

Ripe for Retirement: An Economic Analysis of the U.S. Coal Fleet

Authors:

Lesley Fleischman
Rachel Cleetus
Steve Clemmer
Jeff Deyette
Steve Frenkel

Acknowledgements:

Michelle Davis
Ethan Davis

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The U.S. power sector in transition

In January 2013, Georgia Power announced that it would retire 10 coal units totaling 1,976 megawatts (MW), and in September 2013, American Electric Power announced that it would retire the 580 MW coal-fired Tanners Creek Unit 4. These retirement decisions are part of the dramatic transition underway in the U.S. power sector, in which old and inefficient coal units are being retired in favor of cleaner energy sources like natural gas, renewable energy, and energy efficiency. Since 2009, 20.8 gigawatts (GW) of coal-fired electricity generation has retired, representing 6.2 percent of U.S.’s 2009 coal fleet, and, as of October 2013, another 30.7 GW of coal generators is slated for retirement in the near future.^{1a}

Coal-fired electricity fell from nearly half of U.S. generation in 2008 to 37 percent in 2012. There are many reasons for this decrease in coal-fired generation: an aging and inefficient coal fleet, the low cost of natural gas, the falling costs of renewables, slowing growth in electricity demand, rising construction costs for coal plants, and rising coal prices.² As a result of these economic factors, the Energy Information Administration’s (EIA) latest projections show that very few new coal plants will be built through 2040.³

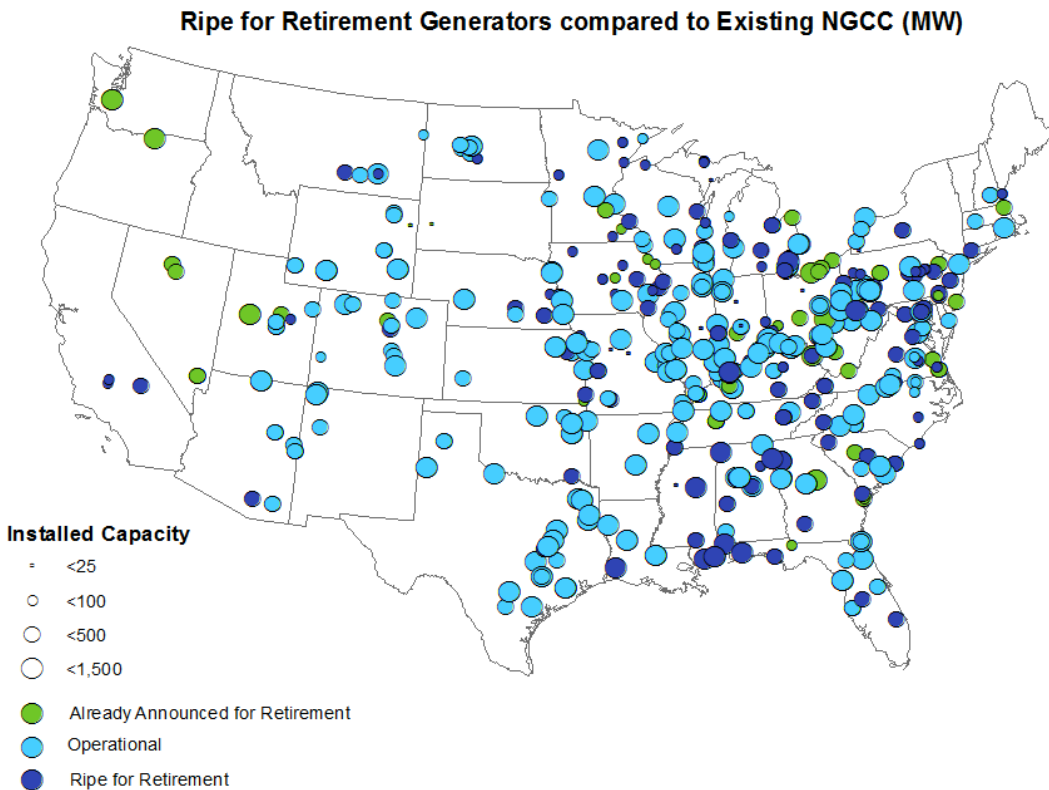


Figure 1: Coal units in the U.S. divided into three categories: those that are currently operating but are already announced for retirement, those that are considered economically competitive in our analysis, and those that are economically vulnerable and thus ripe for retirement.

In addition to these market dynamics, state renewable energy and energy efficiency policies have bolstered the economic viability of renewable energy and energy efficiency. There is also an increasing recognition of the need to upgrade coal plant pollution controls to protect public health and address climate change. Coal is one of the most polluting sources of energy, and coal-fired power plants contributed 74 percent of electricity-related carbon dioxide (CO₂) emissions in 2012.⁴ Harmful pollutants—such as sulfur dioxide, nitrogen oxides, mercury, and particulate matter—released by burning

^a The data set for our analysis was closed in October 2013. During the article submission process, approximately 6.6 GW of coal capacity was announced for retirement, half of which came from a major announced by the Tennessee Valley Authority. Of this, 2 GW were on our ripe for retirement lists.

coal—have been linked to an increase in asthma attacks, heart disease, neurological problems, and premature deaths.

While EPA standards may be hastening and increasing the number of coal plant retirements, it is clear that retirements have been and will continue to be driven by multiple factors. Recent coal plant retirements are part of a long-term trend that started well before EPA began to issue the latest pollution standards.

Numerous recent studies, including *Ripe for Retirement: The Case for Closing America’s Costliest Coal Plants*, a 2012 analysis by the Union of Concerned Scientists, have estimated how much additional coal-fired electricity generation may be economically vulnerable.⁵ Our research takes an analytic approach to understanding the economic factors driving these changes and identifies which coal units are the most vulnerable (see **Figure 1**). We also show that there are several cost-effective options to replace the retiring coal generation and provide policy recommendations that would help enable a transition from coal to cleaner alternatives and address global warming.

An Economic Test for Coal-fired Power Plants

In *Ripe for Retirement*, we examined the economic viability of coal-fired electricity generating units in the United States, providing a snapshot of the economic viability of the U.S. coal fleet based on 2009 data.⁶ However, there have been a number of significant changes in the U.S. electricity market since 2009, which called for a fresh analysis. Therefore, in this paper, we updated our dataset to reflect 2011 data for the coal fleet (the most recent year available), updated cost and performance assumptions for natural gas and wind, and made some important refinements in our methodology in part to provide more regionally accurate results.

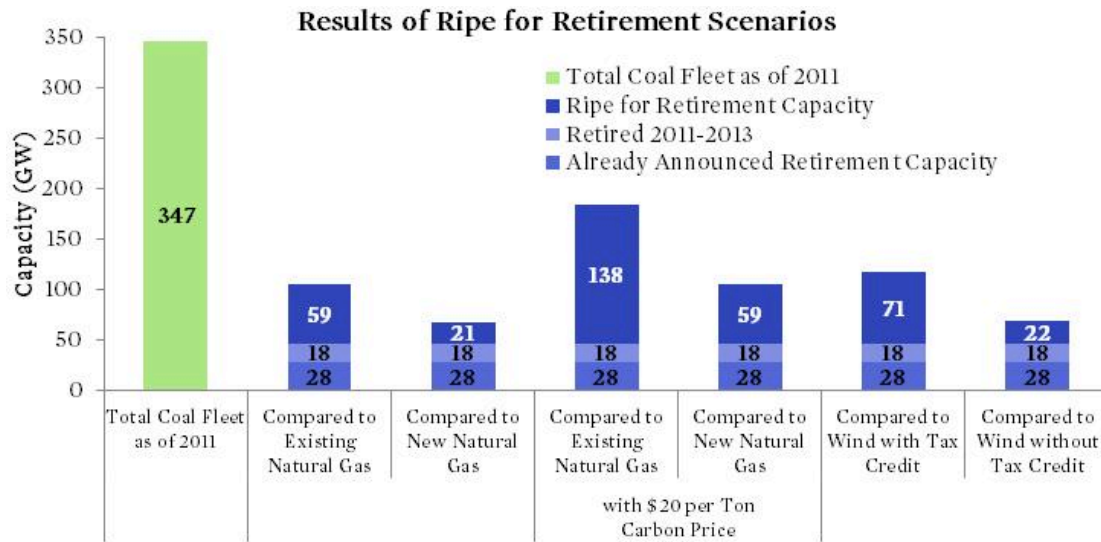


Figure 2: The total capacity of ripe for retirement coal generation varies based on the comparison and the presence or absence of a CO₂ price and tax credits for wind generation.

*Numbers in the carbon price scenarios have been updated.

from alternatives, including existing natural gas combined cycle (NGCC), new NGCC, and wind. First, we identified the base running cost of each coal generator. Second, we determined the absence or presence of four

For both the 2012 report and the current analysis, we employ a three-step methodology based on the one developed by Synapse Energy Economics in its 2011 analysis of coal plants in western states.⁷ To evaluate the economic competitiveness of coal generators, we compared the cost of electricity from individual coal-fired electricity generating units with the cost of electricity generated

types of the most essential air pollution controls to reduce emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter, and mercury, and added the costs of any missing controls to the base running costs for any generator. Third, we determined the relative economic competitiveness of these coal generators compared with average existing and new NGCC facilities with and without a carbon price of \$20 per ton of CO₂ and new wind facilities with and without the production tax credit (PTC). If a coal generator was more expensive than the alternative, it was considered economically vulnerable and, therefore it was deemed ripe for retirement. (See Appendix for full methodology.)

Results

As shown in **Figure 2**, in addition to the 18 GW of coal units that were retired between 2011 and 2013 and the 28 GW that have been announced for retirement by 2025, another 59 GW coal units are ripe for retirement compared with existing NGCC plants (many of which are currently being run well below their maximum capacity factor and could be ramped up), and 21 GW are ripe for retirement compared with new NGCC plants.

Many Coal Generators Economically Vulnerable Even Without New Pollution Controls

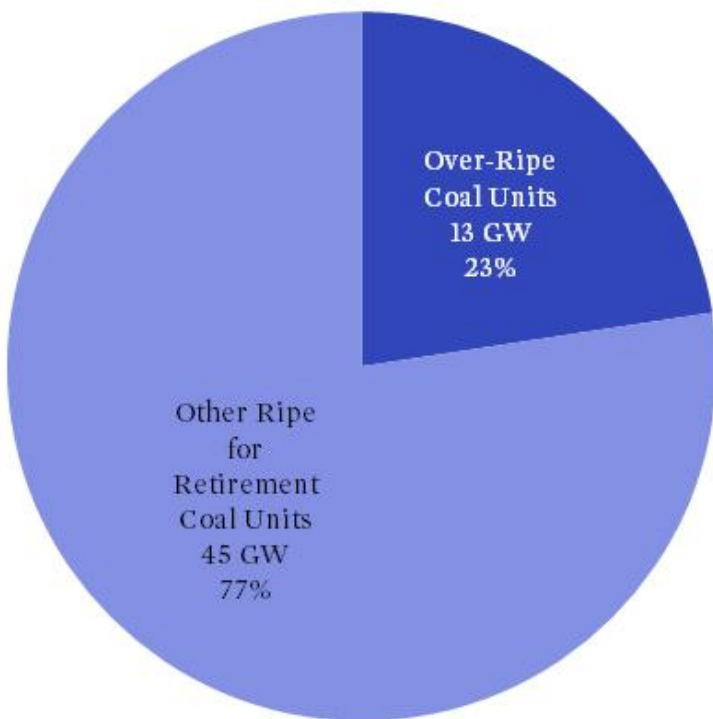


Figure 3: Twenty-three percent of ripe for retirement coal generators are already uneconomic before adding new pollution control costs.

calculated. All units above the lines are ripe for retirement because they are more expensive than the alternatives. In the case where we compared coal units to existing NGCC plants, more than half of the ripe for retirement coal units were located in the Southeast or the Midwest (**Figure 5**).

A \$20 per ton CO₂ price significantly increases the number of ripe for retirement generators. And, a substantial number of coal generators are more expensive than new wind facilities, with or without the PTC. After adding the costs of modern pollution controls, coal-fired units with operating costs that exceed the costs of alternative energy sources should be considered for retirement.

A subset of the ripe for retirement units is *over-ripe*. These 13 GW fail our economic test even without the additional costs associated with installing new pollution controls, and therefore they are the top candidates for closure (**Figure 3**).

Natural Gas Scenarios

The results of the natural gas comparison analysis are shown in **Figure 4**. The solid line represents the national average levelized cost of electricity for existing NGCC plants at various capacity factors, and the dashed line represents the costs of new NGCC plants. Each dot represents a coal unit plotted based on its 2011 capacity factor and the costs we

Wind Scenarios

When we compared coal unit costs to new wind facility costs, the results look somewhat different. States with some of the best wind potential, such as Texas and Oklahoma now appear among the states with the most ripe for retirement coal capacity. Further, even in a region with relatively lower wind potential, states like Alabama and Georgia still have a significant number of coal generators that remain economically vulnerable (**Figure 6**).

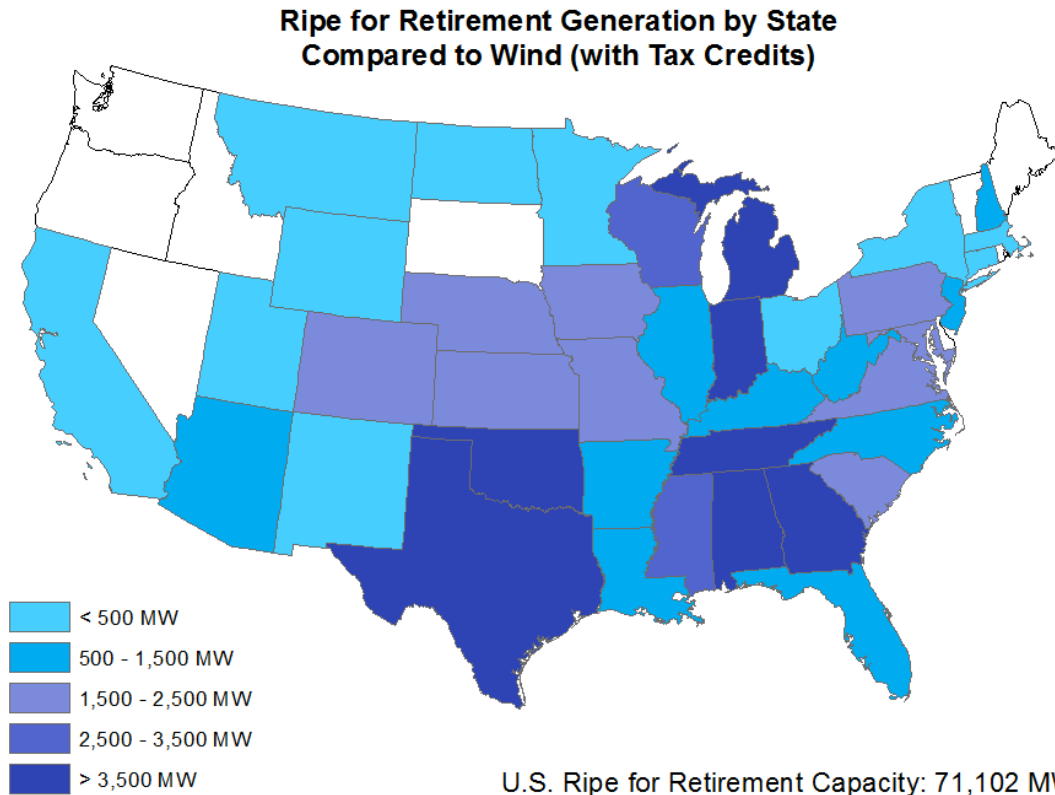


Figure 6: When compared with new wind projects, Oklahoma and Texas—two states with strong wind energy resources—move up in the rankings of ripe for retirement coal capacity.

For the wind comparisons, we varied the average capacity factor by NERC region, based on estimates of total available wind capacity (see methodology in Appendix). In regions with higher quality wind resources, average wind capacity factors are higher and therefore costs per megawatt-hour (MWh) are lower. Conversely, in regions with lower quality wind resources, capacity factors are lower and costs per MWh are higher (**Figure 7**).

Our wind scenario most likely represents a lower bound of the total amount of coal that is uneconomic compared with wind, because we only compared coal plants to the wind facilities located within their same region. However, recent evidence suggests that this regional comparison might not always be appropriate. Georgia Power Co., a subsidiary of Southern Company, for example, has recently signed agreements to import 250 MW of wind power from Oklahoma to Georgia and Alabama, in part to replace retiring coal capacity.⁸

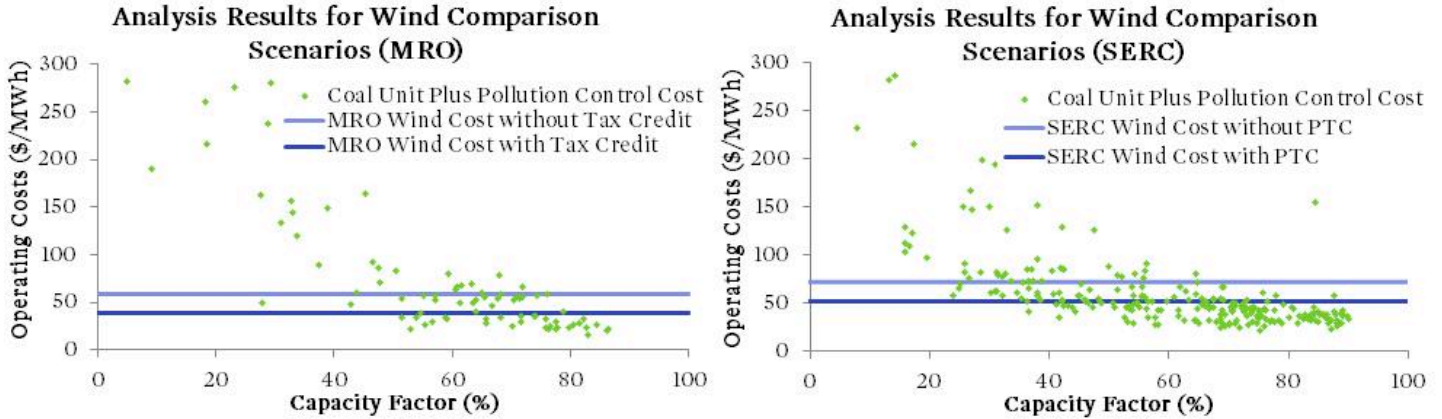


Figure 7: Two NERC regions are shown to demonstrate the effects of wind capacity factors on wind costs and coal retirements in our wind comparison scenario. The MRO region (the upper Midwest) has higher than average wind potential, while the SERC region (the Southeast) has lower than average wind potential.

Comparison of Results to Other Studies

The results of our analysis are in line with a broad cross-section of other similar studies that have looked at the economic viability of the U.S. coal fleet—including analyses by investors, regional utility organizations, energy consultants, and non-profit groups. A vast majority show a range of approximately 25 to 100 GW of coal retirements by 2020, which conforms with our results. One recent study, however, found a much higher range. Synapse Energy Economics’ 2013 analysis, *Forecasting Coal Unit Competitiveness*, identified between 228 and 295 GW of coal capacity as economically vulnerable. In that study, Synapse included costs associated not only with the four air pollution controls we considered, but also cooling water, coal ash, water effluent controls, and a higher CO₂ price.

It is important to note that the assumptions used to derive the estimates in each study vary considerably and thus they may not be directly comparable. For example, they differ in terms of what factors were considered apart from the EPA standards (e.g. assumptions about natural gas prices, future prices for coal, costs for wind and other renewable energy alternatives, financing costs etc.), which pollution standards were included, and the level of stringency assumed for a given standard. However, they do encompass a wide range of views and assumptions so provide a good indication of the scale of change facing the U.S. coal fleet.⁹

Implications of Ripe for Retirement Analysis

Retiring a large amount of coal-fired generation represents a transition that is both a challenge and an opportunity. The decisions each state and region makes about how to respond to this transition will have significant and lasting implications. As old coal plants retire, multiple affordable and cleaner resources are available to fill the gap. These include natural gas, renewable energy, efficiency, and demand-side management.

Our analysis found that every region of the country has the potential to replace the generation from the combined total of 138 coal units retired between 2011 and 2013, 150 units slated for retirement in the near future, and 329 additional units we identified as ripe for retirement. The recent generation levels of these coal units can be replaced through a combination of new renewable energy generation, energy efficiency savings, and underutilized existing NGCC plants. **Figure 8** shows that substantial excess capacity is available if we

assume that existing NGCC plants can be ramped up to their full technical potential, an average 85 percent capacity factor.

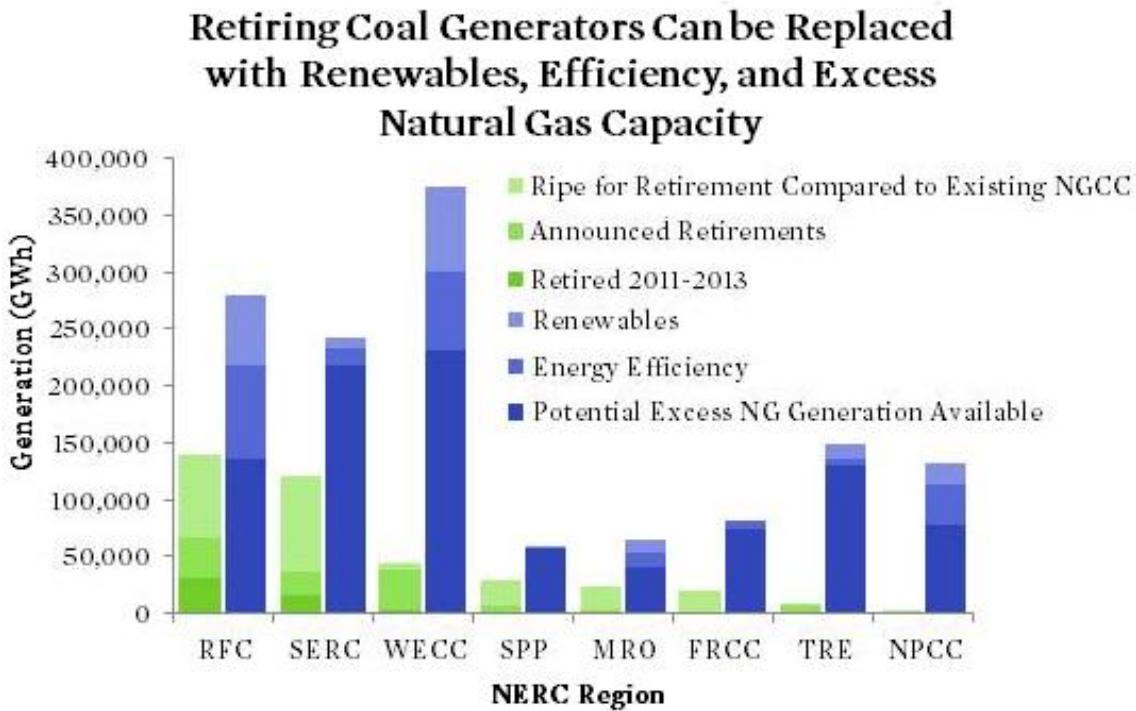


Figure 8: Renewable energy and energy efficiency projections are based on projected development through 2020 as a result of existing policy requirements, including state-level renewable electricity standards and energy efficiency resource standards. Potential excess natural gas generation is based on additional generation from ramping up existing NGCC plants to an 85 percent capacity factor.

In fact, as **Figure 9** shows, in every NERC region except RFC, the capacity factor needed for existing NGCC plants to replace all retiring coal is well below 85 percent. On average across NERC regions, retiring coal can be replaced by boosting existing NGCC from the 2011 national average capacity factor of 39 percent to about 58 percent. Further, when we also include the renewable energy generation expected from existing state-level renewable electricity standards (RES) and the reduced power demand due to existing state energy efficiency resource standards (EERS), needed NGCC capacity factors are even lower (in some cases even lower than 2011 capacity factors).

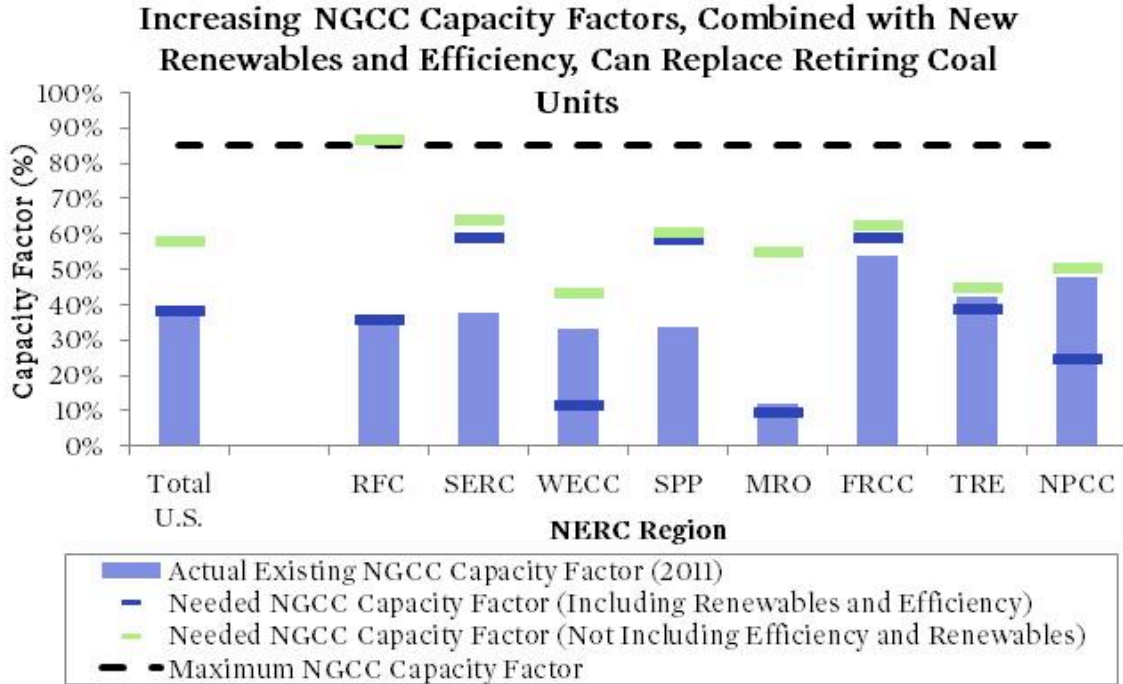


Figure 9: On average in 2011, the 242 GW U.S. NGCC power plant fleet operated at just 39 percent of its design capacity.¹⁰ In most regions, only a small increase in capacity factors at existing NGCC plants would be needed to replace retiring coal and coal that is ripe for retirement. If renewable energy generation and efficiency savings are included, the increases in NGCC capacity factors that would be needed are even more modest.

Switching to Natural Gas

There is evidence that utilities have been replacing generation from retiring coal plants with generation from natural gas-fired plants. This has been a seemingly attractive option because of the excess generating capacity currently available from existing natural gas plants coupled with the current abundant supply of natural gas and low natural gas prices. Utilities have ramped up natural gas primarily through a combination of increasing their utilization of existing NGCC plants, converting coal plants to natural gas, or building new NGCC plants. For example, in Ohio, 2.1 GW of coal capacity was retired between 2011 and 2013 and another 4.9 GW of coal is scheduled to be retired by the end of 2015. Some of this capacity has been replaced with existing NGCC units—the average capacity factor for a NGCC unit in Ohio increased from 8 percent in 2008 to 58 percent in 2012. In addition, new NGCC units totaling 4.1 GW have been built or are planned.¹¹

While natural gas is currently an economically attractive option for replacing coal generation, a significant increase in the nation’s dependence on natural gas has many risks. As with any fossil fuel, burning natural gas for electricity generation results in the release of CO₂ and thus contributes to global warming. In addition to these direct smokestack pollutants, the drilling and extraction of the fuel from wells, and its distribution in pipelines, also results in the leakage of methane—a primary component of natural gas that is 25 times stronger than CO₂ at trapping heat over a 100-year period.¹² Thus, while a new natural gas plant emits 50 to 60 percent fewer greenhouse gas emissions than coal, a transition from a coal to a natural-gas-dominated electricity system would not be sufficient to meet U.S. climate goals.¹³ Further, volatile and rising natural gas prices and potential shortages (due to unforeseen factors that may increase demand or decrease supply), and other economic factors also add a dimension of consumer risk from the expanded use of natural gas.

Scaling up Renewable Energy

In many parts of the country, the retirement of coal will also mean drawing more on renewable energy resources. A diversified electricity system—with amplified roles for renewable energy and energy efficiency and a modest role for natural gas—would both limit the threat of climate change and mitigate the risks of an overdependence on natural gas. In a few cases, utilities have announced plans to build new renewable energy facilities to replace generation from retiring coal units. For example, as part of a settlement with an environmental group and the Environmental Protection Agency, American Electric Power agreed to retire its Muskingum River Power Plant Unit 5 and to develop a total of 200 MW of wind energy.¹⁴

Existing state policies have been instrumental in ramping up renewable energy resources. Twenty nine states now have a RES in place, including seven Midwestern states—a region with many economically vulnerable coal generators and tremendous renewable energy potential. For example, the RES policies in Minnesota and Illinois support two of the largest markets for new renewable energy outside of California. At the national level, tax credits have been an important driver for renewable energy development and attracting new domestic manufacturing capacity. However, several short-term extensions and lapses in these tax credits over the past decade have created a boom-bust cycle and significant investment uncertainty for the renewable energy industry.

Even without sustained federal support, recent data show that in many parts of the country wind power is cheaper than new coal plants. The costs of well-situated wind facilities are even economically competitive with new natural gas plants. In 2012, for example, wind accounted for 42 percent of new generating capacity installed in the United States, leading all energy technologies (including natural gas) by adding more than 13 GW of new capacity.¹⁵ Technological advances and growing economies of scale have driven down wind costs by about 80 percent over the last three decades. While there were significant cost increases in the early-to-mid 2000s, the weighted average cost of generating electricity from wind in the U.S. declined by more than 40 percent between 2009 and 2012.¹⁶ Crucially, wind power requires no fuel and many wind facilities are able to lock in long-term fixed price contracts with utilities, so it is not prone to the price volatility to which natural gas (or any fossil fuel) is chronically vulnerable.

The costs of solar photovoltaics (PV) have also been falling rapidly because of a steep drop in manufacturing costs. As a result, PV capacity in the U.S. has reached 8.9 GW.¹⁷ Costs of both wind and solar are predicted to fall even further as additional economies of scale are realized and technological innovations occur. Other resources, such as bioenergy and geothermal energy are also promising and can be run around-the-clock just like a coal or natural gas “baseload” plant.

Investing in Efficiency and Demand Side Management

Energy efficiency is one of the quickest and least costly ways of replacing existing capacity. Efficiency investments mean that some coal plants can be retired without a need to replace that capacity, while other power plants could simply be run more cheaply—all of which could mean that consumers could lower their electricity bills. It costs a utility an average of 2.5 cents per kWh to invest in energy efficiency measures, as compared with 6 to 15 cents per kWh for new generation sources.¹⁸ Twenty four states have adopted EERS and have already achieved significant energy savings. Recent data show that nine of these states have achieved energy savings of over 1.5 percent of their electricity sales.¹⁹

Policy recommendations

In October 2013, Brayton Point Station, the largest remaining coal-fired power plant in New England and a leading source of toxic pollution and CO₂ emissions in Massachusetts, was announced for closure in 2017. Dominion Resources, its previous owner, had already spent over \$1.1 billion to install new pollution controls at the plant, however financial analysts projected it would lose over \$3 million in 2014 largely because of low natural gas prices.²⁰ Cases like this highlight the imprudence of making major capital investments in old coal-fired plants that ultimately cannot survive the adverse economic climate for coal. This is a critical moment for utilities, investors, and electricity regulators and planners to take stock of new market realities and make investment, policy, and planning decisions that align with long term goals for transforming the electricity sector to a cleaner, more sustainable one.

Renewable energy and energy efficiency can play an important role in meeting energy demand and helping to maintain reliability as coal plants are retired. While there are considerable challenges at the federal and state levels, future success in ramping up the share of these resources depends critically on policies such as strong renewable electricity standards and energy efficiency standards, tax credits, investments in research and development, and improved processes for planning, siting, and financing of transmission projects. Carbon pricing would also provide utilities with an incentive to shift to lower carbon resources like renewables. In addition, State Implementation Plans for complying with EPA pollution standards that explicitly include a role for efficiency and renewable energy as compliance options could provide further support for these resources.

Investments in transmission are especially critical for helping to reliably integrate power from the best-situated renewable energy resources into the grid. FERC's recently issued Order 1000 and its other market initiatives provide important frameworks to plan for renewables and demand-side contributions to the reliability of the electric system. Order 1000 requires transmission planners to consider state and federal public policies, such as state RES and EERS, as drivers for transmission development. It also requires planners to provide comparable treatment for alternatives to traditional generation, like efficiency and demand-response measures, throughout the transmission planning process.²¹ As grid planning and operations are increasingly adapted to make use of abundant renewable and demand-side resources, coal plant retirements are less relevant to reliable and economic electricity supply.

State Public Utility Commissions, Independent System Operators, and Regional Transmission Organizations should also conduct comprehensive resource planning to ensure that their planning decisions and deliberations over pollution control-related investments and costs incorporate the new realities about the diminishing role of coal and the need to ramp up alternatives. There is growing recognition of the benefits of diversifying the predominantly coal-based electric generating system and investing in renewable energy and energy efficiency.

Conclusion

The nation's fleet of coal plants is becoming less and less economic. Many older, dirtier, and underutilized coal units simply cannot compete with natural gas or wind power. Combining these and other cleaner resources with upgrades to the power grid and investments in energy-saving technologies can more than replace the generation from the 329 coal-fired generators (58.7 GW) we identified as ripe for retirement.

Utilities, investors, grid operators, and regulators should seriously assess whether cleaner alternatives can more affordably meet customers' energy needs instead of burdening ratepayers with hundreds of millions of dollars

of capital investments to extend the life of uneconomic coal plants. Thoughtful planning about how to retire coal plants can help maximize economic returns, human health, and environmental benefits of a cleaner energy future, while maintaining reliable and affordable power for American families and businesses.

Appendix:

Methodology

We compiled a database of all utility coal-fired generators in the United States as of 2011—the last year for which full data were available.²² We started with a universe of all 1,191 coal generators in the U.S. in 2011, and then we removed all units that were retired in 2013 or earlier. We also removed coal units that had been “out of service” or “mothballed” in 2011 because these units lack operational data for that year. Likewise, we removed units with capacity factors under 1%, because such low capacity factors distort our economic calculations. Finally, we separated out the 150 coal units that had already been announced for retirement as of September 2013. After these exclusions, we had a sample of 788 coal units in our analysis, totaling 290 GW, which accounts for 89 percent of the operating coal fleet in 2013 (**Table 1**). For the remaining coal units, we applied an economic test that draws from the methodology developed by Synapse for its *Environmental Controls and the WECC Coal Fleet* analysis.²³

Table 1:
Coal Fleet Characteristics

	Number of Generators	Total Capacity (MW)	Average Capacity (MW)	Average Age	Average Capacity Factor
<i>Total Coal Fleet as of 2011</i>	<i>1,191</i>	<i>347,054</i>	<i>291</i>	<i>38</i>	<i>61%</i>
Announced for Retirement	150	28,164	188	48	47%
Retired 2011-2013	138	18,204	132	52	34%
Excluded from Analysis	115	10,231	89	16	23%
Coal Units in Analysis	788	290,456	369	37	65%

We calculated the running costs for each coal plant by adding unit fuel costs and operating and maintenance (O&M) costs. We used assumptions from the NERC 2010 Special Reliability Scenario Assessment to estimate the fixed and variable O&M costs. Based on these data, we developed a cost curve (**Figure 10**).

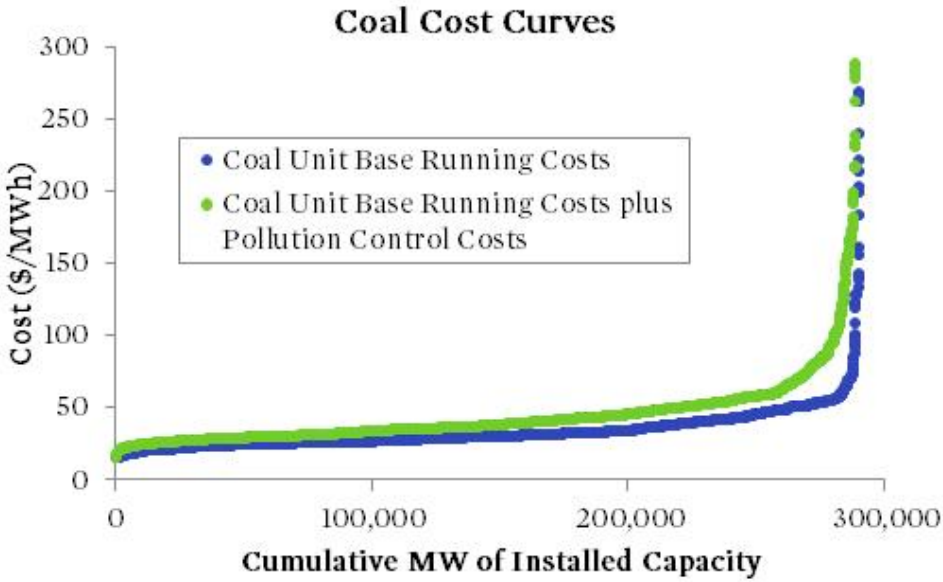


Figure 10: The coal unit cost curve shifts upward when the costs of needed pollution controls are added to base running costs.

(ACI) for mercury.²⁵ We estimated the total costs of adding wet scrubbers and SCR using data from the EPA Integrated Planning Model.²⁶ We used assumptions from the Eastern Interconnection Planning Collaborative to estimate costs of adding baghouses and activated carbon injection systems.²⁷ In addition, we adjusted pollution control cost estimates such that if multiple units used a single flue, SO₂ and particulate matter pollution controls costs would be shared. Likewise, if multiple units shared the same boiler, NO_x, and mercury control costs would be shared.

Some of the coal generators in the operational fleet installed pollution control technologies after 2011. In these cases, we added the O&M costs—but not the capital costs—of these controls, and then added those costs to our base operating cost estimates for 2011. This allowed us to include generators that had pollution controls installed in 2012 or later but also to ensure that the costs of adding those technologies were included in our economic comparisons with cleaner alternatives for these generators.

After estimating the base operating costs and the cost of adding pollution controls for those coal generators lacking pollution controls, we applied our economic test by comparing the estimated total cost to operate each coal generator at its 2011 capacity factor against the cost of producing power from three competitive energy resources: existing NGCC plants, new NGCC plants, and new wind facilities.

The cost and performance assumptions for the alternative technologies were taken largely from the EIA’s Annual Energy Outlook 2013, except for wind capital costs, which came from the DOE Wind Technologies Market report.²⁸ We used these assumptions to calculate the levelized cost of electricity for competing electricity sources (**Table 2**).

Table 2:
Cost and Performance Assumptions for Alternative Technologies

(2011\$)	Existing Natural Gas	New Natural Gas	Wind without Tax Credit
Overnight Capital Costs (\$/kW)	0	1,006	2,000
Fixed Charge Rate	0	12%	9%
Fixed O&M (\$/kw-yr)	15.10	15.10	38.86
Variable O&M (cents/kWh)	0.31	0.31	0
Heat Rate (Btu/kWh)	7,887	6,430	0
Average Natural Gas Price (AEO 2013) (\$/MMBtu)	4.65	4.65	0
Fuel Escalation Rates (20-yr) (%)	2.5%	2.5%	0
Fuel Cost (avg. price) (cents/kWh)	4.6	3.73	0
Capacity Factor (%)	85%	85%	35%*
Levelized Cost of Electricity (LCOE) (cents/kWh)	5.16	6.78	7.07*

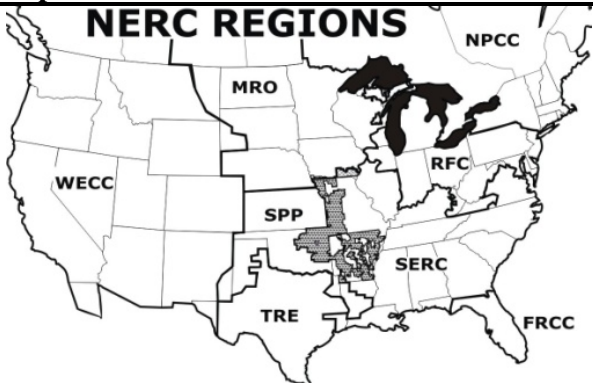
*Actual capacity factor and LCOE for wind vary by NERC region (see below).

We ran the natural gas scenarios with and without the inclusion of a \$20 per ton CO₂ price, and we ran the wind scenarios with and without the inclusion of the PTC, which has a 2-cent/kWh levelized value over a 20-year period.

In addition, we calculated the cost of generating electricity from wind using region-specific average capacity factors based on projected wind availability in different NERC regions.²⁹ We started with NREL’s estimate of total potential wind resources for wind turbines with 80-meter hub heights in each state, which included several land use exclusions. Then, we aggregated generation and capacity values by NERC region. Then, we calculated how much wind would be needed to replace half of the coal generation in the region. We started with the highest quality wind resources and worked our way down until we had sufficient generation. To account for the fact that not all of the best wind resources may be available, we allowed only 75 percent of the highest quality wind resources to be used in our estimate. Finally, we calculated both the generation and capacity of wind needed to replace the coal fleet and calculated the average capacity factor of this resource (**Table 3**).

Table 3:
Wind Capacity Factor Assumptions

NERC Region	Capacity Factor
WECC	47%
MRO	46%
SPP	46%
TRE	46%
NPCC	40%
SERC	37%
RFC	35%
FRCC	n/a



The map shows the following regional assignments: WECC (Western US), MRO (Midwest), SPP (Southwest), TRE (Texas), NPCC (Northeast), SERC (Southeast), RFC (Florida), and FRCC (Florida).

* These are regionally-averaged capacity factors based on 2010 wind resource data developed by AWS Truepower for the National Renewable Energy Laboratory³⁰ and updated with higher average capacity factors for each wind class based on 2012 data from Lawrence Berkeley National Laboratory that reflects recent advances in wind turbine designs.³¹ (The average regional wind capacity factor is calculated based on both

wind quality in a region (including several land-use and environmental exclusions) and coal capacity in a region. For example, RFC has some high quality wind resources and also has large amounts of ripe for retirement coal. In such regions it may be necessary to call on some lower wind class resources to meet generation needs as coal is retired, which lowers the average capacity factor we used for this region. And, although much of the Southeast has low wind resources, SERC includes most of Missouri and Illinois, states with high quality wind resources, which pulls up the average capacity factor for this region.)

Limitations and Uncertainties

We obtained power plant and unit operational information that was reported by companies to the EIA. We compiled data on pollution controls by cross-referencing both EIA and EPA databases. The data used in our analysis is correct to the best of our knowledge, but reporting errors could impact our results.

We used national-level assumptions to estimate the costs of operating coal plants, the costs of new and existing gas plants and new wind facilities, the costs of new pollution controls, and natural gas prices. Regional variations in these values could impact our results. We ran the wind comparison case with regional capacity factor assumptions, but this does not capture state- and site-specific variation.

We looked at the costs of adding air pollution controls to coal plants. Other environmental factors—such as cooling water temperature controls, coal ash disposal, water pollution, and limits on CO₂ emissions—were not captured in this analysis.³² Potential regulations on these environmental factors could also impact coal plant economics.

We looked at the costs of installing modern pollution controls at coal plants that currently lack these controls. However, the retrofits that we assumed may not match up directly with the compliance requirements of any particular environmental regulation.

Our analysis does not capture the dynamic nature of power markets. We used data from a single year to analyze a snapshot in time. The most recent year for which there is full data is 2011. Any significant operational changes since 2011, therefore, are not captured in our analysis.

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