Forecasting Coal Unit Competitiveness

Coal Retirement Assessment Using Synapse's Coal Asset Valuation Tool (CAVT)

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1. EXECUTIVE SUMMARY

As new, more stringent federal environmental regulations come into effect, the fleet of U.S. coal-fired power plants is becoming increasingly less economic in comparison to the alternative of electricity market purchases. Numerous industry groups, environmental advocates, and government agencies have published estimates of the U.S. coal capacity at risk of retirement. However, all of these estimates have been conservative in that they have excluded the costs of installing and operating some of the controls expected to be required for compliance with environmental regulations, and/or they have assumed a long-run carbon-emission price of zero.

This study explores a more comprehensive set of assumptions, using Synapse's Coal Asset Valuation Tool (CAVT). CAVT is a spreadsheet-based database and model that forecasts the costs for individual coal units to comply with environmental regulations, and compares these forecasts to electricity market prices. It includes cost estimates for all expected environmental retrofits along with carbon prices.

Compared to other studies, Synapse's analysis shows more coal capacity to be uneconomic, or "at risk." Based on CAVT analysis, our mid-case projection indicates that 95 percent of current U.S. coal capacity is uneconomic compared to wholesale electricity market purchases from existing power plants, and 73 percent is uneconomic compared to the all-in costs of building and operating new plants (see Table ES1). These findings indicate that it would be cheaper to retire rather than to continue operating 228 to 295 GW of coal, out of a total 311 GW operating in the United States in 2012.

Table ES1. Uneconomic U.S. coal capacity compared to market purchases: mid-cases and sensitivities

Uneconomic Coal Capacity Compared to Energy-Only Purchases (GW)

		Environmental Retrofit		
		Lenient	Mid	Strict
Natural Gas Price	High	192 (62%)		292 (94%)
	Mid		295 (95%)	
	Low	254 (82%)		306 (98%)

Uneconomic Coal Capacity Compared to All-In Purchases (GW)

		Environmental Retrofit		
		Lenient	Mid	Strict
Natural Gas Price	High	63 (20%)		230 (74%)
	Mid		228 (73%)	
	Low	101 (33%)		274 (88%)

Note: Percentages indicate the share of the capacity of the uneconomic units compared to total coal capacity.

The results of our sensitivity analysis (also shown in Table ES1) suggest that a significant portion of the coal fleet is uneconomic and should be retired under a wide variety of future scenarios, including higher and lower than expected natural gas prices, and stricter and more lenient than expected environmental control requirements. Of course, market conditions are likely to change as coal plants retire—for example, natural gas prices may rise or coal prices drop—shifting these cost comparisons. Our analysis focuses on each plant's individual economics, and not on the broader macroeconomic ramifications of retiring most of the country's coal capacity en masse.

2. INTRODUCTION

As of mid-2013, retirements have been announced for 36 of the 311 gigawatts (GW) of coal capacity in the United States. But that's just the beginning. In strictly economic terms, many more coal units are no longer worth running; it would be cheaper to retire these units and purchase market power than to invest in retrofits to comply with new, more stringent environmental regulations.

Synapse uses its Coal Asset Valuation Tool (CAVT) to analyze which U.S. coal plants are ripe for retirement. CAVT is a spreadsheet-based database and model that aggregates publicly available data (such as capacity, generated power, and heat rate) on non-cogenerating coal units and combines this with publicly available cost methodologies to calculate the cost of complying with environmental regulations. The calculated future cost of each coal unit—that is, the discounted present value of costs from 2013 to 2042—is compared to the estimated future cost of wholesale electricity market purchases to determine future economic viability on a unit-by-unit basis. All costs in this report are the net present value accrued from 2013 through 2042, based on a 4.71 percent real discount rate, in 2012 dollars.

This study uses CAVT to assess U.S. coal units' economics compared to the "all-in" market price of energy (based on the cost of constructing and operating a new natural gas combined-cycle plant) and the "energy only" market price (based on the cost of operating an existing natural gas combined-cycle plant).

Section 3 of this report evaluates U.S. coal units' economics compared to "typical" national market prices for electricity, and investigates the effects of using differing assumptions in CAVT for gas prices and the stringency of environmental regulations. Section 4 demonstrates how CAVT can provide detailed cost analysis for individual coal units compared to region-specific market prices, and Section 5 summarizes the assumptions used in other recent studies assessing coal at risk for retirement.

Appendix A describes the methodology used by CAVT in its calculations, and identifies the underlying data and assumptions used in this report regarding coal unit characteristics, electricity market prices, and environmental control requirements. Appendix B presents the results of a sensitivity analysis testing the effects of a "very high" gas price assumption on the market competitiveness of coal units.

3. ASSESSING THE U.S. COAL FLEET

From the 816 MW Big Sandy 2 in Kentucky to the 15 MW Chamois 1 in Missouri, coal units all over the country are announcing their upcoming retirements. Twelve percent of U.S. coal capacity—201 coal units with a combined capacity of 36 GW—is currently slated to retire. One-third of these units will retire by 2015; 90 percent by 2016. On average these units are smaller than the typical coal-fired unit in the United States—180 MW as compared to the mean coal unit, 350 MW. Most of the retiring units (60 percent) are in either the East North Central region (WI, MI, IL, IN, OH) or the South Atlantic region (FL, GA, SC, NC, VA, WV, MD, DC, DE).

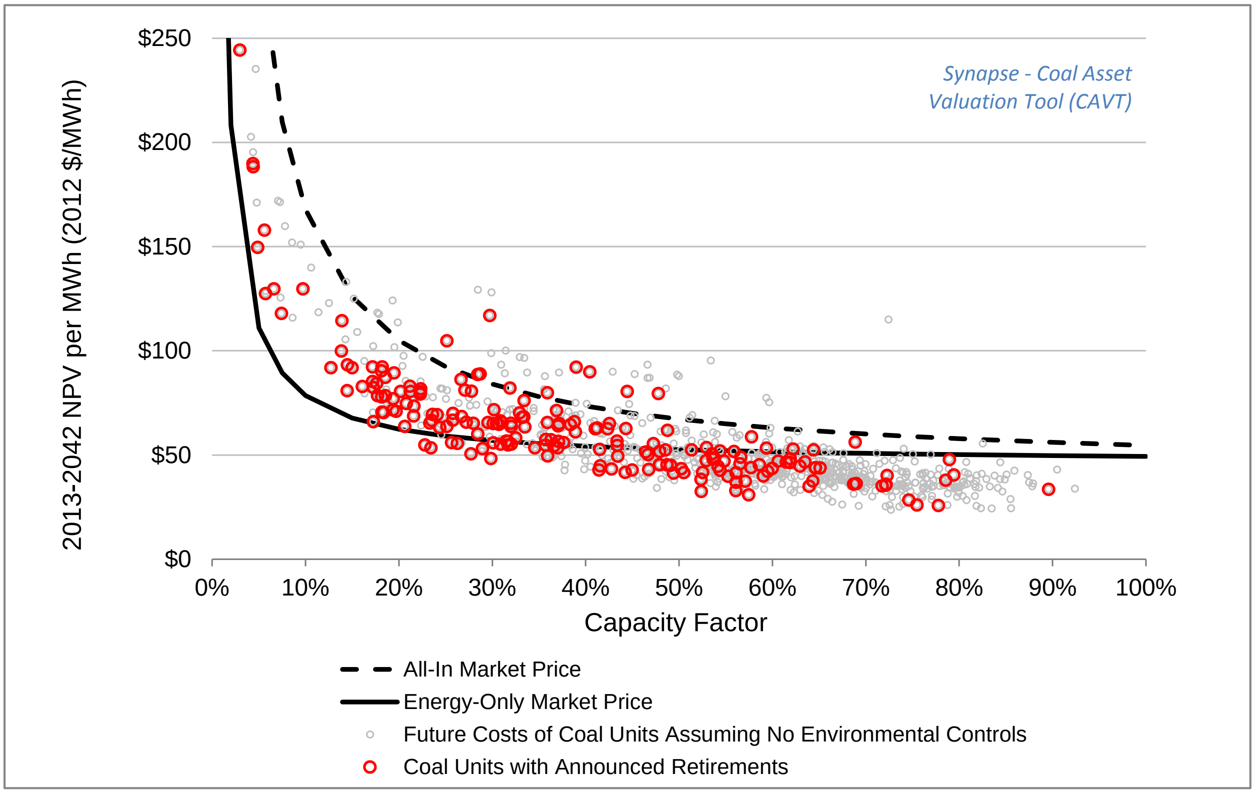
3.1. Coal Unit Competitiveness With and Without New Retrofit Costs

Based on CAVT estimates, Figure 1 illustrates how U.S. coal units compare economically to market electricity purchases, assuming no additional environmental retrofits beyond those that had already been installed in 2012. Each unit's current operating costs[1] (in 2012 dollars per megawatt-hour) are plotted against that same unit's current annual capacity factor (shown as grey circles).[2] Markers for the coal units that have announced their retirements are circled in red.

[1] Operating costs include unit-specific fixed and variable operating and maintenance costs, coal fuel costs, and for units that currently have environmental controls, fixed and variable operating and maintenance costs associated with those controls. Current costs for generating units include neither the capital nor the operating costs of required environmental costs that have not yet been installed, and only include the carbon costs associated with the existing Regional Greenhouse Gas Initiative for the plants to which it applies.

[2] Annual capacity factor refers to the ratio of generation produced by a coal unit to the total possible generation over a year. It is commonly expressed through the formula: Annual Unit Generation / (Unit Capacity x 8760 hours).

Figure 1. Projected net present value of coal units assuming no new environmental retrofits compared to typical national market electricity prices, 2013-2042



Also shown in Figure 1 are two curves approximating the wholesale market price of electricity under the same scenario (no additional environmental controls or carbon price). The lower, solid line depicts an energy-only market price based on the operating costs of an existing natural gas combined-cycle plant. The higher, dashed line depicts an "all-in" market price based on the cost of constructing and operating a new natural gas combined-cycle plant. In this figure, market prices include the assumption of a natural gas price that closely follows the U.S. Energy Information Administration's (EIA's) reference case—starting at the national 2013 average price of $4.42/MMBtu and increasing by an annual average rate of 2.24 percent.[3]

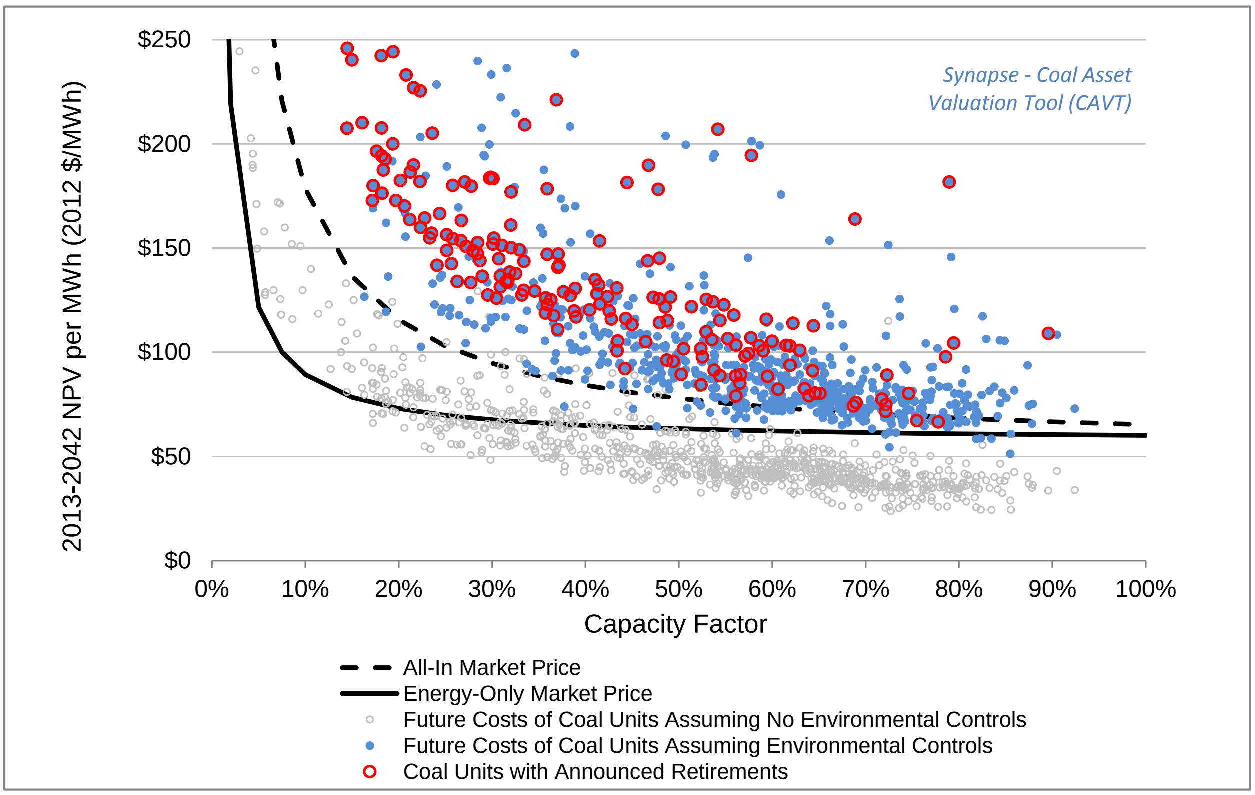
If a coal unit's marker appears below the market price curves, it is more economic to continue running the unit than to retire it and purchase market power. If the unit's marker appears above the market price curves, it is more economic to retire the unit and purchase market power. Two-hundred and one units are outlined in red, indicating that their retirements have been announced. Figure 1 shows that, if you don't account for expected retrofit costs, many of the units slated for retirement are economic compared to the energy-only market price, and even more are economic compared to the all-in market price. Only ten of the retiring units are more expensive to operate that the all-in market price; this

[3] EIA (2013) "Annual Energy Outlook 2012." Retrieved from http://www.eia.gov/forecasts/aeo/data.cfm

suggests that decisions about retirements are being made on the basis of expected future environmental costs.[4]

Figure 2 plots the future costs of each coal plant, including required environmental controls, against the same current capacity factors (shown as blue circles). Environmental controls assumed necessary for regulatory compliance in Figure 2 are activated carbon injection (ACI) in 2016, baghouses in 2018, selective catalytic reduction (SCR) in 2019, recirculating cooling systems in 2019, effluent controls in 2019, coal ash controls in 2021, and flue gas desulphurization (FGD) in 2025. Control costs are assigned to only those units that are currently uncontrolled. The Synapse mid CO_2 price case (starting at $20.00/ton in 2020, and rising to $69.50/ton in 2042) is also assumed.[5] Units currently announced for retirement are again outlined in red. Note that the energy-only and all-in market prices in this figure have also been adjusted to include the Synapse mid CO_2 price case.

Figure 2. Projected net present value of coal units assuming environmental retrofits, compared to typical national market electricity prices, 2013-2042



Note: The y-axis in Figure 2 is truncated at $250/MWh; some units with capacity factors of 15 percent or less have net present value costs that are higher than $250/MWh when assuming new environmental controls.

[4] The number of units described as uneconomic in the text of this report is based on comparisons to regionally specific market prices, and therefore may not correspond exactly to unit placement above or below the curves representing illustrative national market prices in Figures 1 and 2.

[5] Synapse Energy Economics, October 2012, "2012 Carbon Dioxide Price Forecast."

After accounting for environmental retrofit costs, just 137 units are economic compared to the all-in market price of electricity, and only 28 units are economic compared to the lower, energy-only market price.[6] Interestingly, announced retirements tend to confirm Synapse's results. Out of 201 coal units with announced retirement dates (circled in red), only three units are identified by CAVT as being "economic" compared to the all-in market price in Figure 2.

Of course, as numerous coal units retire, there will likely be changes in the markets for coal and natural gas that will influence the comparative economics of the remaining units. The analysis presented in this paper should be interpreted as a snapshot based on current market conditions and expectations

3.2. Testing the Effects of Key Assumptions

The forecasted economics of operating coal units compared to purchasing wholesale market power depend on underlying CAVT modeling assumptions regarding the costs of market replacements and environmental controls. To investigate the impact of differing assumptions on the results of our analysis, we tested the model's sensitivity to a range of natural gas prices and environmental retrofit scenarios.

In this section we present four cases representing the extremes of this analysis: high gas prices with lenient environmental control assumptions; high gas prices with strict environmental control assumptions; low gas prices with lenient environmental control assumptions; and low gas prices with strict environmental control assumptions. (See Appendix A for detailed descriptions of these assumptions.) While natural gas prices used in the energy-only and all-in market prices shown in Figure 1 and 2 are U.S. averages (and, therefore, only representative), in CAVT's unit-specific statistical analysis we compare each plant's economics to regional market prices based on AEO's regional natural gas price projections.

Table 1 displays summary results for all four sensitivities in terms of the amount in GW and percentage of total coal capacity that is uneconomic compared to both energy-only and all-in market purchases. In general, lower gas prices and more stringent environmental control requirements result in more coal capacity rendered uneconomic. Conversely, in scenarios with high gas prices and less stringent environmental control requirements, less coal capacity is uneconomic.

When comparing coal to energy-only purchases (see the left side of Table 1), as much as 306 GW of capacity—or 98 percent of total U.S. coal capacity—is found to be uneconomic in the strict environmental retrofit and low natural gas price case, compared to 192 GW in the lenient environmental retrofit and high natural gas price case.

[6] The number of units described as uneconomic in the text of this report is based on comparisons to regionally specific market prices, and therefore may not correspond exactly to unit placement above or below the curves representing illustrative national market prices in Figures 1 and 2.

Table 1. Uneconomic U.S. coal capacity compared to market purchases: mid-cases and sensitivities

Uneconomic Coal Capacity Compared to Energy-Only Purchases (GW)

		Environmental Retrofit		
		Lenient	**Mid**	**Strict**
Natural Gas Price	**High**	192 (62%)		292 (94%)
	Mid		**295 (95%)**	
	Low	254 (82%)		306 (98%)

Uneconomic Coal Capacity Compared to All-In Purchases (GW)

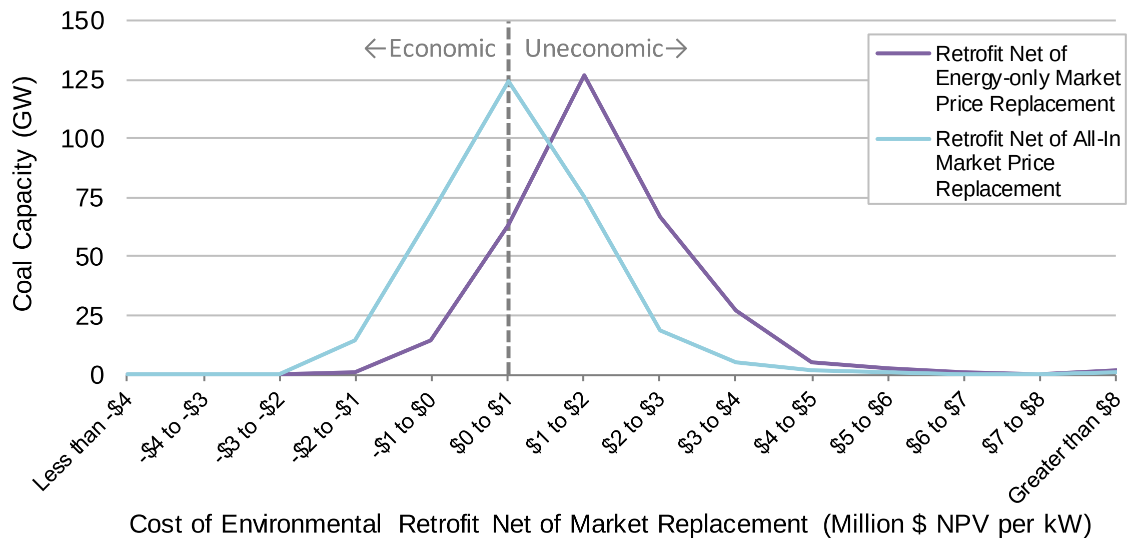
		Environmental Retrofit		
		Lenient	**Mid**	**Strict**
Natural Gas Price	**High**	63 (20%)		230 (74%)
	Mid		**228 (73%)**	
	Low	101 (33%)		274 (88%)

Note: Percentages indicate the share of the capacity of the uneconomic units compared to total coal capacity

When comparing coal to the higher costs of all-in market purchases (see the right side of Table 1), as much as 274 GW of coal is found to be uneconomic in the strict environmental retrofit and low natural gas price case, compared to 63 GW in the lenient environmental retrofit and high natural gas price case.

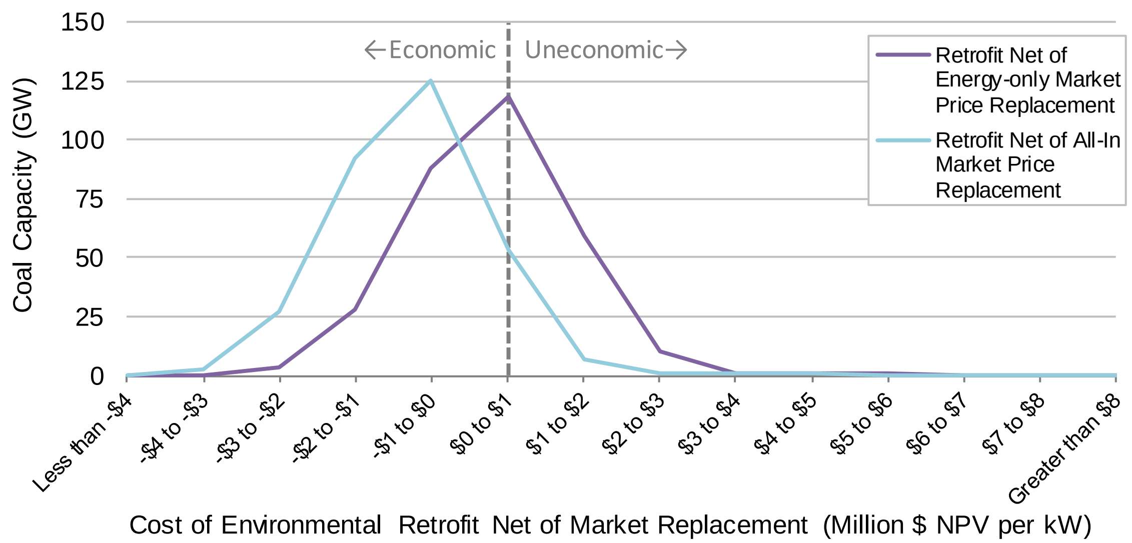
Figure 3 through Figure 7 are histograms of the economic viability of coal capacity compared to market purchases under the mid case scenario and the four sensitivities shown in Table 1. These figures sort coal units into “bins” by net costs (that is, their projected costs with environmental retrofits less the cost of market purchases of the same amount of generation in net present value terms). The dashed vertical line shows the dividing point between units that are economic (to the left) and those that are uneconomic (to the right).

Figure 3. Coal economics sensitivity: mid gas, mid retrofit case



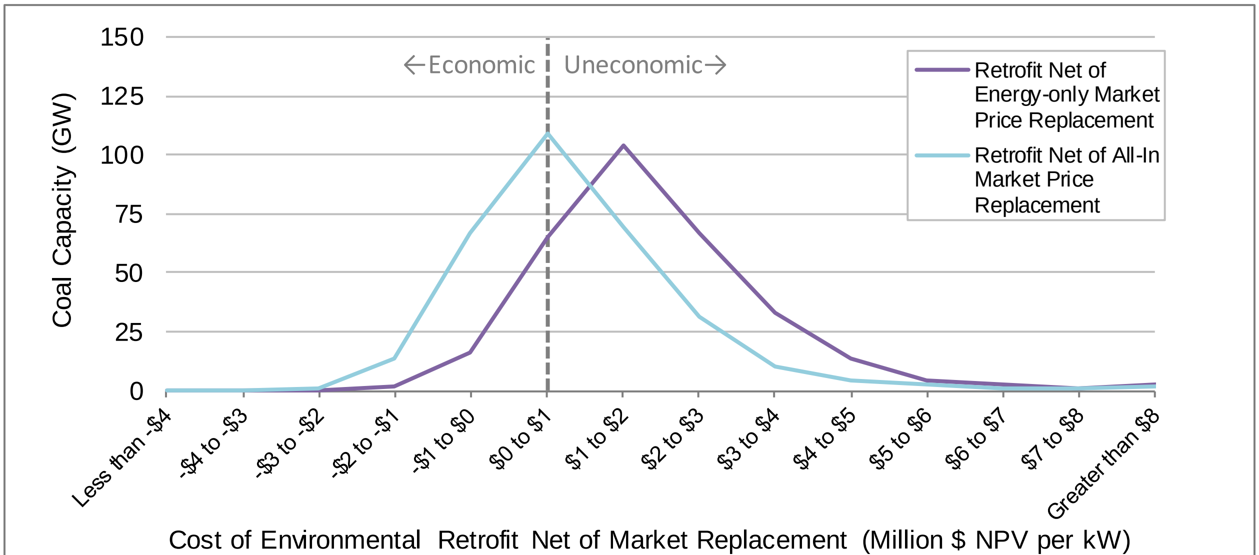
Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	860 (97%)	751 (85%)
Capacity (GW)	295 (95%)	228 (73%)
Generation (TWh)	1,501 (94%)	1,122 (70%)

Figure 4. Coal economics sensitivity: high gas, lenient retrofit case



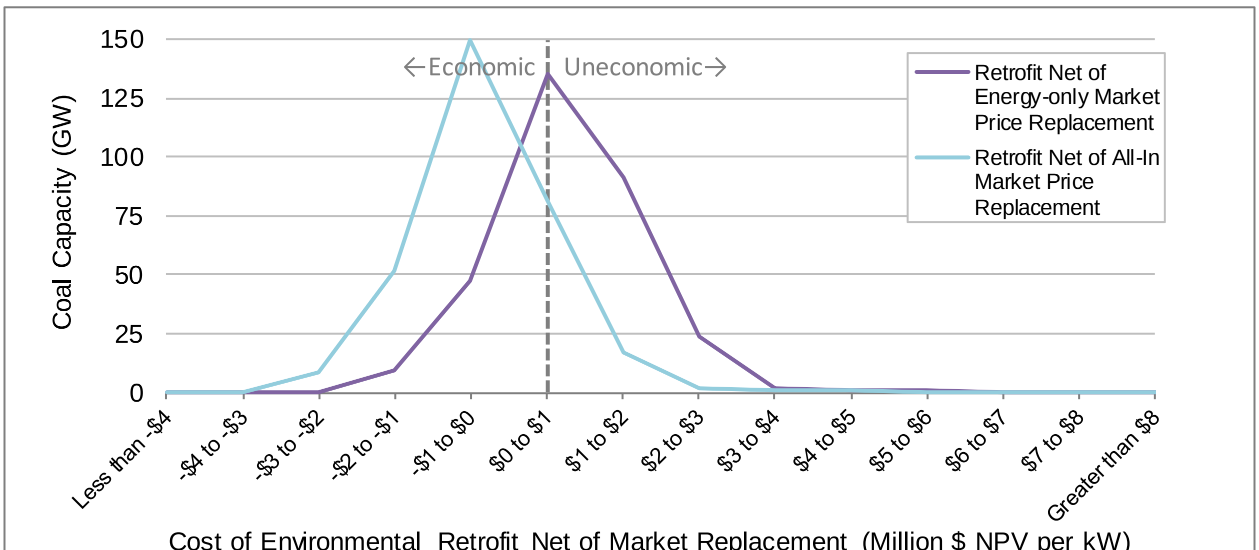
Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	676 (76%)	364 (41%)
Capacity (GW)	192 (62%)	63 (20%)
Generation (TWh)	883 (55%)	244 (15%)

Figure 5. Coal economics sensitivity: high gas, strict retrofit case



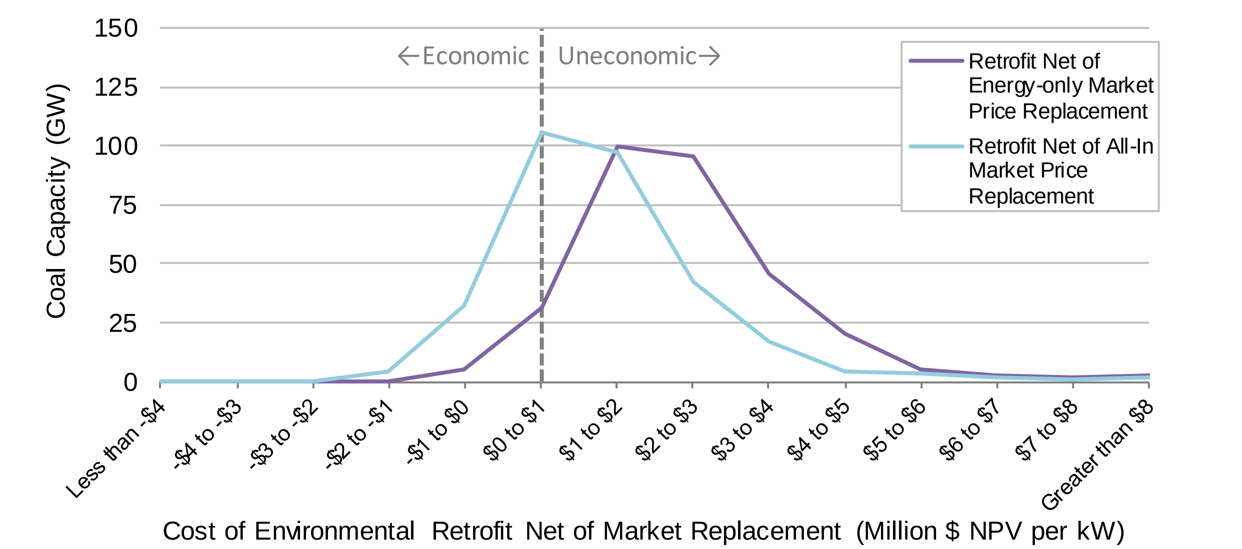
Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	856 (96%)	758 (85%)
Capacity (GW)	292 (94%)	230 (74%)
Generation (TWh)	1,484 (93%)	1,125 (70%)

Figure 6. Coal economics sensitivity: low gas, lenient retrofit case



Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	780 (88%)	468 (53%)
Capacity (GW)	254 (82%)	101 (33%)
Generation (TWh)	1,244 (78%)	438 (27%)

Figure 7. Coal economics sensitivity: low gas, strict retrofit case



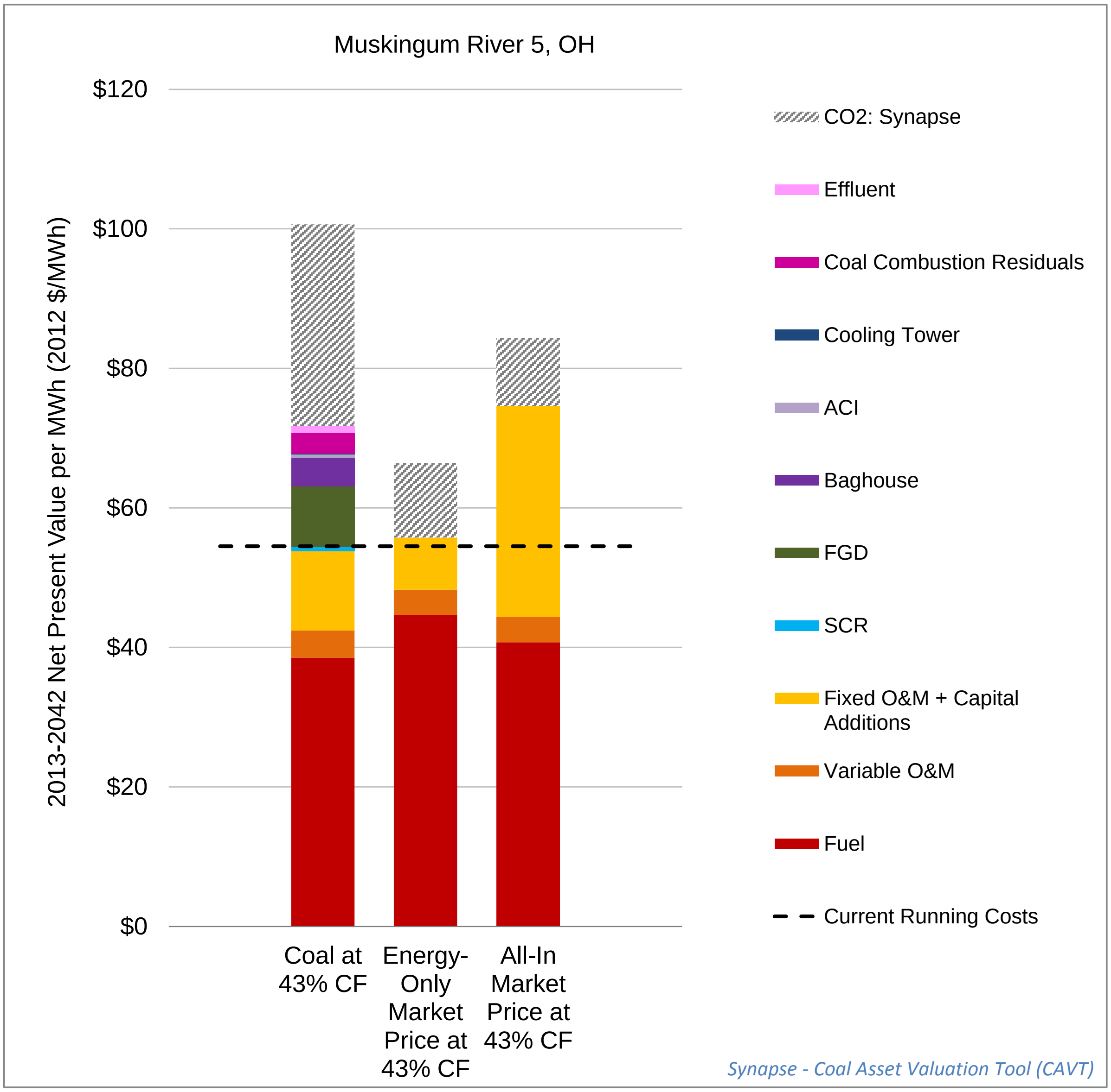
Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	881 (99%)	829 (93%)
Capacity (GW)	306 (98%)	274 (88%)
Generation (TWh)	1,573 (98%)	1,388 (87%)

In addition to the four sensitivities described above, Synapse ran a “very high” natural gas price scenario in which the 2042 nationwide average natural gas price is 30 percent above the reference case natural gas price. (The “high” natural gas price sensitivity is approximately 10 percent above the reference case natural gas price in 2042.) Our analysis shows that, even assuming “very high” natural gas prices, a significant portion of U.S. coal capacity is at risk for retirement—as much as 85 percent when comparing coal unit economics to energy-only market prices, and assuming strict environmental control requirements. See Appendix B of this report for a discussion of the “very high” gas price sensitivity analysis.

4. Muskingum River 5: A Case Study in Uneconomic Coal

In addition to national-level analyses, CAVT can provide detailed cost analyses, and comparisons to market costs, for individual coal units. For example, Muskingum River 5—a 585 MW coal plant in Beverly, Ohio, built in 1968—provides a useful illustration of the comparative economics of an aging coal plant now slated for retirement in 2015 (see Figure 8).[7]

Figure 8. Muskingum River 5's current and future costs as compared to market prices



[7] American Electric Power (2013) "AEP Expects To Retire 585-Megawatt Coal-Fueled Unit In Ohio." [Press Release]. Retrieved from https://www.aep.com/newsroom/newsreleases/?id=1820

Using the CAVT model, we estimate the net present value of operating Muskingum River 5 from 2013 through 2042 at its 2012 capacity factor of 43 percent. The net present value of its current operating costs is $54 per MWh (shown as a horizontal dashed line). These costs include fuel, variable operations and maintenance (O&M), fixed O&M, and expected capital improvements not related to environmental controls; importantly, the current operating costs depicted in this report also include the cost of running existing environmental controls. In the case of Muskingum River 5, we model the cost of operating its existing SCR.

With the cost of installing and operating expected future environmental controls included, Muskingum River 5's operating costs nearly double—reaching $101 per MWh in net present value. The additional environmental controls assumed necessary for regulatory compliance at Muskingum River 5 are an ACI in 2016, a baghouse in 2018, impingement controls and a recirculating cooling system in 2019, effluent controls in 2019, coal ash controls in 2021, and an FGD in 2025.[8] The Synapse mid CO_2 price case is also assumed.

Figure 8 compares Muskingum River 5's current and future operating costs to the cost of purchasing the same amount of electricity generated by the unit (2.3 million MWh, based on an average of 2010 to 2012 generation) at both the energy-only and all-in market prices.[9] The cost of market purchases of electricity at the energy-only price is $66 per MWh, including the cost of compliance with a national carbon price; the all-in market price is $84 per MWh.

The CAVT analysis clearly shows that continued operation of Muskingum River 5 is uneconomic in comparison to these market alternatives. Muskingum River's owners agree. On July 11, 2013, American Electric Power announced the unit's retirement, citing (among other concerns) the "cost of compliance with environmental regulations and current market conditions."[10]

[8] Control costs are assigned to only those units which are currently uncontrolled.

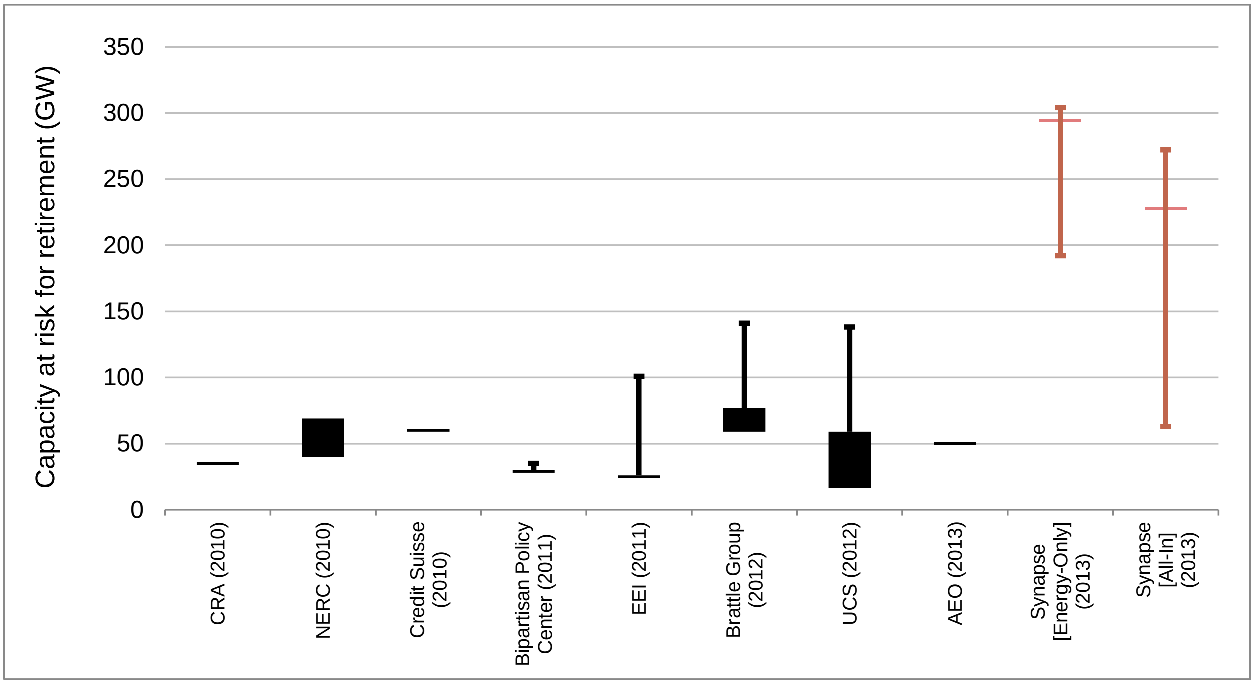
[9] The middle column depicts an energy-only market price based on the operating costs of an existing natural gas combined-cycle plant. The right column depicts an all-in market price based on the cost of constructing and operating a new natural gas combined-cycle plant. In this figure, natural gas prices are assumed to be based on a national average price of $4.42/MMBtu, increasing by an annual average rate of 2.24 percent. These market prices include the cost of the Synapse mid CO_2 price case, as applied to natural gas combined-cycle units.

[10] American Electric Power (2013) "AEP Expects To Retire 585-Megawatt Coal-Fueled Unit In Ohio." [Press Release]. Retrieved from https://www.aep.com/newsroom/newsreleases/?id=1820

5. A REVIEW OF RECENT RETIREMENT RISK PROJECTIONS

Numerous industry groups, environmental advocates, and government agencies have published estimates of the U.S. coal capacity at risk of retirement. Figure 9 shows just a few of the most commonly cited coal retirement risk studies published from 2010 through 2013. These studies use a range of assumptions regarding environmental regulations, natural gas prices, and carbon prices. Boxes and horizontal lines indicate the range of results from each study's reference case, while the vertical whiskers indicate the high and low sensitivities.

Figure 9. Comparison of coal retirement projection ranges



Sources: See Table 2.

Note: Each projection uses different assumptions for environmental retrofits, natural gas prices, and CO_2 prices.

Synapse's estimates are higher than the other projections' sensitivities. In general, this is because Synapse's projections include cost estimates for all expected environmental controls, rather than a subset. For example, costs of cooling, coal ash, and effluent controls are considered in all of the Synapse sensitivities, while these controls are only analyzed in some of the other studies, and often only in the "high" sensitivities. Furthermore, each of Synapse's projections includes a carbon price. In the "mid" case, this price is $20.00 per ton starting in 2020, rising to $69.50 per ton in 2042 (in 2012$). Levelized, this carbon price represents, on average, 26 percent of a potential retrofit's total cost. Only the Edison Electric Institute, Brattle Group, and Union of Concerned Scientist studies include carbon prices in some sensitivities, ranging from $12 to $30 in 2020.

Table 2 describes the assumed environmental controls, carbon prices, and natural gas prices associated with the coal retirement scenario for each study that results in the largest retirement of coal capacity.

Table 2. Environmental controls, carbon price, and natural gas price under highest coal retirement sensitivities

	Most Stringent Control Case	Lowest Gas Case	Source
CRA (2010)	FGD, baghouse, ACI	AEO 2010 Base Case	Charles River Associates (2010) *A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT*. Retrieved from http://crai.com/uploadedFiles/Publications/CRA-Reliability-Assessment-of-EPA%27s-Proposed-Transport-Rule.pdf
NERC (2010)	FGD, SCR, ACI (high cost), recirculating cooling (high cost), CCR (high cost)	Developed by EVA for NERC (~$6-8/MMBtu)	North American Electric Reliability Corporation (2010) *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.* Retrieved from http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf
Credit Suisse (2010)	Eastern Coal: FGD, SCR, ACI; Western Coal: DSI, SNCR, baghouse, ACI	$6.50/MMBtu	Credit Suisse (2010) *Growth from Subtraction*. Retrieved from http://op.bna.com/env.nsf/id/jstn-8actja/$File/suisse.pdf
Bipartisan Policy Center (2011)	SCR, FGD, baghouse for units >300 MW, DSI for units <300 MW, ACI, recirculating cooling for units w/ >35% capacity factor and intake > 500 MGD, dry ash handling	AEO 2010 Base Case minus $1/MMBtu	Bipartisan Policy Center (2011) *Environmental Regulation and Electric System Reliability*. Retrieved from http://bipartisanpolicy.org/sites/default /files/BPC%20Electric%20System%20Reliability.pdf
EEI (2011)	Wet or dry FGD, SCR, baghouse, ACI, recirculating cooling, dry ash handling (subtitle C), $25/ton CO_2 price starting in 2017 (escalates by 5% per year)	EPA IPM 4.10	Edison Electric Institute (2011) *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*. Retrieved from http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf
Brattle Group (2012)	WECC: DSI, SCR, DSI, baghouse, and ACI on all units, and $30/ton CO_2 price starting in 2020 Non-WECC: DSI, SCR, baghouse, and ACI on units < 200 MW; wet FGD, SCR, baghouse, and ACI on units >= 200 MW, $30/ton CO_2 price starting in 2020	AEO 2012 Base Case minus $1/MMBtu	Brattle Group (2012) *Potential Coal Plant Retirements: 2012 Update*. Retrieved from http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf
UCS (2012)	FGD, SCR, baghouse, ACI	AEO 2012 Base Case w/ 25% decrease	Union of Concerned Scientists (2012) *Ripe for Retirement: The Case for Closing America's Costliest Coal Plants.* Retrieved from http://www.ucsusa.org/assets/documents/clean_energy/Ripe-for-Retirement-Full-Report.pdf
AEO (2013)	ACI, baghouse, +3% to coal capital representing uncertainty of future GHG regulation	AEO 2013 Base Case	U.S. Energy Information Administration (2013) *Annual Energy Outlook 2013*. Retrieved from http://www.eia.gov/forecasts/aeo/pdf/0383%282013%29.pdf
Synapse [Energy-Only] (2013)	FGD, SCR, baghouse, ACI, impingement controls and recirculating cooling on units with intakes >125 MGD, CCR, effluent, Synapse Mid CO_2 price	AEO 2012 Low Estimated Ultimate Recovery Case	
Synapse [All-In] (2013)	FGD, SCR, baghouse, ACI, impingement controls and recirculating cooling on units with intakes >125 MGD, CCR, effluent, Synapse Mid CO_2 price	AEO 2012 Low Estimated Ultimate Recovery Case	

APPENDIX A: METHODOLOGY, DATA SOURCES, AND ASSUMPTIONS

A.1 CAVT Methodology

Synapse's Coal Asset Valuation Tool (CAVT) is a spreadsheet-based database and model that aggregates publicly available data (such as capacity, generated power, and heat rate) on non-cogenerating coal units and combines this with publicly available cost methodologies to calculate the cost of complying with environmental regulations. Compliance technologies include FGD, SCR, ACI, baghouse, recirculating cooling, coal combustion residual controls, effluent controls, and carbon prices.

Capital, operating, and maintenance costs of each new environmental control are added to each unit's expected operating costs without additional environmental controls (including unit-specific fixed and variable operating and maintenance costs, coal fuel costs, and fixed and variable operating and maintenance costs associated with existing environmental controls) beginning in the year the control is assumed to come into effect. These dollar-per-MWh costs are then multiplied by the unit's assumed generation in each year to determine total dollars spent on plant operations and capital in each year from 2013 through 2042. The net present value of each unit's lifetime cost is then calculated using a 4.71 percent real discount rate. A similar calculation is performed for both the energy-only market price and the all-in market price (using the cost of operating an existing natural gas-fired combined cycle unit and the cost of constructing and operating a new natural gas-fired combined cycle unit, respectively). The "future" coal unit cost is then compared with the two market prices to determine each unit's individual economic viability.

A.2 Data Sources

Source data for coal unit characteristics include the U.S. Energy Information Agency's Form 860[11] and Form 923,[12] and the U.S. Environmental Protection Agency's (EPA's) Air Markets Dataset.[13]

Market price data are developed using the U.S. Energy Information Agency's Annual Energy Outlook 2012 Electricity Market Module Assumptions.[14] See the "Natural Gas Forecast" section, below, for more information.

[11] U.S. Energy Information Agency (2013) *Form EIA-860 detailed data*. Retrieved from http://www.eia.gov/electricity/data/eia860/index.html

[12] U.S. Energy Information Agency (2013) *Form EIA-923 detailed data*. Retrieved from http://www.eia.gov/electricity/data/eia923/

[13] U.S. Environmental Protection Agency (2012) *Air Markets Program Data.* Retrieved from http://ampd.epa.gov/ampd/

[14] U.S. Energy Information Agency (2012) AEO 2012 Electricity Market Module. Retrieved from http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf

Cost methodologies for environmental controls are based on Sargent & Lundy costs developed as inputs for EPA's assumptions in their version of ICF's Integrated Planning Model (IPM) v.4.10, technical documentation for the proposed 316(b) rule, and analysis of cost compliance with the Resource Conservation and Recovery Act, among other sources. See Table 4, below, for more detailed citations.

A.3 Assumptions

Table 3 presents the underlying assumptions used in this report regarding natural gas prices and environmental control requirements. Sections 3.1 and 4 are based on the "mid" natural gas price and "mid" environmental retrofit assumptions. Section 3.2 presents four combinations of the high and low natural gas prices, and lenient and strict retrofit assumptions. Appendix B presents a "very high" gas sensitivity.

Table 3. Environmental retrofit and natural gas assumptions

Natural Gas Price	**Very High**	Natural gas prices grow at 130% of the AEO 2012 Reference Case rate of change
	High	Natural gas prices grow at the AEO 2012 Low Estimated Ultimate Recovery Case rate of change
	Mid	Natural gas prices grow at the AEO 2012 Reference Case rate of change
	Low	Natural gas prices grow at the AEO 2012 High Estimated Ultimate Recovery Case rate of change
Environmental Control Requirements	**Strict**	FGD, SCR, Baghouse, ACI, Impingement Controls and Recirculating Cooling on units with intakes > 125 MGD, Coal Combustion Residual (Subtitle C), Effluent Regulatory Option "4a," "Synapse Mid" CO_2 Price
	Mid	FGD, SCR, Baghouse, ACI, Impingement Controls and Recirculating Cooling on units with intakes > 125 MGD, Coal Combustion Residual (Subtitle D), Effluent Regulatory Option "3," "Synapse Mid" CO_2 Price
	Lenient	Baghouse, ACI, Impingement Controls, Effluent Regulatory Option "3a," "Synapse Low" CO_2 Price

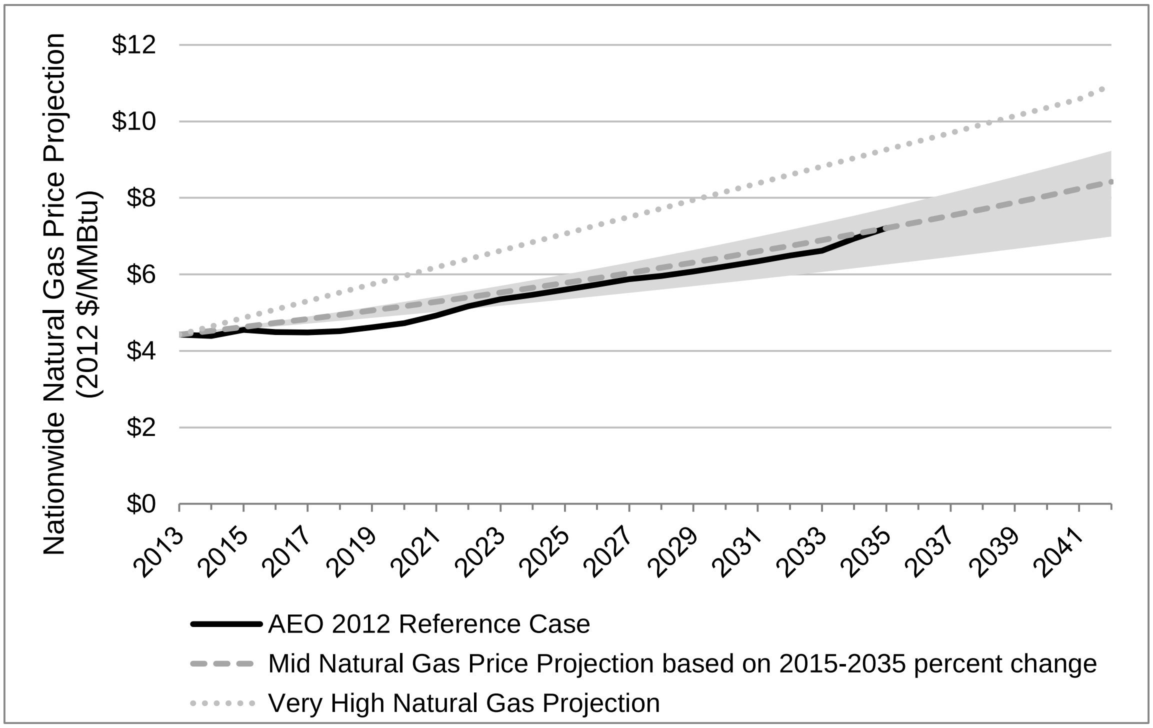
Natural Gas Forecast

CAVT uses regional natural gas price data from the EIA's 2012 Annual Energy Outlook to inform projections of future natural gas price changes.[15] Our mid natural gas prices are the EIA's 2013 reference case price escalated over time using the EIA's 2012-2035 percent change in its reference case natural gas prices. Figure 10 shows the EIA reference case forecast and the mid natural gas price used in this report, as well as the natural gas price sensitivities (shown as a gray wedge). Our high and low natural

[15] EIA (2012) *2012 Annual Energy Outlook*, supplemental tables 11-20. Retrieved from http://www.eia.gov/forecasts/archive/aeo12/data.cfm

gas price sensitivities are estimated using the same starting price and the rates of change used in EIA's 2012-2035 Low and High Estimated Ultimate Recovery Cases, respectively.[16] Our "very high" natural gas price was calculated by linearly interpolating between the EIA's 2013 reference case price and 130 percent of the mid natural gas price projected for 2042.

Figure 10. Natural gas price projections



Note: The low and high natural gas price projections used in the sensitivity analyses are shown as the lower and upper edges of the shaded area. AEO 2012 only estimates prices out to 2035; the CAVT levelization is a 30-year period through 2042.

Environmental Control Requirement Scenarios

CAVT models the costs and year of implementation of a number of common environmental controls (see Table 4). For the purposes of this analysis, we assume that each environmental control will be implemented in the years indicated in Table 4 at every coal unit that does not currently have it. Many units may become controlled before these dates, while other plants may obtain extensions that allow them to continue operating without controls after these dates. Control requirement assumptions are representative. Each coal unit is a unique case—some units may not require the level of retrofit CAVT assumes, while other units may require more extensive retrofits. The choice of environmental control requirements and dates of implementation are Synapse internal assumptions, based on our own judgment; the data sources for the environmental control cost assumptions used in CAVT are shown in Table 4.

[16] Ibid.

Table 4. Environmental control requirement assumptions

Environmental Control	Control Requirement Year: *Lenient*	*Mid*	*Strict*	Source of Environmental Control Cost Data
Flue Gas Desulphurization (FGD)[17]	n/a	2025	2018	Sargent & Lundy. (2010) *IPM Model – Revisions to Cost and Performance for APC Technologies: Wet FGD Cost Development Methodology*. Retrieved from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix51A.pdf
Selective Catalytic Reduction (SCR)	n/a	2019	2019	Sargent & Lundy (2010) *IPM Model – Revisions to Cost and Performance for APC Technologies: SCR Cost Development Methodology*. Retrieved from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52A.pdf
Baghouse	2018	2018	2018	Sargent & Lundy (2011) *IPM Model – Revisions to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology*. Reference no longer available online.
Activated Carbon Injection (ACI)	2016	2016	2015	Sargent & Lundy (2011) *IPM Model – Revisions to Cost and Performance for APC Technologies: Mercury Cost Development Methodology*. Reference no longer available online.
Cooling	2021 (Impingement Controls)	2019 (Impingement Controls, Recirc. cooling for units with >125 MGD intake)	2017 (Impingement Controls, Recirc. cooling for units with >125 MGD intake)	U.S. Environmental Protection Agency (2011) *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*. Retrieved from http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/technicaldevelopment.pdf
Coal Combustion Residuals (CCR)	2023 (Subtitle D)	2021 (Subtitle D)	2019 (Subtitle C)	Electric Power Research Institute (2010) *Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act*. Retrieved from http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020557
Effluent	2021 (EPA regulatory option 3a)	2019 (EPA regulatory option 3)	2017 (EPA regulatory option 4a)	U.S. Environmental Protection Agency (2013) *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. Retrieved from http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_TDD_Proposed-rule_2013.pdf
Carbon Price (RGGI)	RGGI prices used through 2019 for coal units in RGGI states			Regional Greenhouse Gas Initiative (2013) *Regional Greenhouse Gas Initiative Summary of Model Rule Changes*. Retrieved from http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_Summary.pdf
Carbon Price (Synapse)	Synapse "Low" Carbon price beginning in 2020	Synapse "Mid" Carbon price beginning in 2020	Synapse "Mid" Carbon price beginning in 2020	Synapse Energy Economics (2012) 2012 *Carbon Dioxide Price Forecast*. Retrieved from http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf

[17] The costs of installing and operating Dry Sorbent Injection is also modeled by CAVT. We did not include it in this analysis because this technology is unlikely to remove sulfur dioxide to the level required by upcoming environmental regulations.

APPENDIX B: "VERY HIGH" NATURAL GAS PRICE SENSITIVITY

In addition to the four sensitivities described in section 3.2 of this report, Synapse ran a "very high" natural gas price scenario in which the 2042 nationwide average natural gas price is 30 percent above the reference case natural gas price. (The "high" natural gas price sensitivity is approximately 10 percent above the reference case natural gas price in 2042; see Appendix A for more details.) Table 5 reports the amount of coal capacity retiring in this very high gas price scenario compared to the other sensitivities.

Table 5. "Very high" gas sensitivity compared to other sensitivities and Synapse's mid-case

Uneconomic Coal Capacity Compared to Energy-Only Purchases (GW)

		Environmental Retrofit		
		Lenient	Mid	Strict
Natural Gas Price	Very High	130 (42%)		264 (85%)
	High	192 (62%)		292 (94%)
	Mid		**295 (95%)**	
	Low	254 (82%)		306 (98%)

Uneconomic Coal Capacity Compared to All-In Purchases (GW)

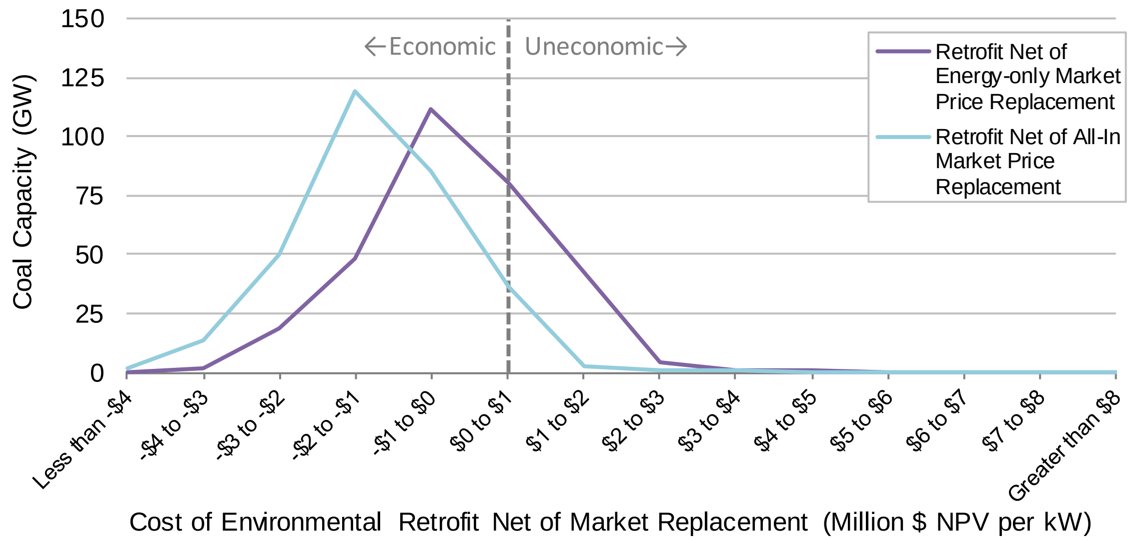
		Environmental Retrofit		
		Lenient	Mid	Strict
Natural Gas Price	Very High	41 (13%)		180 (58%)
	High	63 (20%)		230 (74%)
	Mid		**228 (73%)**	
	Low	101 (33%)		274 (88%)

Note: Percentages indicate the share of the capacity of the uneconomic units compared to total coal capacity

Table 5 demonstrates that, even assuming "very high" natural gas prices, a significant portion of U.S. coal capacity is at risk for retirement. When comparing coal to energy-only purchases (see the left side of Table 5), 42 percent of coal capacity is estimated to retire assuming lenient environmental retrofit requirements, and 85 percent is estimated to retire assuming strict requirements. When comparing coal to all-in market purchases (see the right side of Table 5), 13 percent is estimated to retire assuming lenient environmental retrofit requirements, and 58 percent is estimated to retire assuming strict requirements.

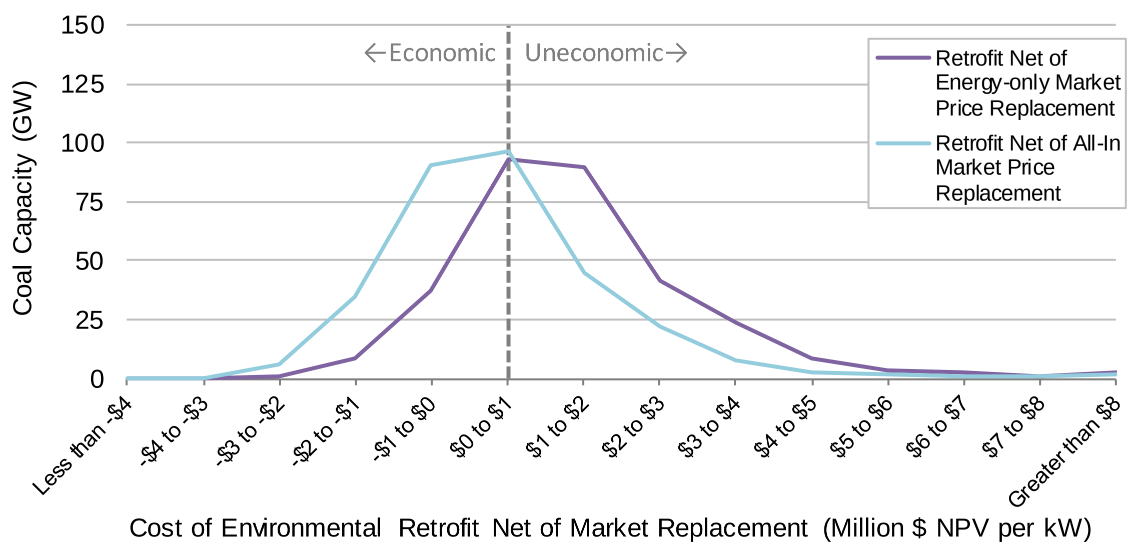
Figure 11 and Figure 12 are histograms of the economic viability of coal capacity compared to market purchases under the very high gas sensitivity and the two environmental retrofit sensitivities. These figures sort coal units into "bins" by net costs (that is, their future costs with environmental retrofits less the cost of market purchases of the same amount of generation in net present value terms). The dashed vertical line shows the dividing point between units that are economic (to the left) and those that are uneconomic (to the right).

Figure 11. Coal economics sensitivity: very high gas, lenient retrofit case



Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	540 (61%)	285 (32%)
Capacity (GW)	130 (42%)	41 (13%)
Generation (TWh)	543 (34%)	146 (9%)

Figure 12. Coal economics sensitivity: very high gas, strict retrofit case



Percent of Coal Fleet Rendered Uneconomic	Cost of Environmental Retrofit Net of Energy-only Market Price Replacement	Cost of Environmental Retrofit Net of All-In Market Price Replacement
Number of Units	809 (91%)	671 (76%)
Capacity (GW)	264 (85%)	180 (58%)
Generation (TWh)	1,308 (82%)	847 (53%)