

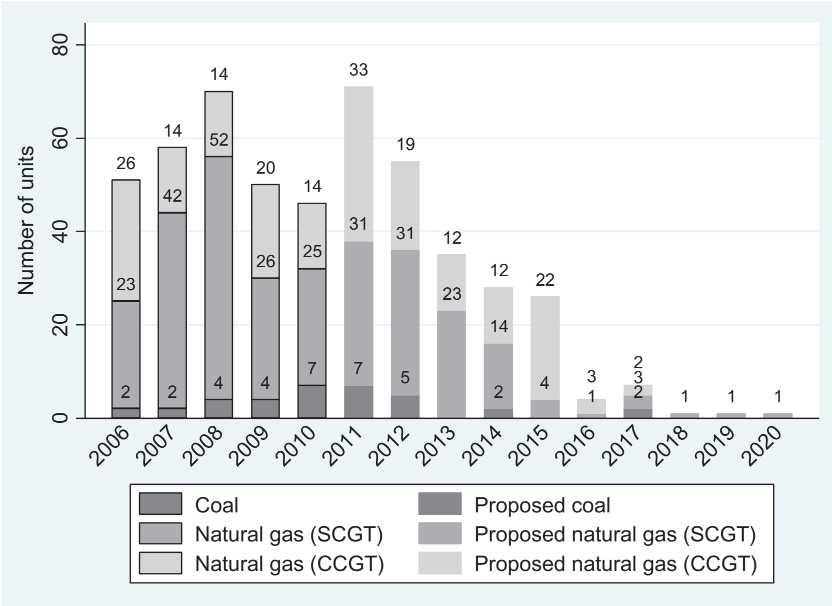

Figure 4 The distribution of coal and natural gas EGUs greater than 25 MW capacity by year of scheduled first operation since 2006.
Notes: Existing and proposed units based on EPA and EIA data.
Source: Authors' calculations.

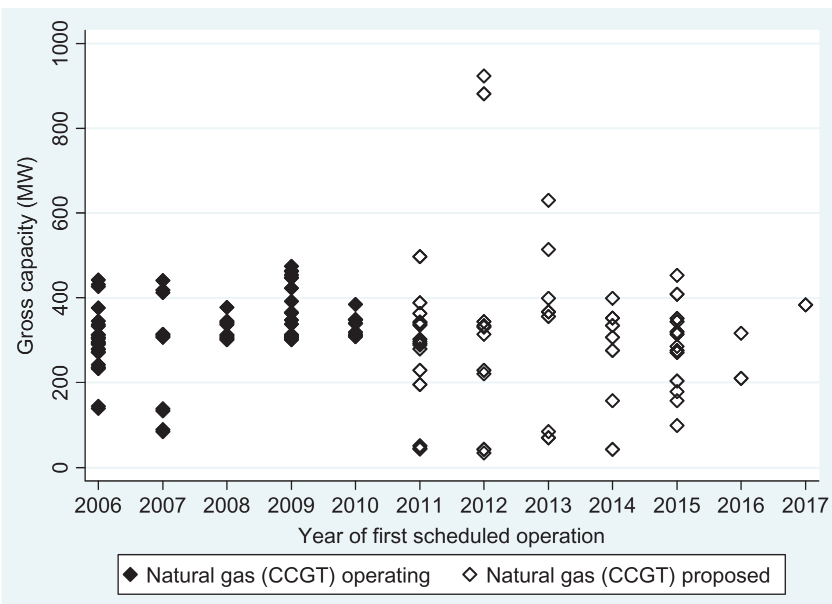

Figure 5 Natural gas CCGT unit capacity (MW) against year of first scheduled operation, existing and proposed, 2006–2017.
Notes: Existing and proposed units based on EPA and EIA data.
Source: Authors' calculations.

Trends Among States

To identify patterns across states, we examined basic descriptive information for all EGUs recently constructed or proposed in each state since 2006. Figure 6 shows the breakdown for each state by unit type and whether the unit is classified as existing or proposed. States toward

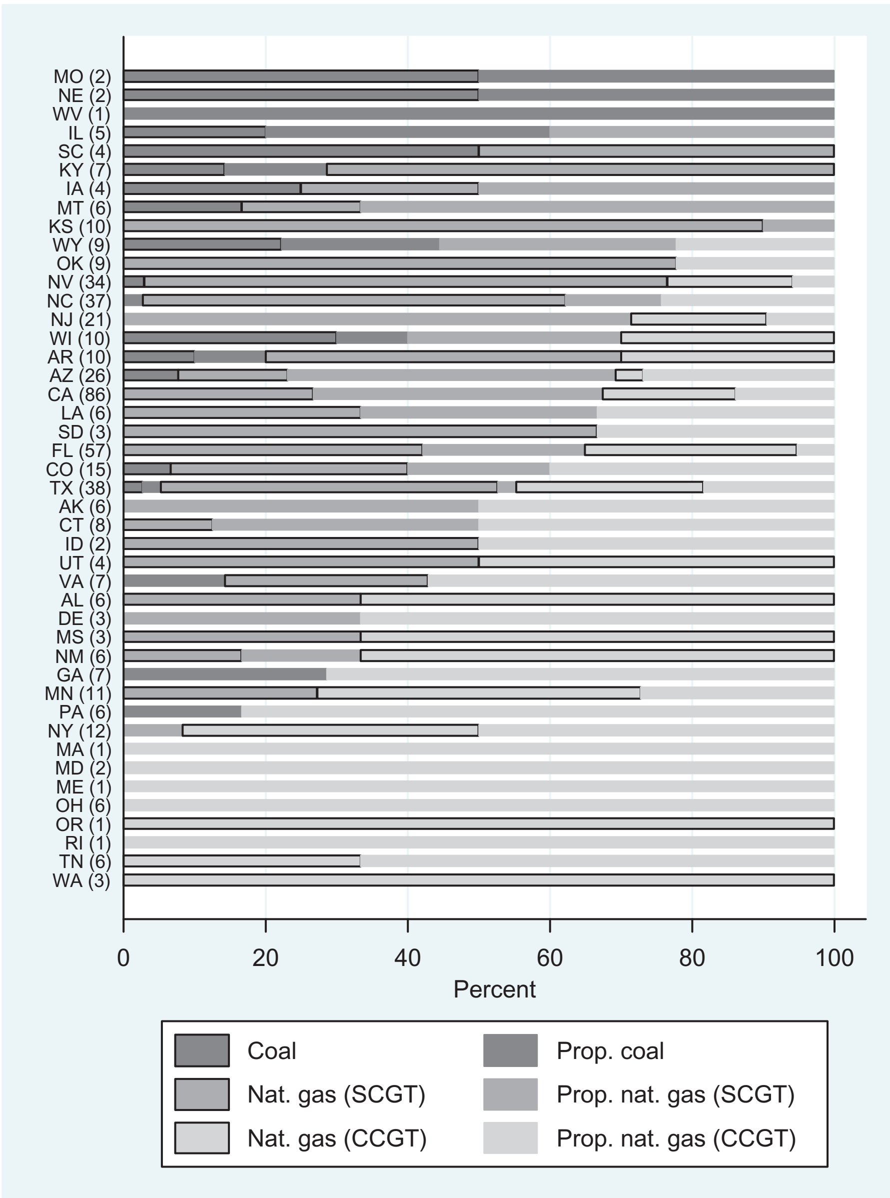

Figure 6 State-level percentages and total number of EGUs with scheduled first operation since 2006 by coal, CCGT, SCGT (existing and proposed).

Notes: Total numbers of EGUs by state are in parentheses following the state abbreviation. Indiana, Michigan, North Dakota, New Hampshire, and Vermont have no units and are thus not included.

Source: Authors' calculations.

the top of the figure use primarily coal plants while those toward the bottom use primarily natural gas CCGT technology. States in the middle of the list have a more mixed profile that includes natural gas SCGT technology. These states also tend to have a greater number of existing and proposed units since 2006 (see numbers in parentheses next to state abbreviations).

The pattern in Figure 6 has important implications for the potential distribution of costs of the proposed standards across states, assuming the actual construction of EGUs would follow a similar pattern. When choosing which of the available technologies to use for new EGUs, utility companies have preferences that reflect differences in operating, construction, and regulatory costs by state. One important factor is the relative price of fuel. In 2010, for example, the price of coal mined in Virginia was approximately \$100 per ton while the price of coal mined in Wyoming was less than \$13 per ton (EIA 2013a). Natural gas prices also show heterogeneity, although to a lesser degree.[18] Appendix Table 1 shows the 2010 quantity-weighted state average of coal and natural gas prices reported by utilities. On a Btu basis, natural gas is just 30 percent more expensive than coal in South Carolina while in the Great Plains coal is a significantly less expensive fuel. What is more, these cost differences tend to carry over into electricity prices, with those locations with relatively less expensive coal tending to have lower electricity rates. In fact, the 2010 average price of electricity in the states that plan to build a coal plant is 8.3 cents/kWh compared to 10.7 cents/kWh in all other states (EIA 2011).[19]

While these factors may contribute to differences in the costs of the proposed emission standards across states, quantitative estimates of these costs will depend critically on the long-run average costs of new construction for each type of EGU and whether the final rule ultimately affects the choices among them. EPA has argued that the standards are not expected to have notable costs because plants that will be built over the next decade are expected to meet the targets even in the absence of the rule (EPA 2013b, 2013c). In the meantime, however, the political economy of support for US climate policy is clearly reflected in Figure 6, as states with recently constructed or proposed coal units are those that have typically been the most opposed to policies that seek to reduce GHG emissions (Aldy, Kochen, and Leiserowitz et al. 2012).

Summary and Conclusions

This article has examined the emission rates of existing EGUs throughout the United States in order to gain a better understanding of the potential stringency of the EPA's proposed carbon pollution standards for new EGUs. Although the rule would target newly constructed units rather than those currently in operation, it is useful to compare the target emission rates with the actual emission rates from recently constructed power plants.

We have found that no coal-fired EGUs would comply with the proposed emission targets of either the originalCPS or the revisedCPS without taking advantage of future innovations in

[18]In 2010, natural gas prices ranged from \$4.57 in Oregon to \$6.54 in Florida (EIA 2013b).
[19]Of course, eliminating new coal plants in response to an emissions standard does not imply that rates in low-cost states would rise to the level of the other states. This is because electric utilities are regulated in various ways at the state level, with conditions imposed on decisions ranging from the permitting of new power plants to the setting of electricity rates.

CCS technology. Although the vast majority of natural gas SCGT units would not be subject to the rule, few of them would meet the target. However, demand for SCGT units is expected to rise with the increased deployment of renewables (e.g., wind- or solar-generated electricity). This is because the way in which SCGT units are designed to meet peaks in demand allows them to efficiently smooth the often intermittent generation from renewables (Lamont 2008). This complementary relationship between renewables and SCGT units raises important questions about how the effective exemption of SCGT units from the standard may be a missed opportunity. In particular, greater demand for renewables will mean greater demand for new, unregulated SCGT units, which could lessen the efficacy of renewables to reduce emissions.

It is clear that the proposed emission targets are designed primarily for the more efficient natural gas CCGT units, which are the current trend in new EGUs for baseload generation. Among the recently constructed CCGT units, we found lower emission rates for those with larger generation capacity and utilization rates. This explains, at least in part, why the EPA moved from a single standard in the originalCPS to two standards for natural gas units (depending on capacity) in the revisedCPS. We find that the vast majority—greater than 90 percent—of recently constructed CCGT units would already comply with the proposed emission standard for new EGUs.

It is important to emphasize that our analysis of the emission rates of existing EGUs is based on the way that *current* technology is utilized. Thus any future changes in electricity generation technologies reduce the predictive usefulness of our analysis. Nevertheless, we believe our approach provides information that is helpful for understanding the potential implications of implementing the proposed standards for new power plants. Looking at existing EGUs might also be useful for understanding the implications of subjecting existing units to the rules if they make modifications that qualified them for New Source Review (see, e.g., Bushnell and Wolfram 2006; Keohane, Mansur, and Voynov 2009), and uncertainty about how New Source Review would be applied to the proposed standards has been a subject of concern (Burtraw et al. 2012).

We also want to emphasize that our analysis does not consider the economic costs, benefits, and overall efficiency of the proposed rule. Indeed, quantitatively addressing these issues would require data and analysis beyond the scope of this article. Thus we leave such analyses to future research.[20] We can, however, make some final observations concerning the instrument choice of the proposed standards. Because the proposed regulation is a performance-based standard specific to each power plant, it is likely to have higher costs of compliance than an alternative policy for a given level of aggregate abatement. The obvious alternative policies are the first-best market-based policies such as a carbon tax or cap-and-trade regulation; however, in practice, these policies have failed to pass at the national level in the United States. The proposed rules may also have some unintended consequences. In particular, as with many vintage differentiated regulations that distinguish between new and old units, the proposed standards are likely to distort the retirement decisions of existing plants (Gruenspecht 1982).

[20]However, the EPA's Regulatory Impact Analysis reports (EPA 2012b, 2013b) are important first steps in this direction.

Appendix Table 1 Average fuel cost for electric utilities (prices reported in $/mmBtu)

State	Natural gas price	Coal price	Ratio
SC	$4.77	$3.69	1.3
GA	$4.98	$3.68	1.4
NY	$5.51	$3.77	1.5
NH	$5.66	$3.80	1.5
MS	$4.82	$3.17	1.5
VA	$5.56	$3.29	1.7
AL	$4.74	$2.72	1.7
NC	$6.49	$3.54	1.8
FL	$6.51	$3.45	1.9
TN	$4.94	$2.58	1.9
WV	$4.88	$2.49	2.0
LA	$4.68	$2.38	2.0
OH	$4.84	$2.11	2.3
IN	$4.90	$2.10	2.3
NM	$4.85	$2.03	2.4
TX	$4.57	$1.87	2.4
NV	$5.94	$2.42	2.5
UT	$4.29	$1.71	2.5
KY	$5.82	$2.25	2.6
WI	$5.56	$2.07	2.7
OR	$4.50	$1.66	2.7
OK	$4.72	$1.71	2.8
SD	$5.49	$1.95	2.8
MI	$5.80	$2.01	2.9
IL	$5.68	$1.94	2.9
AZ	$5.33	$1.80	3.0
CO	$4.99	$1.54	3.2
KS	$4.98	$1.51	3.3
MO	$5.17	$1.56	3.3
MN	$5.98	$1.75	3.4
AR	$6.20	$1.71	3.6
MT	$5.25	$1.41	3.7
IA	$5.64	$1.33	4.2
WY	$6.03	$1.26	4.8
NE	$7.16	$1.42	5.1
ND	$7.95	$1.25	6.4

Notes: Only states purchasing both fuels are listed.
Source: Data from EIA form 923 for 2010.

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