Are we Fracked? The impact of falling gas prices and the implications for coal-to-gas switching and carbon emissions

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Abstract

We discuss the environmental implications of the dramatic drop in the price of natural gas following the US shale gas boom due to the rise of modern hydraulic fracturing. In the first part of the paper, we argue that the ensued drop in the price of natural gas has an ambiguous effect on global carbon emissions because of three countervailing effects: coal-to-gas switching in the US electric power sector, an increase in the relative cost of US renewable energy sources, and an increase in US coal exports. Our position is that without a meaningful cap, the shale gas boom is likely to increase global emissions and the period during which natural gas is used as a bridge fuel to clean energy should be limited. In the second part of the paper, we review recent environmental policies for the US electric power sector that have contributed in reducing carbon emissions, and discuss the complex economics of the newly introduced Clean Power Plan. Although the availability of cheap natural gas has been factored in US environmental policy and has helped electricity generators to achieve compliance with various rules and regulations, it should not derail policy from its long run objective, which is the transition to a less fossil-fuel dependent economy.

Key words: shale gas, fuel switching, emissions, environmental policy, Clean Power Plan.

JEL classification: L94, Q42, Q48, Q58.

I Introduction

Between 2005 and 2013, carbon dioxide (CO_2) emissions from fossil-fuel combustion in the US electric power sector—the largest source of CO_2 emissions in the country—fell by 15%. The slowdown of the economy due to the Great recession can explain a part of this decrease. There are

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also state and federal policies that have been promoting the decarbonization of the US electricity sector for several years. During the same period, the share of natural gas in electricity generation increased from 17% to 28%, while that of coal dropped from 51% to 39%. The coal-to-gas switching observed in electricity generation has been attributed to a large extent to the introduction of hydraulic fracturing, or fracking, which has led to a dramatic reduction in the price of natural gas.[2]

Fracking differs considerably from traditional drilling for natural gas and oil. Geologists have long known that oil and natural gas exist in shale formations. However, within shale formations, the hydrocarbons rest in small pockets of the rock rather than large underground pools as with traditional oil and natural gas resources. The secret to extracting these resources is to combine the vertical drilling of a traditional well with both a horizontal section and pumping water down through the well to break up small pockets within the rock where the hydrocarbons lie. This fracturing of the shale rock then allows the hydrocarbons to escape up through the well. The first well was fracked in this fashion by Mitchell Energy and Development in the Barnett Shale basin in 1998. Large scale use of the technique, however, began in 2005.

Largely due to fracking, US gross withdrawals from shale gas wells have outpaced withdrawals from conventional sources in a spectacular manner since 2007 (Figure 2, panel(a)). The production in the Marcellus basin, which has experienced a tremendous growth in fracking activity, increased from 1.14 million Mcf/day in January 2007 to 16.5 Mcf/day in August 2015. In addition, according to Baker Hughes, between 2009 and 2014, the number of horizontal rigs skyrocketed.[3] Overall, the US production of dry natural gas increased at an annual rate of around 3.5 percent during 2005–2013. In contrast, dry natural gas production in Europe *decreased* at an annual rate of about 1.5 percent, while Russian production increased by only 0.5 percent per year during the same time.[4] In 2013, the US was the largest producer of natural gas in the world with a dry natural gas production of just over 24 trillion cubic feet with Russia trailing at around 22 trillion. Note also that large amounts of oil are also produced from fracking—in 2014, the US was the largest producer of crude oil, natural gas petroleum liquids, and other liquids, at about 14 million barrels per day leaving Saudi Arabia second at about 11.6 million barrels.[5]

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[2] See http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html for carbon dioxide emissions. See net generation from electricity plants in http://www.eia.gov/electricity/data/browser/ for generation.

[3] See historical data on North America Rig Count from Baker Hughes available at http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother.

[4] See the section on Natural Gas from the EIA International Energy Statistics at http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm.

[5] The international comparisons regarding natural gas and oil are based on EIA International Energy Statistics available at http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm. Some commentators have suggested that the North American shale boom and its effect on the production of both gas and oil has triggered reactions from countries dominating the international energy markets for many years seeking to protect their interests. There have been suggestions in the media that the recent dramatic drop in the price of crude oil was caused by Saudi

The increase in hydrocarbon production from shale formations in the US has had an impact on both natural gas and oil prices. However, the impact on natural gas prices has been much larger because natural gas markets are much more localized than oil markets given the high transportation cost of natural gas in liquefied form. As panel (b) of Figure 2 illustrates, there is essentially a North American, a European, and an Asian market for natural gas, and more so after 2010, with the latter two being subject to a premium.[6] In June of 2008, the price of natural gas for the US electric power sector was \$12.4/Mcf. By April 2012, the sector was paying \$2.8/Mcf (Figure 2, panel(c)). When expressed on a per-MWh basis, gas prices were at parity with spot eastern coal prices by early 2012 (Figure 2, panel(d)).[7]

Based on the observations above, understanding the income and substitution effects of the reduction in the price of natural gas for the US economy is important for policy. The income or scale effect is related to the overall increase in energy consumption. The substitution effect stems from the fact that natural gas is a substitute for other energy sources, which are both more and less carbon-intensive, in various sectors of the economy. Natural gas is a substitute for coal and oil, as well as for nuclear and renewable sources—wind and solar—in the electric power sector. It is also a substitute for gasoline and diesel oil in the transportation sector, and a substitute for electricity in the residential and commercial sectors. Annually, natural gas expenditures have accounted for roughly between 0.9% and 1.7% of US GDP during 2000–2012.[8] Therefore, it is rather unlikely that lower natural gas prices will have a notable income effect in the economy overall. We discuss the substitution effects focusing on the electric power sector later in the paper. The substitution effects in other sectors of the economy are beyond the scope of this paper and can be found elsewhere (Newell and Raimi (2014)).

The effect of the increase in natural gas production on global CO_2 emissions is ambiguous because of three countervailing forces. First, the reduction in the price of natural gas leads to an increase in the price of coal relative to the price of gas all else equal in the US. Hence, we expect

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Arabia in an effort to make fracking in North America uneconomic in what has been described in a rather colorful manner as "Sheikhs v Shale." For example, Economist (2014) writes: *"Saudi Arabia, the leading member of OPEC, has made it clear that it will tolerate lower prices in order to do to shale firms' finances what fracking does to rocks."*

[6] US natural gas producers are largely separated from the international markets outside North America due to the limited infrastructure to ship natural gas in liquefied form. Between 2005 and 2014, the US has exported, on average, 5.3% of its annual dry production with pipeline exports accounting for about 96% of total exports; see `http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm` and `http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=26&aid=1`. Due to the difficulty of inter-continental transportation of natural gas, the world markets are not well integrated—see, for example, Li et al. (2014).

[7] See average cost of fossil fuels for electricity generation for all sectors, monthly in `http://www.eia.gov/electricity/data/browser/`. The regional coal prices are from SNL Energy. We assume a heat rate of 7,500 Btu/KWh for combined-cycle electric generating units (EGUs). Annual heat rates for steam coal EGUs are available from EIA at `http://www.eia.gov/electricity/annual/html/epa_08_02.html`.

[8] Our calculations are based on data from EIA (2015c).

US electricity generators to switch from coal to natural gas—this response is well documented in numerous studies, the media, and the academic literature we discuss below. The immediate implication is a drop in CO_2 emissions in the US.

The drop in natural gas prices also makes electricity generation from renewable sources relatively more expensive in the US. This increases CO_2 emissions because renewable sources produce essentially zero emissions. Shearer et al. (2014) find that abundant natural gas decreases use of both coal and renewable energy technologies in the future across a range of climate policies in the US. Investment in renewables is also sensitive to natural gas prices. For example, lower natural gas prices in the *High Oil and Gas Resources* scenario in EIA (2015a) result in fewer renewable capacity additions toward the end of the projection period (2040) and lower generation compared with the *Reference* case.

Finally, the downward pressure on the price of US coal due to lower domestic demand coupled with the inability of the US to export cheap natural gas in large scale in the immediate future, make US coal an attractive option for coal-importing countries leading to an increase in US coal exports. This will tend to increase CO_2 emissions, this time outside the US.[9] Hence, it is important to take into account the implied carbon "leakage" in any discussion about the implications of increased US shale gas production for global emissions.

The remainder of the paper is organized as follows. Section II offers an economist's understanding of hydraulic fracturing. Section III provides an analysis of the implications of increased natural gas production for carbon emissions through the lens of the three countervailing effects identified above. In Section IV, we discuss recent developments in US environmental policy with regard to the electric power sector and discuss the economics of the newly adopted Clean Power Plan. All tables and figures are provided after the main text.

II Hydraulic Fracturing

Modern-day fracking techniques began in the 1980s, when George Mitchell of Chesapeake Energy began experimenting with different techniques in the Barnett Shale in Texas. His innovation was two-fold: pumping water into wells at much larger volumes and pressures than before and adding a combination of chemicals and sand to the water. By the late 1990s, the Barnett Shale basin began

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[9] This will be the case if US coal increases global energy consumption (scale effect) and/or displaces less-carbon intensive sources of energy (substitution effect). However, it could be the case that the scale effect is very small (or even zero) and the US coal displaces dirtier coal. In this case, global emissions will fall. Therefore, it is possible to reduce carbon emissions by exporting coal; see `https://energy.stanford.edu/news/reduce-greenhouse-gas-exporting-coal-says-frank-wolak`.

producing oil at previously unheard of rates, but another innovation was about to occur. In the early 2000s, Mitchell combined the massive "slick-water" fracking with a horizontal section of the well. The horizontal section increased the amount of well area within the shale rock formation—modern-day fracking had arrived.

Fracking soon started to spread to other shale formations. The US currently has over 10 active shale plays, regions of shale formations targeted by oil and gas producing companies, generally exhibiting similar geological and drilling characteristics. The shale deposits stretch from the west coast to the Appalachian mountains. The industry has found that applying the technique to other shale deposits is not straightforward. Although the broad approach is similar, the types and number of fracking stages, chemicals, and amount of sand used vary significantly across different shale formations. The early experience in the Marcellus basin differed dramatically from Mitchell's experience in the Barnett basin. In addition, basins vary considerably as to whether they produce oil or natural gas. For example, over 90 percent of the hydrocarbons coming out of the Bakken basin are oil, while over 90 percent of the hydrocarbons coming out of the Marcellus basin are natural gas.

Conventional drilling involves drilling into the earth looking for pools of hydrocarbons. Once the drill bit reaches the pool, usually 1,000–5,000 feet below the surface for an on-shore well, it is removed, and a casing pipe is placed into the hole. For shale-based wells, drilling continues to much larger depths, often exceeding 10,000 feet and, generally, significantly below the water table. Once the bit nears the shale formation, the bit begins to turn sideways. Drilling then continues in a horizontal fashion, often for longer than 10,000 feet. Because of the increased depth and number of steps, fracked wells are more expensive than conventional wells. A typical conventional well requires an investment of roughly \$1 to \$3 million to determine whether the resources below the ground can be recovered. A hydraulically fracked well costs roughly \$5 to \$8 million.[10]

Unconventional gas (tight, shale, coalbed methane (CBM)) in North America is economically viable at prices of \$3 to \$4/Mcf (Aguilera (2014)). The costs of producing unconventional gas can be both lower and higher than those of conventional gas, with the higher-cost sources of unconventional gas being economically viable at prices of at least \$20/Mcf. According to IEA (2013), conventional natural gas sources have typical production cost between \$0.20/MMBtu and \$9/MMBtu. Sour gas resources, which have high concentrations of hydrogen sulfide, could be produced at costs between \$2 and \$11/MMBtu. The production cost for resources in the Arctic Circle are between \$4 and \$12/MMBtu, and those for deep water resources are between \$5 and \$11/MMBtu. Finally, the production cost for unconventional gas (tight, shale, and CBM) range

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[10] See, for example, `https://blogs.siemens.com/measuringsuccess/stories/688/`.

between \$3 and \$10/MMBtu.[11]

The almost exponential increase of production in the Marcellus and Bakken basins between 2007 and 2012 is consistent with gas production that was largely profitable for prices in the ranges discussed above. The dramatic increase in fracking activity led to an unprecedented decrease in the price of natural gas changing fundamentally the landscape of the US electric power sector via coal-to-gas switching. In what follows, we focus on how the shale boom affected the mix of coal- and gas-fired generation in the US and its impact on global CO_2 emissions.

III Implications for Carbon Emissions

There is an ongoing debate about the economic and environmental effects of fracking in the US. Hausman and Kellogg (2015) argue that the climate change impacts have been large, but they do not outweigh the private gains. According to their estimates, the shale boom generated net economic benefits, not including environmental impacts, of \$48 billion in 2013, or about a third of 1 percent of the US GDP. They also show that plausible bounds on the greenhouse gas costs from shale gas for 2013 are \$3–\$28 billion.[12]

We argue that fracking has an ambiguous effect on global CO_2 emissions due to three countervailing effects. First, the reduction in the price of natural gas leads to an increase in the price of coal relative to the price of gas in the US, all else equal. Hence, we expect US electricity generators to switch from coal to natural gas. Since coal generates roughly two times the CO_2 emissions as natural gas per MMBtu, we would expect a drop in CO_2 emissions in the US.

The two remaining effects increase emissions. The drop in natural gas prices makes electricity generation from renewable sources relatively more expensive in the US. The implication is an increase in emissions because renewables are essentially CO_2 free. Finally, the downward pressure on the price of US coal due to lower domestic demand coupled with the inability of the US to export cheap natural gas in large scale in the immediate future, make US an attractive option for

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[11] See Figure 8.4 and the discussion on pages 231–232 of the IEA report. For comparison with the costs reported in Aguilera, keep in mind that 1 Mcf of natural gas contains approximately 1 MMBtu of energy. It is important to note here that the cost curve in figure 4 is static and does not take into account the effect of learning by doing, an important aspect of the drilling activity; see Covert (2014) and Redlinger (2015). Redlinger investigates not only learning by doing, but also organizational forgetting, as well as learning spillovers.

[12] Bartik et al. (2015), Newell and Raimi (2015), CBO (2014), and Muehlenbachs et al. (2014), all examine the effect of the shale gas boom on the economy with diverse topics, such as crime, public finance, and housing values, to name a few examples. The Shale Public Finance project at Duke University seeks to identify the key public finance issues facing local governments that are dealing with the shale boom; see `http://energy.duke.edu/shalepublicfinance`. The impact of the fall in the price of natural gas on electricity prices depends on the frequency that natural gas plans are marginal in the merit order, which varies by time and region. Linn et al. (2014) find larger impacts of natural gas price for on-peak wholesale electricity prices.

coal-importing countries, which leads to an increase of US coal exports. This last effect will also tend to increase CO_2 emissions. However, the increase in CO_2 emissions will take place outside the US. In the next section, we discuss each of the three countervailing effects further.[13]

Before discussing the three effects in detail, it is important to emphasize that without a meaningful cap on global carbon emissions, the shale gas boom is likely to increase global emissions. Consumption of displaced fossil fuels must be reduced globally and remain suppressed in the future—essentially, displaced coal must stay in the ground. Our position is fully aligned with that of Aghion et al. (2014), who argue that the transition from coal to clean energy using bridge fuels, such as natural gas, should be for a limited period of time, and the appropriate policies should be in place to avoid what the authors term "gas lock-in."

III.1 US Coal Displacement

In this section, we document coal displacement by natural gas in the US electric power sector both in the short and the long run. We also discuss the implications of coal-to-gas switching in terms of emissions.

Starting with the short-run displacement, between 2003 and 2012, the consumption of coal fell from about 20.8 to 16.3 million MMBtu, a decrease of roughly 22%. During the same period, the consumption of natural gas increased from about 6.5 to 10.6 million MMBtu, a stunning 63%. Looking at net generation (MWh), the numbers are even more telling: 23% decrease for coal, and almost 90% increase for natural gas during the same period. In 2003, coal and gas accounted for 51% and 17% of total generation, respectively. In 2012, coal accounted for only 37%, while natural gas accounted for 30%.[14]

The share of natural gas—out of coal plus natural gas only—in fuel consumption (MMBtu) exhibited a clear upward trend for 2003–2012, which was slightly reversed in 2013. It increased from about 25% to around 40%, respectively. The share of natural gas in net generation (MWh) exhibited a similar increase. In April 2012, gas-fired generation exceeded coal-fired generation for

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[13] Note that we exclude from our discussion methane (CH_4) emissions at different stages along the supply chain—so-called methane leakage. These emissions are important as methane has a global warming potential is that is higher than that of $C0_2$ and there still remains a high degree of uncertainty as to their level. Table ES-2 from the EPA GHG inventory shows that natural gas systems accounted for about of 26 percent of total CH_4 emissions (CO_{2e}) per annum between 1990 and 2011 in the US; see `http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html#fullreport`. See Balcombe et al. (2015) for a comprehensive review of over 250 studies and reports on methane emissions.

[14] The numbers discussed here pertain to the US electric power sector as defined by the EIA: electric utilities and independent power producers. The numbers related to fuel consumption and net generation are from EIA (2015b).

the first time since EIA collects data.[15] The capacity factor for gas-fired combined-cycle electric generating units (EGUs) was at parity with that for coal in March 2012, and exceeded slightly that for coal in April 2013 (panel (a), Figure 3). Panel (b) of figure 3 provides some explanation for these facts using marginal costs across gas-fired plants in the US for 2008–2012, constructed with data from SNL Energy. As we transition from 2008 (light gray curve) to 2012 (black curve), natural gas becomes increasingly more competitive as an energy source for electricity generation.

Dark and spark spreads provide additional support for the fact that gas-fired power generation has become increasingly more competitive. Using data from EIA on wholesale electricity prices and rail transportation rates, we calculated monthly spark and dark spreads for Pennsylvania New Jersey Maryland Interconnection (PJM), the largest wholesale electricity market in the US. In 2008, the average monthly dark spreads for coal from Central Appalachia and the Powder River Basin were $15/MWh and $50/Mwh, respectively. By 2011, the same averages were down to about $1.3/MWh and $23/MWh. During the same period, the average monthly spark spread increased from $2.1/MWh to $13.5/MWh.[16]

Short-run coal displacement in US electricity generation by natural gas due to the falling natural gas prices is also documented in the academic literature. In Knittel et al. (2015) we find that the response of electricity generators to falling natural gas prices was heterogeneous. In particular, we find that investor-owned utilities (IOUs) operating in traditional vertically-integrated markets that did not restructure in the late 1990s and early 2000s are more sensitive to changes in fuel prices than both IOUs and independent power producers (IPPs) in restructured markets. We attribute our findings to differences in available gas-fired generating capacity: the entities of interest reduced their rate of investment in the restructured markets post restructuring. Fell and Kaffine (2014) show that low natural gas prices and increased wind-powered generation have both led to reductions in coal-fired generation. The interaction between natural gas prices and wind-powered generation led to a greater reduction in coal-fired generation than would be explained by either factor alone. Holladay and LaRiviere (2014) find that gas-fired generation has displaced coal-fired generation as the marginal fuel source even during base load hours.[17]

There are also long run effects. Table 1 shows coal-fired plant retirements for 2010–2035 in 9 scenarios of EIA (2011). Retirements in the different cases vary between 9 and 135 GW depending on the stringency of environmental rules, the assumed cost-recovery period for retrofit investments,

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[15] See `http://www.eia.gov/todayinenergy/detail.cfm?id=6990`.

[16] We use the EIA formulae for the dark and spark spreads: dark spread ($/MWh) = power price ($/MWh)- [coal cost ($/ton) + transport cost ($/ton)] × heat rate (MMBtu/MWh) / heat content (MMBtu/ton); spark spread ($/MWh) = power price ($/MWh) - [natural gas price ($/MMBtu) × heat rate (MMBtu/MWh)]. The details of the calculations are available from the authors upon request.

[17] See also Linn et al. (2014).

natural gas price levels, and assumptions regarding future greenhouse gas (GHG) regulations. As expected, the at-risk plants are older and less efficient.[18] To view the long-run coal displacement from a different angle, it is useful to compare the competitiveness of coal- and gas-fired generation using the levelized cost of electricity (LCOE), which measures the real life-cycle cost per MWh of building and operating a generating plant.[19] For plants coming on line in 2019, the average LCOE in 2012 dollars per MWh is 95.6 for conventional coal, 66.3 for conventional combined-cycle, and 64.5 for advanced combined cycle gas-fired plants (EIA (2014b)).

The implications for emissions of the changing landscape described so far have been significant. Figure 4 shows annual CO_2, nitrogen oxides (NO_x), and sulfur dioxide (SO_2) emissions for EGUs in the Environmental Protection Agency (EPA) Continuous Emissions Monitoring System (CEMS) database between 2003 and 2013 for utilities only. During this period, CO_2 emissions decreased from about 2,400 million short tons in 2003 to roughly 2,100 million short tons in 2012, a 12.5% decrease. The big dip in 2009 is due to the recession and it disappears if one accounts for electricity generation. For the same 10-year window, we see an almost 60% decrease in NO_x emissions, and a decrease of around 70% in SO_2 emissions. Of course, we should not discount the effect of the Renewable Portfolio Standards in the deployment of renewable sources, which should also account for some of the reduction in emissions discussed here.

Numerous papers have also investigated the relationship between natural gas prices and emissions. Brehm (2015) finds that carbon emissions in 2013 fell by approximately 15,000 tons/hour due to coal-to-gas switching induced by lower natural gas prices. He also finds that more efficient gas-fired capacity led to an additional decrease in carbon emissions of 2,100 tons/hour in 2013. According to the author's estimates, 65–85% of this new capacity was due to lower gas prices. Using a social cost of carbon of \$35/ton, he values the social benefit of reduced carbon emissions at roughly \$5.1 billion. In Knittel et al. (2015), we find that the almost 70% drop in the price of natural gas paid by the entities in our sample between June 2008 and the end of 2012 translates to as much as 33% reduction in CO_2 emissions for IOUs in traditional vertically integrated markets, but only up to 19% for IOUs in restructured markets.

Cullen and Mansur (2014) show that both carbon and cheap natural gas can reduce the cost advantage of coal-fired plants in a very similar way. Based on their estimates, a carbon price of

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[18] In the Reference case of EIA (2012), 49 GW of coal-fired capacity are retired through 2035. In the Reference case of EIA (2014a), about 60 GW of coal-fired capacity are projected to retire. See Niven and Gilbert (2011) for the demographics of coal-plant retirement announcements for 2011–2020. BPC (2011) offers a summary of studies conducted in 2010–2011 to assess the potential magnitude of coal-fired unit retirements with ranges roughly between 15 and 70 GW depending on the regulations considered—see Table 3 on page 22 of the report.

[19] Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance costs, financing costs, and an assumed utilization rate. For an informative exposition, including an LCOE formula, see `http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf`.

$10/ton would reduce emissions by 4%, and a carbon price of $60/ton is needed to cut emissions by 10%. Carbon prices are much more effective at reducing emissions when natural gas prices are low.[20] If fuel prices evolve according to industry forecasts, the authors predict a 6% decrease in CO_2 emissions from a $20/ton price on carbon, but if gas prices were to return to their typical, pre-shale-gas levels, the same carbon price would reduce emissions only by 1%.[21]

Overall, there is strong evidence that abundant cheap natural gas has contributed to a decrease in carbon and criteria pollutant emissions in the US. However, we cannot discount the role of state and federal environmental policies that have been in place for several years and have been proved to be effective in reducing emissions. A large number of such policies have focused on promoting electricity generation of renewable resources, which is the topic of our next section.

III.2 US Renewable Sources

Our understanding of how the dramatic drop in natural gas prices has impacted renewable energy penetration is less clear, especially in the absence of a formal econometric analysis. What is clear, however, is that renewable energy penetration in the US has increased dramatically with both government and private-sector R&D propelling the progress. At the same time, numerous federal and state programs promoting renewable sources have been in place and we discuss them in detail in Section IV.

The existing net summer generating capacity associated with renewable sources has increased from about 18 GW to roughly 83 GW between 2003 and 2013 (EIA (2015b)). Solar and wind power are the leaders experiencing 9-fold and 16-fold increases, respectively. In 2014, there were approximately 66 GW of wind power capacity in the US with 14 GW just in Texas.[22] In the same year, California installed close to 4 GW of solar photovoltaic (PV) capacity, which is more than what the entire country installed between 1970 and 2011.[23]

This increase in renewable energy penetration is a function of decreases in the long-run average cost of both solar photovoltaic (PV) and wind generation combined with regulatory incentives discussed in the next section. Solar PV cell prices have dropped by a factor of 100 over the last 35 years, and by a factor of more than 10 the last 15 years. The median reported price for in-

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[20] The increase in carbon emissions from raising the natural gas price by $1 is highest when natural gas prices are low because coal and natural gas have similar marginal costs when gas is relatively inexpensive.

[21] Lu et al. (2012) find that between 2008 and 2009, carbon emissions fell by almost 9% in the US electric power sector, 4% of which was due to falling natural gas prices. A carbon price of $20/ton reduces annual emissions from the electricity sector by 7%.

[22] `http://apps2.eere.energy.gov/wind/windexchange/wind_installed_capacity.asp`

[23] See `http://www.seia.org/research-resources/2014-top-10-solar-states`.

stalled residential and commercial PV systems was $10/MW (2013$) in 2002 and about $4/MW in 2013.[24] Wind turbines have become taller with longer blades that allow them to operate in lower wind conditions and access stronger consistent winds. They are also cheaper to build. Plants powered by solar and wind energy are more economical than gas-fired plants in terms of their variable costs, which are essentially zero. With that being said, although wind- and solar-powered generation could displace gas-fired generation once the associated capacity has been built, it is important to keep in mind that both solar and wind are intermittent resources. As for the competitiveness of renewable sources in terms of their LCOE, the LCOE for onshore (offshore) wind turbines is $80/MWh ($204/MWh) in 2012 dollars, while that for PV and thermal solar is $119/MWh and $224/MWh, respectively (EIA (2014a)).

Lower natural gas prices have both a direct and indirect effect on renewable energy penetration. The direct effect is that lower natural gas prices imply cheaper electricity prices, making renewable sources less attractive. For example, a $1/MMBtu decrease in natural gas prices decreases the marginal cost of a combined-cycle gas turbine (CCGT) plant by roughly $7.5/MWh.[25] The effect on wholesale electricity prices will depend on which plants are marginal. At current prices, CCGTs increasingly serve more base load demand suggesting the effect on off-peak prices can be of similar magnitude. During peak periods, less efficient gas turbines are often the marginal units setting the market clearing prices, implying the effect on electricity prices from a given drop in natural gas prices can be even larger.[26]

Cheaper natural gas prices may have an indirect effect on renewable sources as well. As natural gas prices fall and coal gives way to gas-fired generation, policy makers may find it more difficult to mandate generation from renewable sources since carbon emissions will be falling in the absence of such a mandate.[27]

III.3 US Coal Exports

The decrease in the domestic demand for US coal, largely due to the collapse of natural gas prices, implies a movement along the US coal supply curve leading to a lower price that makes US coal

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[24] See `http://www.nrel.gov/docs/fy14osti/62558.pdf`.

[25] This is because the heat rate of a typical CCGT is 7,500 Btu/KWh.

[26] If a technology other than natural gas is the one setting the market clearing price, then a reduction in natural gas prices will not affect wholesale electricity prices.

[27] It is also possible to argue that renewable sources and natural gas are complements given that wind and solar sources are intermittent—i.e., their production increases and decreases with changes in weather and sunlight patterns. Given this intermittency, natural gas plants often act as back up generation. However, the effect of changes in natural gas prices on the long-run average cost of back up generation will necessarily be smaller than the effect on the long-run average cost of natural gas generation that runs in more hours assuming the same heat rate.

more attractive to other markets. Not surprisingly, the US has experienced a large increase in coal exports since 2006 with steam coal being the main driver (panel (a), Figure 5). Total (steam plus metallurgical) US coal exports increased by a factor larger than 3 between 2002 and 2012, from 39.6 to 125.7 million short tons. The US was exporting roughly 5% of its total coal production between 2000 and 2006, while by 2012, the fraction of production exported jumped to 14% with the rest of the world exporting somewhere between 16% and 18% of its total production.

The exports of major coal-producing countries with the exception of South Africa were growing during 2002–2012, which means that the increase of US coal exports did not come at their expense (panel (b), Figure 5). During the same period, the US share of world exports increased from 5% to 9%, while that of Australia oscillated between 25% and 30%. Indonesia's share increased by a factor of about 3 reaching 30% by 2012. Hence, although the role of the US in international coal trade has increased, it is still not as prominent as that of Australia and Indonesia. The increase in US exports of steam coal to the Netherlands, the UK, and France, was more than 3-fold between 2010 and 2012. US exports of steam coal to China were 158 thousand short tons in 2009 and almost 3.2 million in 2012. Exports of steam coal to Japan increased from 192 thousand short tons in 2010 to about 1.4 million in 2013. For India, the increase in US steam coal exports was also dramatic—from around 2 thousand short tons in 2009 to about 2 million in 2012.[28] Over the past two years, coal exports have subsided. Much of this decrease is due to a drastic drop in exports to China due, most likely, to a weakening of the Chinese economy. Not surprisingly, over this time period we also see an increase in the coal share of electricity generation in the US.

In an attempt to measure the extent to which the increase in US coal exports is due to the drop in domestic natural gas prices, we performed the following simple exercises, which need a cautious interpretation. Between 2008 and 2012, the Henry Hub spot price for natural gas fell by almost 70%, while US exports of steam coal increased roughly by 43%. Attributing the entire increase in steam coal exports to the decrease in domestic prices for natural gas would imply an elasticity of about -0.6. A simple regression of US steam coal exports on US natural gas prices paid by electricity generators also suggests a relationship between the two. Using quarterly data for 2002–2014, a 10 percent *decrease* in US natural gas prices is associated with a 3.3 percent increase in US coal exports, implying an elasticity of -0.33. With these elasticity estimates in hand, it is possible to translate the drop in the price of natural gas to US exports of CO_2 emissions.

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[28] There is plenty of evidence that the world market for steam coal is integrated (Li et al. (2010)). According to IEA (2014), the US was competing head to head with other major coal producing regions for the European market of steam coal in terms of prices between 2000 and 2010. International coal trade is dominated by sea transport, which accounts for about 90% of the global coal turnover for 2000–2013 based on annual figures from the IEA Coal Information 2012 (see Table 3.1). Schernikau (2010) offers a very informative discussion of the economics of the international coal trade.

Translating the increase in US coal exports to an increase in global emissions on the basis of simple calculations like the ones just described would require strong assumptions that can lead to false conclusions. For example, one would need to make an assumption regarding whether the increase in US exports is less than or equal to the increase in demand for coal at a destination country. It could very well be the case that incremental US exports simply displace say Australian or Indonesian exports, or even domestic production, of potentially dirtier coal, with the demand at the destination country remaining the same.

Neither of the two simple exercises, takes into account two key factors: the increase in global demand and how much of that increase will be served by non-US coal producers. Setting aside the vast energy needs of China and India, a series of events have also contributed to an increase in the demand for coal worldwide, which has contributed to the increase in US coal exports. The EU Emissions Trading System essentially collapsed by early 2006. The Arab Spring began in December 2010 in Tunisia disrupting the EU natural gas markets that have historically relied to gas originating in Africa (e.g., Algeria, Egypt, Nigeria). Japanese demand for coal and natural gas increased in March of 2011 due to the Fukushima nuclear accident. In May 2012, Germany announced that it would retire all its nuclear capacity by 2022 increasing Germany's demand for alternative sources of energy. In early 2014, Russia invaded Ukraine, the main corridor of Russian natural gas to the EU market.

Estimating the fraction of the increase in global demand for coal served by non-US producers is not a straightforward exercise because it requires a reliable estimate of the export supply elasticity for such producers and is the subject of a research agenda we are currently pursuing.

IV US Environmental Policy

In this section, we review the status of federal and state-level environmental policies that have been shown to be effective at mitigating carbon and criteria pollutant emissions. Several of these policies have promoted the use of renewable sources in electricity generation as documented in the previous section, and we argued that they could be compromised by the abundance of cheap natural gas that makes energy from renewable sources more expensive. We also discuss the economics of the most important development in environmental regulation, the Clean Power Plan, in which the abundance of cheap natural gas has played an important role.

IV.1 Federal and State Policies

Concurrent with the reduction in coal-fired generation in the US and the corresponding increase in gas-fired generation resulting from the change in the relative price of the two fuels, there have been a number of environmental regulations affecting the US electricity sector. To begin with, a series of EPA laws and regulations regarding air, waste, and water have been introduced. In December 2011, the EPA announced Mercury and Air Toxics Standards (MATS) for power plants. EPA has also taken actions to facilitate the implementation of the CAA "good neighbor" provision, including administering the NO_x Budget Trading Program, the Clean Air Interstate Rule (CAIR), and the Cross-State Air Pollution Rule (CSAPR). Due to the increased use of natural gas for electricity generation in the aftermath of the shale boom compliance with these rules and regulations is in principle easier given that natural gas is a cleaner fuel than coal across multiple dimensions.

Furthermore, there is a plethora of federal and state policies promoting renewable sources. State-level policies take two forms: renewable portfolio standards (RPSs) and net metering. Renewable portfolio standards, also known as renewable electricity standards (RESs), are mandatory requirements for retail electricity suppliers to supply a minimum percentage or amount of their retail electricity load with electricity generated from eligible renewable sources. As of June 2013, 29 states and the District of Columbia have adopted mandatory RPSs and 9 more states have voluntary renewable goals. The RPS requirements typically start at modest levels and ramp up over a period of several years.

Retail electricity suppliers can comply with RPS requirements through several mechanisms, which vary by state, including ownership of a qualifying renewable energy facility and its electric generation output, purchasing electricity bundled with renewable energy certificates (RECs) from a qualifying renewable energy facility, and purchasing RECs separately from electricity generators.[29]

These compliance mechanisms create subsidies, either directly or indirectly, for renewable energy. For electricity generators, the effect of RPS compliance using their own resources is similar to that of "performance standards", such as fuel economy standards and low carbon fuel economy standards. Under the RPSs, EGUs internally subsidize renewables as they loosen the REC constraint, while internally taxing non-renewables since more non-renewable generation requires the EGUs to increase renewable generation in order to comply with the RECs. RECs, on the other hand, provide a direct subsidy. Generation from renewables sources generate RECs that can then

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[29] See Schmalensee (2013) for a study of the growth in wind and solar generation due to government subsidies. Cullen (2013) in his analysis of wind electric power in ERCOT shows that— accounting for dynamics in the production process—the value of emissions offset by wind power exceed the cost of renewable energy subsidies only when the social costs of carbon is above $42/ton.

be sold to other non-compliant EGUs generating additional revenues for their owners.

In addition, the federal Production Tax Credit (PTC) offers a financial incentive in the form of a corporate tax credit to the commercial and industrial sectors for generation using renewable energy sources but it does not include solar power. The incentive amount is $0.023/KWh for wind generation and it generally applies to the first 10 years of operation. Unused credits may be carried forward for up to 20 years following the year they were generated or carried back 1 year if the taxpayer files an amended return.[30]

Finally, electricity consumers have been participating in net-metering programs in growing numbers since 2003, which is the first year EIA reported data for these programs. Between 2003 and 2010, the average annual growth in customer participation was 56%, with a 61% increase between 2009 and 2010. Despite the increase, customers with net metering represented only 0.1% of all customers in 2010.[31]

To conclude, there are two points worth raising here regarding the interplay of the policies discussed in this section and the abundance of cheap natural gas. The first is that the future of the policies—especially, those directly related to renewable sources—could be threatened by the abundance of cheap natural gas, a point we also raised in Section III.2. If such policies are indeed endogenous to the price of natural gas, an interesting exercise is that of constructing the counterfactual path of such policies but for the shale gas boom. Second, if we view pro-renewable policies as exogenous to the price of natural gas, renewable penetration will be less sensitive to changes in natural gas prices.

IV.2 The Newly Adopted Clean Power Plan

The most recent development in environmental policy, and arguably the most important, is the Clean Power Plan (CPP) with the final rule issued on August 3rd, 2015. The Clean Air Act authorizes EPA to address emissions from new, modified and restructured, and existing power plants. The CPP calls for a 32% reduction in carbon pollution from the power sector by 2030, relative to 2005 levels. There are also requirements for substantial reductions in criteria pollutant emissions. The EPA estimates that by 2030, SO_2 (NO_x) emissions will be 90 (72) percent lower compared to their 2005 levels. The CPP is estimated to provide climate benefits of $20 billion and health benefits of $14–$34 billion with total net benefits of $26–$45 billion. In what follows, we provide a brief overview of the CPP for existing power plants and discuss the incentives that it creates for

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[30] See `http://programs.dsireusa.org/system/program/detail/734`.

[31] See `http://www.eia.gov/todayinenergy/detail.cfm?id=6270`.

electricity generators.[32]

To begin with, the EPA sets state-specific goals for CO_2 emissions based on three building blocks (BBs) of emission reductions. The first building block (BB1) is reduction in the carbon intensity of electricity generation via heat rate improvements of existing coal-fired power plants. The second building block (BB2) aims at replacing coal-fired with *lower-emitting* gas-fired generation. The third building block (BB3) aims at replacing coal-fired generation with generation from *zero-emitting* renewable sources.

The EPA sets state-level goals by calculating emissions assuming the states were to implement what is known as the Best System of Emissions Reduction (BSER). Loosely speaking, under BSER, emission reductions are possible by adopting previously used technologies and measures shown to be cost-effective. While economists may want to rush to the conclusion that EPA equates the marginal cost of abatement across states, EPA points out that this is not the case. For example, take the BB2 that was put into consideration due to the abundance of cheap natural gas and the increased reliance of the US electric power sector on the fuel. Suppose that the average capacity factor (utilization) in a particular state is 50% and part of the state's generation is coal-fired. EPA calculates emission reductions achieved by replacing coal-fired with gas-fired generation by increasing the capacity factor for natural gas plants to, say 75%, without calculating the cost associated with this increase.[33]

The CPP requires State Implementation Plans (SIPs) with the EPA setting out compliance strategies ensuring that the power plants within states' lines meet the *interim* CO_2 targets for 2022–2029, and the *final* CO_2 target by 2030. It is important to emphasize that states are given a great amount of flexibility to meet their targets. First, they can meet their targets by reducing emissions adopting measures known as "outside the fence line", such as residential energy efficiency programs. Second, states can choose to meet either a rate-based or a mass-based target—see Figure 1. The former is expressed in pounds of CO_2 per MWh of electricity, while the latter is expressed in total tons of CO_2 from electricity generation and is essentially an aggregate cap. States have a third dimension of flexibility in terms of whether they meet their targets individually or by form-

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[32] Detailed information regarding the CPP is available at `http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants`.

[33] Among measures that reduce individual affected EGUs' CO_2 emission rates, the EPA considered co-firing (including 100 percent conversion) with natural gas, because of the abundance of cheap natural gas, and the industry's increased reliance on the fuel. The co-firing measures were deemed more expensive than other available measures for existing sources. Shifting generation to existing natural gas combined-cycle units was an option that was considered particularly attractive in light of the increased availability and lower prices of natural gas. See the discussion on pages 335–336 of the CPP final rule at `http://www3.epa.gov/airquality/cpp/cpp-final-rule.pdf`. The role of the abundance of cheap natural gas is also highlighted in Section 2.1 of the CPP Regulatory Impact Analysis available at `http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf`.

ing a coalition, with a cap-and-trade system among the coalition members being a possibility. It turns out that the instruments available through the last two dimensions of flexibility can have large implications for economic efficiency.

Bushnell et al. (2015) show that rate-based compliance implicitly taxes (subsidizes) generation from power plants with an emission rate above (below) the EPA standard. In the absence of other market failures, this is economically efficient only if demand is inelastic because the resulting equilibrium fails to reflect the entire externality. In contrast, mass-based compliance can be economically efficient because it levies a tax on every plant proportional to their emissions. Economic efficiency is achieved because the standard internalizes the externality via the tax.

Economic efficiency is not guaranteed, however, if all states adopt state-level mass-based standards for two reasons. The first is fairly straightforward; there is no guarantee that the emissions tax equals the social cost of carbon. The second is more subtle and emerges in the absence of emission allowance trading across states. If each state implements its own cap-and-trade program then it is highly unlikely that the allowance prices will be equal across states giving rise to differences in marginal abatement costs across states. In the absence of any frictions, allowance trading eliminates abatement cost differentials and improves efficiency.

While trading across states with mass-based compliance improves efficiency, this is not necessarily the case with rate-based compliance. Recall that a rate-based standard implicitly subsidizes some plants and implicitly taxes others. The actual tax or subsidy for power plant i in state s is given by $\tau_{is} = \lambda_s(\beta_{is} - \sigma_s)$, where λ_s is the shadow value of the emissions-rate constraint, β_{is} is the plant emission rate, and σ_s is the rate-based standard.[34] Trading across states with rate-based compliance equates the shadow values of the constraints across the states. The state-level rate-based standards, however, may lead to an inefficiency. Because the standards differ across states, two plants that are otherwise identical in terms of their emissions, but reside in different states, will receive a different tax or subsidy because of differences in the state rate-based standards. Trading does not equate the state rate-based standards. Therefore, the same plant will be treated differently depending on the state it operates in, which creates inefficiencies. The efficiency implications of the outcomes just described can be substantial because electricity crosses state borders due to the nature of the grid. Bushnell et al. show that the resulting incentives also push states toward adopting rate-based standards instead of the more efficient mass-based standard.

For a coalition of states, adoption of a mass-based standard is best from an efficiency perspective. For an individual state, adoption of a rate-based standard results in lower electricity prices. This benefits consumers in *all* states that form the coalition and, hence, gives them an incentive

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[34] The internal tax from a cap-and-trade program is $\tau_{is} = \lambda_s \cdot \sigma_s$.

to lobby for adoption of rate-based standards. From a generator's perspective, lower electricity prices from the adoption of a rate-based standard can be detrimental to its profits. However, the costs for affected generators fall by more than the electricity prices fall, which leads to a split in incentives for generators. On one hand, generators with operations not affected (e.g., renewables) by the CPP, prefer the high electricity prices associated with the mass-based standard. On the other hand, generators with operations affected by the CPP benefit from the lower compliance costs and prefer the rate-based standard. Holding carbon prices fixed, adoption of mass-based (rate-based) standard is a dominant strategy for the first (second) group of generators.[35]

V Conclusions

Modern day fracking has created an unprecedented abundance of natural gas that led to a dramatic drop in prices triggering sweeping changes in the landscape of the US electric power sector. In the first part of the paper, we argue that the implications of the drop in natural gas prices for global carbon emissions are not straightforward. To paint the full picture, it is important to consider three countervailing effects: coal-to-gas switching in the US electric power sector, an increase in the relative cost of US renewable sources, and an increase in US coal exports. While the first effect leads to a decrease in carbon emissions, the other two effects lead to an increase in carbon emissions. Our position is that without a meaningful cap on global emissions, the shale gas boom is likely to increase global emissions and the period during which natural gas is used as bridge fuel to clean energy should be limited. In the second part of the paper, we review recent environmental policies that have contributed in reducing emissions from the US electric power sector and discuss the complex economics of the newly adopted Clean Power Plan. Although the availability of cheap natural gas has already been factored in US environmental policy and has helped electricity generators to achieve compliance with various rules and regulations, it should not derail policy from its long run objective, which is the transition to a less fossil-fuel dependent economy.

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[35] Burtraw et al. (2010) examine the coordination problem in jurisdictional decision making, similar to the one experienced with the CPP, using a detailed partial equilibrium model of operations and investment to examine interactions among state policies and power markets in alternative scenarios.

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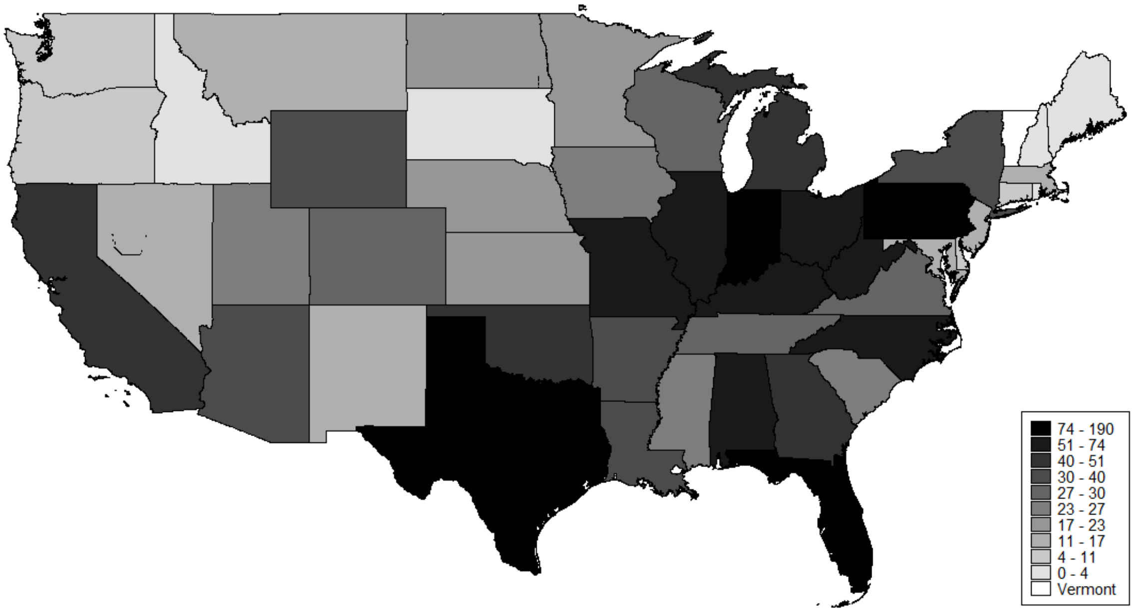
Tables and Figures

Table 1: Coal-fired plant retirements, 2010-2035

Analysis Case	coal-fired capacity retired (GW)	Average size of plants retired (MW)	Average heat rate of plants retired (Btu/Kwh)
Reference	8.8	93	12,338
Transport Rule Mercury MACT 20	13.5	91.4	12,053
Transport Rule Mercury MACT 5	17.8	83.3	12,102
Retrofit Required 20	19.2	84.5	12,034
Retrofit Required 5	44.8	91.2	11,579
Low Gas Price	15.6	104	12,098
Low Gas Price Retrofit Required 20	39.5	97.8	11,576
Low Gas Price Retrofit Required 5	72.6	109.6	11,363
GHG Price Economywide	135.2	157	11,454

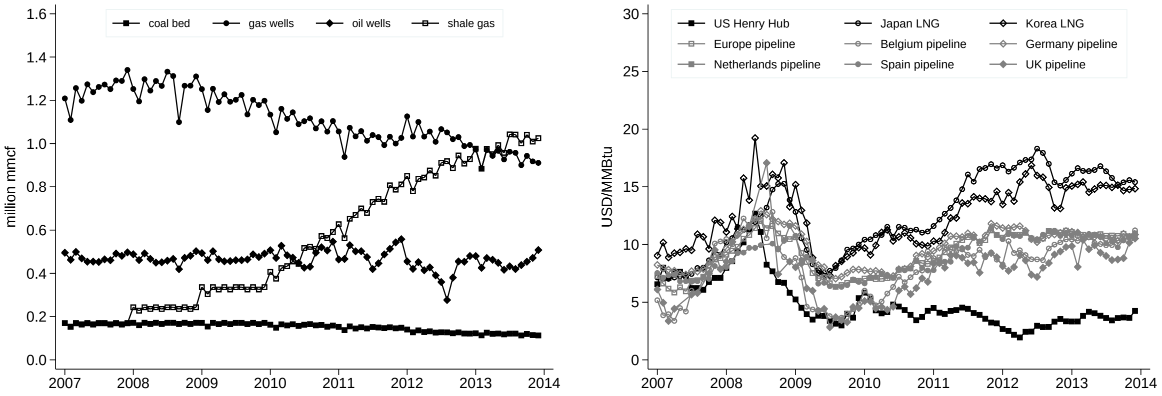
Note: Reproduced from Table 11 in EIA (2011). For additional details regarding the cases considered by EIA, refer to the discussion on pages 48 and 49.

Figure 1: Clean Power Plan final (2030) rule state-specific mass-based targets for CO_2 emissions



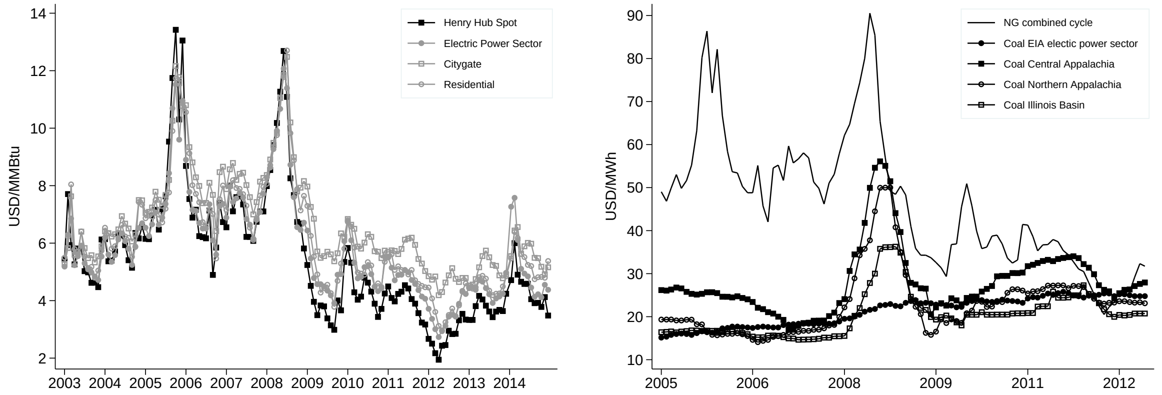
Note: The map is constructed using the numbers (millions of short tons) for 2030 in the Clean Power Plan-State and Tribal Rate and Mass Goals spreadsheet at `http://www2.epa.gov/cleanpowerplantoolbox`.

Figure 2: Shale gas revolution



(a) Natural gas gross withdrawals

(b) International natural gas prices ($/MMBtu)

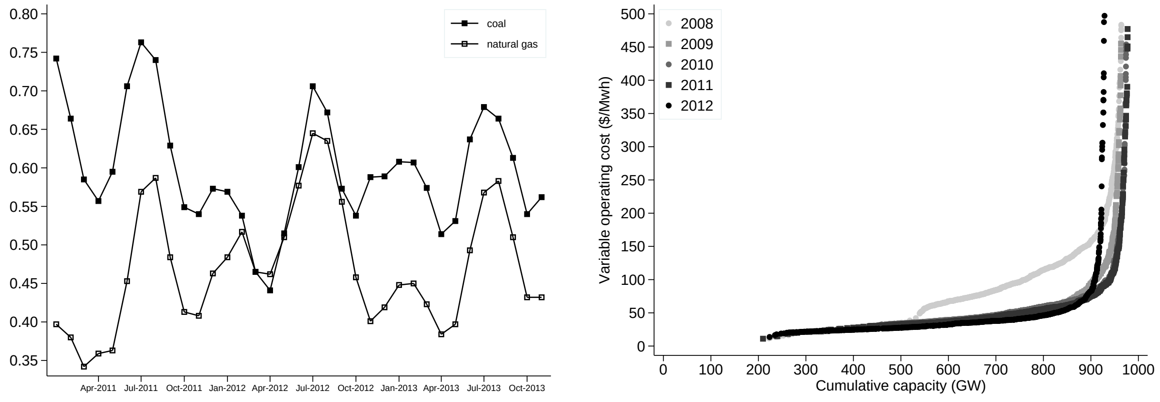


(c) US natural gas prices ($/MMBtu)

(d) Coal and natural gas prices ($/MWh)

Note: The figure is constructed using monthly data from EIA and IEA (international prices). The prices for coal and natural gas in dollars per MWh are based on heat rates of 10,500 Btu/KWh and 7,500 Btu/KWh, respectively.

Figure 3: Short-run coal displacement

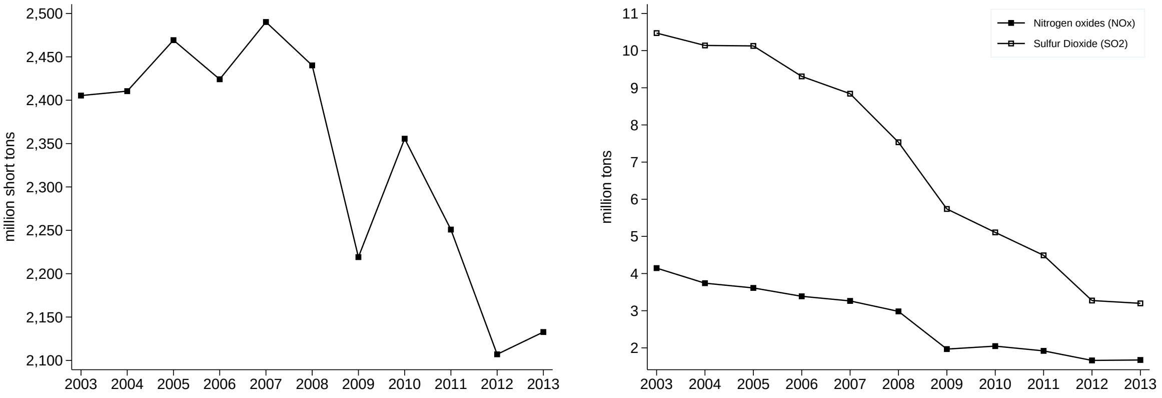


(a) Coal and natural gas capacity factors

(b) Natural gas cost curves, 2008–2012

Note: The cost curves on panel (b) are constructed using data from SNL for the entire United States between 2008 and 2012.

Figure 4: Carbon dioxide and criteria pollutant emissions

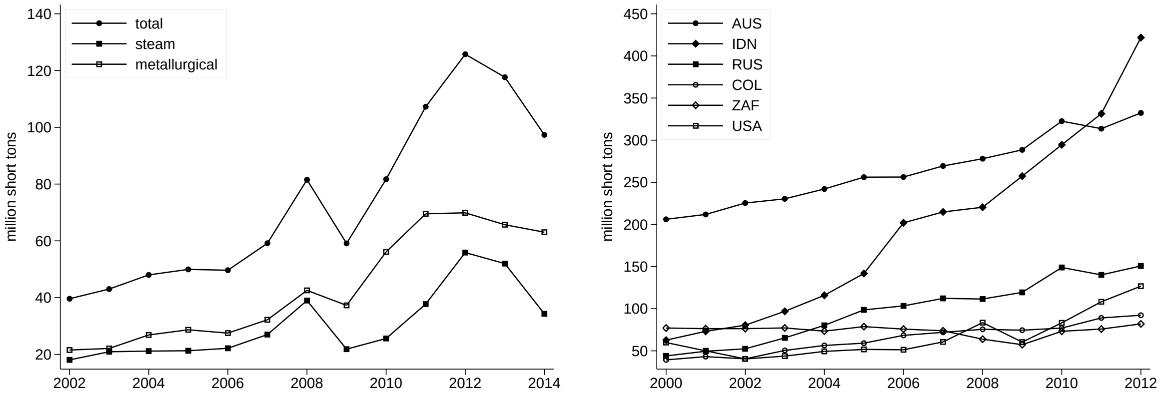


(a) CO_2 emissions

(b) NO_x and SO_2 emissions

Note: The figure is based on authors' calculations using the EPA CEMS data limited to utilities only.

Figure 5: Coal exports



(a) US coal exports (b) Coal exports by country

Note: The figure is based on authors' calculations using the International Energy Statistics from EIA. We use ISO alpha-3 country codes for the legend in panel (b).