CRA Insights:
Energy

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The growing risks of regulated coal ownership

Strategies to assess your coal position and maximize its value

Several weeks ago, regulators in West Virginia asked two of FirstEnergy's subsidiaries to explain why buying a merchant coal plant was the least cost option for meeting future supply needs. Both entities, Monongahela Power and Potomac Edison, argued in their resource plans that modeling showed that the purchase of an efficient coal unit resulted in the lowest expected cost for their portfolios. However, even in one of the most coal-dominant states in the nation, regulators questioned whether natural gas and renewable options were properly considered, sending a clear signal that coal owners across the country must carefully consider how they value their coal fleet in light of the alternatives.

A wave of "economic" coal retirements

Over the last few years, low natural gas prices have accelerated the shift away from coal in the US power sector (see Figure 1) that, until recently, had been driven more by environmental regulations. With low natural gas price conditions, coal resources traditionally used as baseload generators have struggled to maintain capacity factors above 50% (see Figure 2). This reduced operation, even as the inefficient, uncontrolled plants within the coal fleet have retired, is driving questions about coal's future economic viability.

Figure 1: US power generation by fuel type

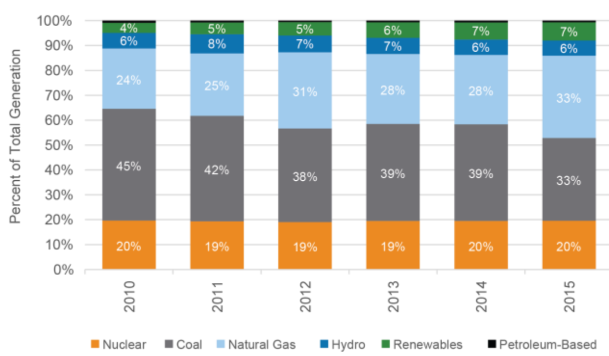
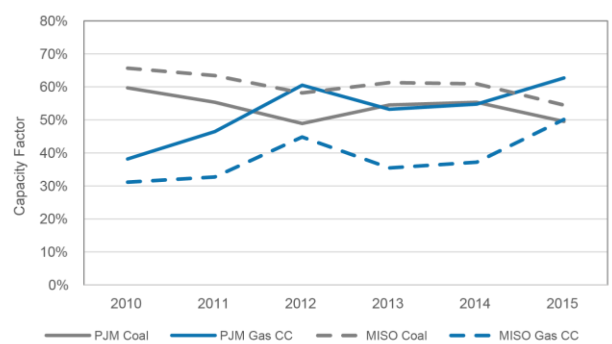


Figure 2: Coal and combined cycle capacity factors in PJM and MISO



Source: CRA analysis and US Energy Information Administration

Coal plant retirement decisions are typically made when the cost of environmental compliance (capital costs and fixed and variable operating costs) outweighs the benefits of operating the facility. Most recently, the EPA's Mercury and Air Toxics Standards (MATS) program, along with low gas prices and flattening demand, drove a large number of retirements as a result of emission standards that required substantial capital investment for many coal owners. However, retirement announcements are now being made for coal plants that are well-controlled for emissions, suggesting that cost-competitiveness is no longer closely tied to environmental regulations. As shown in Figure 3, past retirements were made up of plants that were not controlled for emissions, while announcements for future shutdowns include plants that CRA believes to be well-controlled for SO_2, NOx, and mercury. These retirement candidates include facilities of all sizes and heat rates.[1] While many of these plants are merchant units struggling to stay afloat in competitive power markets, a large number are owned by regulated utilities.

Figure 3: Coal retirements according to heat rate and environmental controls

Source: CRA analysis

In competitive wholesale markets (notably MISO and PJM), the economic valuation of regulated coal capacity is complicated. While incorporated in rate base, coal plants are still expected to achieve positive margins for their owners in the power markets. Profitability in the wholesale energy market, however, is difficult to achieve for coal plants when combined cycles have lower variable costs, as they do now with

1 Note that there were a few additional retirements of units with heat rates above 13,000 Btu/kWh that are not shown in Figure 3. The majority of these units were uncontrolled, and the capacity of all these units was below 100 MW.

gas prices hovering around $2/MMBtu. To complicate matters, coal plants often have fuel delivery minimums or stockpile management issues and cannot physically cycle up and down on a daily basis. Therefore, they often consider must-run offers to the energy market, driving energy margins negative at times.

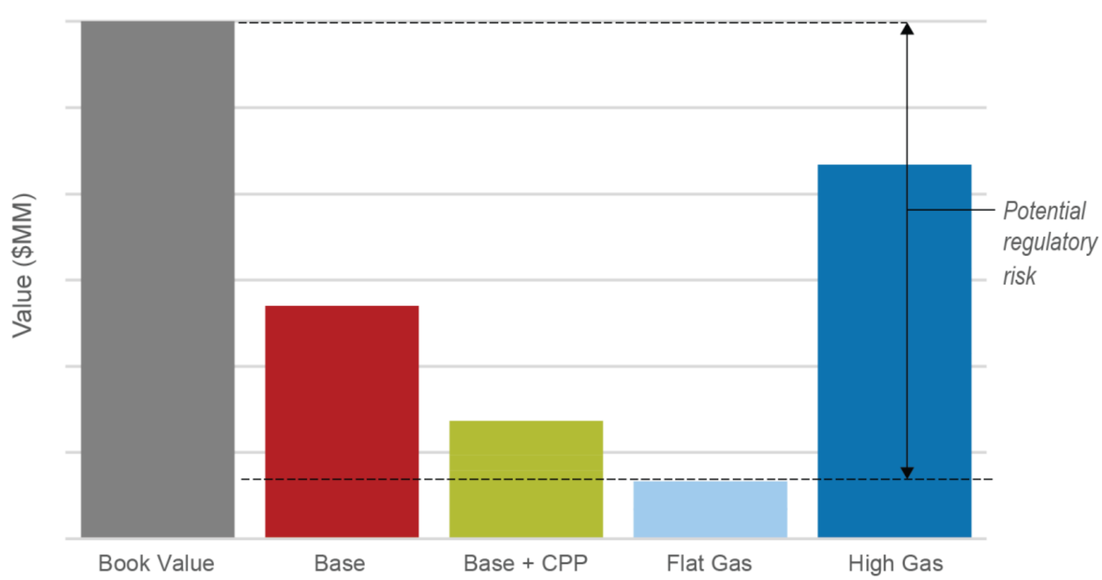
This might lead certain plants to temporarily mothball and may raise prudency questions for regulated plants that choose not to. FirstEnergy, for example, recently announced a temporary idling of the 2,500 MW Bruce Mansfield coal-fired power plant in Pennsylvania. This plant has a relatively attractive heat rate and is currently spending environmental-related capital, proving that even the most efficient, controlled coal capacity in the region is subject to difficulties in the market with low gas prices.

Furthermore, the interactions between energy markets and capacity markets are becoming more complex, especially as we observe existing coal and nuclear units requiring higher capacity payments than new build combined cycles in PJM. The traditional Net Cost of New Entry (CONE) benchmark is becoming less meaningful in certain markets, and utilities will need to consider whether it is cheaper to build a new combined cycle plant than to continue operating an existing coal plant.

Market v. book value

Regulators' concerns regarding coal capacity now often relate to economic viability, and more specifically, to the increasing gap between the market and book value of coal units under their jurisdiction. CRA recently analyzed one client's portfolio and revealed a value gap that was between 10% and 20% of the utility's entire market capitalization. Using fundamental projections of long-term fuel and power market dynamics, we calculated the net present value of energy and capacity margins net of fixed and variable operating costs across four distinct scenarios that altered gas prices and considered Clean Power Plan (CPP) implementation (see Figure 4). The analysis illustrated how a merchant buyer would only value this particular portfolio at a fraction of the book value, which incorporates several major environmental retrofit investments made in recent years.

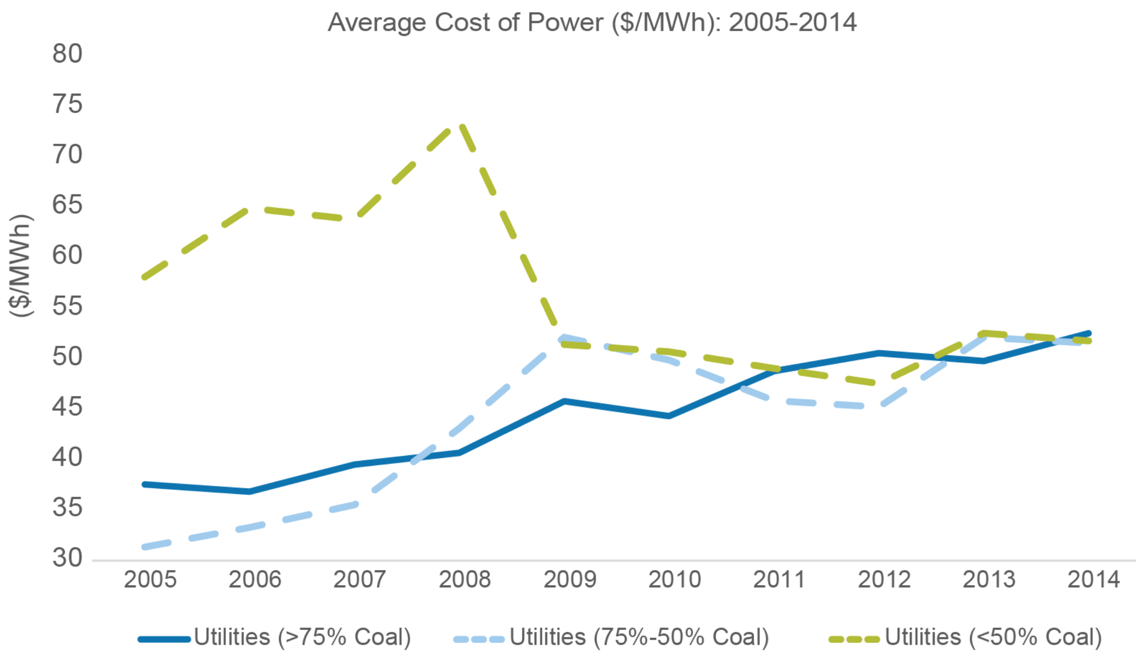
Figure 4: Coal-portfolio book value v. market value



Source: CRA analysis

This situation is not unique. Due to such large capital investment requirements for pollution control and the relatively high cost of coal versus natural gas in recent years, the all-in cost of power for coal-dominated utilities has increased relative to other utilities in recent years (see Figure 5).[2] Where coal utilities enjoyed an advantage in the mid-2000s, they are now equal to or at a disadvantage to more diversified portfolios. The cost impacts for ratepayers are becoming harder to ignore.

Figure 5: Comparison all-in cost of power – different types of coal ownership



Source: CRA analysis

The value of portfolio diversification?

To be sure, coal units create important diversification value for the market and their owners. Based on CRA's analysis, an increase in gas prices to levels between $3/MMBtu and $4/MMBtu would lead many coal units to return to economic baseload operations. On the other hand, sustained lower gas prices will likely raise prudency questions for some utilities. Some executives we speak to believe it is better to strike a deal now to retire or re-power certain plants to burn natural gas and recover most, if not all, stranded costs. The alternative could be a situation where the worst-performing coal plants are effectively idled over the long-term, with certain costs unable to be recovered in rates.

[2] The summary contains 23 investor-owned operating utilities throughout the footprint of MISO states. In categorizing the utilities, we calculated the percentage of "baseload" capacity (coal, nuclear, gas combined cycles, and hydro) that was coal in each individual year and divided the group into three categories (<50% coal, 50-75% coal, >75% coal).

There will always be differences between the market and book value of regulated plants, and there is not a hard rule for when a regulated plant becomes a potential disallowance risk. However, utilities can seek to maximize the value of their portfolio by making the following considerations when assessing their coal position:

- **The size of the value gap.** A merchant market analysis, preferably with stochastics, will help utilities understand the potential size of the difference between market and book value and consider how this may translate into future stranded costs. The potential value gap is unique for all assets and is a function of past investments made in the asset, as well as market drivers such as the delivered coal price, regional renewable penetration, load growth, and regional natural gas prices.
- **Rate competitiveness v. peers.** When a utility's rates are higher than regional peer rates, pressures can arise from regulatory (downward pressure on allowed returns), competitive (increased potential for distributed generation penetration), and customer-driven (potential loss of industrial and commercial loads) forces. A sector-wide rate forecast will illustrate how relative positioning could change in the future. CRA recently ran a peer rate analysis for a utility with relatively high rates that revealed that peer utility rates were likely to rise further as a result of required investments. This information was a consideration in the utility's decision to delay the retirement of a coal plant. CRA's Peer Rate Forecasting Model can forecast rates for all US investor-owned utilities.
- **The benefit of diversification.** While coal assets may currently appear uneconomic, long-term fuel diversity could protect against future spikes in natural gas prices or uncertainty in other power market drivers, such as the capital costs to build new plants, load growth, and technology change. CRA's risk analysis approach quantifies the uncertainty of key cost and reliability drivers and presents simple metrics to evaluate portfolio diversification. For example, a more diverse portfolio might have a higher expected cost, but also a lower standard deviation of costs and a lower risk of a large-scale reliability concern driven by plant outages or fuel unavailability.

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