



White Paper:

Financial Risks of Investments in Coal

AS YOU SOW

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EXECUTIVE SUMMARY

Coal in the United States is at a crisis point that the investment community is just beginning to perceive. In the past year, a spate of industry reports from analysts have detailed the unprecedented risks facing electric utilities that depend on coal-fired generation and the attendant risk to domestic demand for coal.¹ In 2009, coal accounted for 44.5% of this country's electricity generation and 93% of domestic coal was consumed by U.S. power plants. But the nation's aging coal fleet, 60% of which is over 40 years old, needs to be modernized. In the past five years, plans for 153 new coal plants have been cancelled and there is consensus among analysts that a significant portion, possibly 20% or more, of U.S. coal-burning generation could be retired in the very near future. Replacement resources are likely to come from natural gas, solar, wind, and energy efficiency, not new coal.

This historic shift in coal's fortunes stems from a combination of factors, among them:

- Competition from low natural gas prices, which is exerting downward pressure on power prices;
- Capital expenditures for environmental compliance and uncertainty about the cost implications of pending and anticipated environmental mandates;
- Persistently high construction costs;
- Coal price volatility, rising costs for mining, and shifting markets all placing upward pressure on coal prices;
- Improved profitability and policy preferences for solar, wind, and energy efficiency investments; and
- The slow pace of development of viable commercial scale carbon capture and storage for coal plants.

The fundamental change that is undermining coal is the price reversal of coal relative to natural gas, which is in abundant supply for the foreseeable future. With the development of technology to access the large natural gas reserves in the U.S., the price of natural gas has dropped and is expected to stay low for several years.² The impact was felt in 2009 with a drop in coal use in the U.S. electric grid and a concomitant increase in the use of natural gas for generation. As the economy rebounds, if natural gas prices remain competitive there will be a permanent loss of coal's market share in many parts of the country.

According to Deutsche Bank, a key driver of the coal-to-gas switch "is a \$4-6/mmBtu natural gas price due to the major increase in supply coming from unconventional shale gas."³ Energy expert Daniel Yergin writes that estimates of the U.S. natural gas resource base, including shale gas, "are now as high as 2.500 trillion cubic feet," which amounts to "more than a 100-year supply" of natural gas for all uses, from home heating and cooking to petrochemical and electric power production.⁴

The Brattle Group's analysis projects average prices through 2020 under \$6.50 per mmbtu⁵ and the U.S. Energy Information Administration (EIA) foresees gas prices reaching \$6.00 per mmBtu by 2025.⁶ At this price, cleaner burning natural gas is competitive with coal. Given future predictions for relatively flat gas prices, low power prices, and volatility in the price of coal, underutilized gas plants will be called upon to dispatch before coal-fired plants on an increasing basis. Industry analysts M.J. Bradley & Associates and the Analysis Group found that "existing gas units have significant untapped power production potential, which can be expanded during off peak periods without constructing new generation."⁷

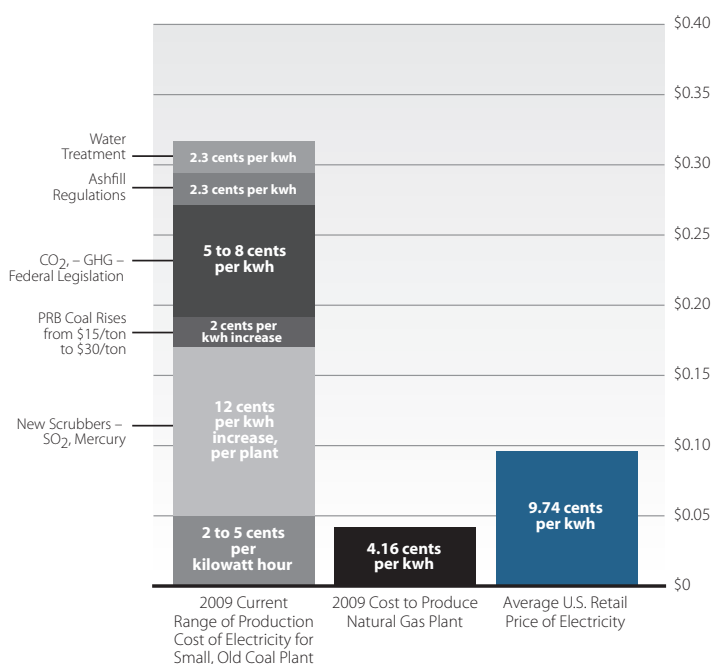
In addition to the risk posed by natural gas, a shifting array of risks related to construction prices, regulatory risks, and policy choices individually diminish coal's usefulness as a fuel source for electric generation. This white paper demonstrates that these factors combine to make current and future investments in coal-dependent utilities and coal mining companies exceedingly risky.

Pension, institutional, and endowment fund sponsors, trustees, board members, and managers need to consider the individual and cumulative impact of these risks and evaluate options to mitigate adverse impacts on portfolio value. We believe that the analysis presented in this white paper requires all investors, but particularly responsible investors concerned with environmental, social, and governance issues, to engage the management of utility companies to find alternatives to coal-based power generation in order to protect shareholder value.

The costs of continued operation for existing coal plants that must comply with recently adopted and pending environmental mandates can be seen in the chart below. Increasingly, coal's competitive advantage is being eroded by the individual and cumulative impact of regulatory and market forces.

Abstract financial models are only one indication of coal's market losses. Results of operations are even more telling. In 2009, many coal-fired plants did not recover their costs – even without the additional expense of new environmental regulations. The *2009 State of the Market Report for PJM*, which includes 13 states in the mid-Atlantic and portions of the Midwest, concludes that “if this result is expected to continue, the retirement of these plants would be an economically rational decision.” Throughout 2010, despite some pickup in the national economy, coal generation repeatedly lost out to other fuels in the electricity marketplace in certain regions of the country. By year's end, utilities reported that coal plants nationwide had lost 10% of their asset value.⁹

Competitive Disadvantage of Existing Coal-Fired Power Plants⁸



At present, the clearest signal that the utility industry acknowledges these risks is the cancellation by public utility commissions and utilities of 153 new coal plants. The plant cancellations amounted to \$243 billion in investment decisions being reversed, or disinvested, from coal in the past four years. In 2010, a growing list of utility announcements carrying the message of existing coal plant closures and plans for new natural gas plants and alternative energy projects continued the trend.

Investment and pension fund fiduciaries, whose duty requires diligent inquiry and prudence in evaluating investment alternatives, must consider the financial implications of these coal exposure risks and factor them into assessments of “risk adjusted returns” for both the electric utility and coal mining sectors. Although markets may not yet fully reflect these risks, due in part to market failure in pricing environmental externality costs, this is certain to change given that “the correlation between environmental performance and financial performance is affected by the content and strength of environmental regulation.”¹⁰ As we document in this white paper, the climate for increasing regulatory compliance in the electric power sector is upon us, whether driven by initiatives of federal and state environmental agencies or by litigation. And this changing climate comes at a time when industry margins are squeezed by competitive prices for natural gas while both capital and operating costs are increasing.

This paper synthesizes the economic case that industry analysts have presented and examines the criteria that investors should use in assessing their exposure to coal risk. Although the coal industry is offering a series of arguments and programmatic actions to bolster its position, nevertheless, its bottom line competitiveness has eroded. How institutional investors react to this change in the coming months and years will help determine the shape of energy investments in the United States in the coming decades. It will also answer the question of whether a rational, stable allocation of capital can be achieved against the backdrop of profound economic, technological, political, and environmental change that is unfolding at global, national, and local levels.

FORWARD

By Andrew Behar
CEO, As You Sow

The central thesis of this white paper is that the transition away from coal to cleaner alternatives is inevitable given the multiple financial risks facing companies dependent on coal. These risks are highly material, singly and combined, and utilities that begin this transition today will be better positioned for success in the future.

The U.S. coal fleet is aging and inefficient. Large capital investments for pollution controls are needed. The next generation of coal plants has been cancelled. The price of coal is rising and low natural gas prices are undercutting profitability. These fundamental facts, presented here, evolved into shareholder resolutions filed by As You Sow and Trillium Asset Management in the spring of 2011 asking coal-burning utilities to prepare a report for investors on the financial risks of continued reliance on coal compared with investments in clean energy and efficiency.

The support for these resolutions demonstrates that investors are becoming aware of the bottom-line risk and want management to address it. Over 31% of FirstEnergy's shareholders, owning \$4.4 billion worth of shares, voted for the As You Sow resolution, an extraordinary level of support for a resolution on the proxy for the first time.

As demonstrated in this white paper, the financial viability of the coal-based business model has been undercut by market forces. Based on multiple analyst reports, commodity projections, existing regulatory requirements, and new pending rules, the financial pressures lead to only one possible solution: transition to cleaner energy sources.

I want to thank The Wallace Global Fund, The Educational Foundation of America and The Carolyn Foundation for their support and also thank the authors and contributors for their energy and detailed analysis of the data and trends are presented in this paper.

As You Sow is a nonprofit organization, founded in 1992, dedicated to increasing corporate environmental and social responsibility. Its Corporate Social Responsibility Program is one of the nation's leading proponents of shareholder engagements providing research and advocacy to catalyze positive change within publicly held companies. <http://www.asyousow.org>

INTRODUCTION

Throughout the 20th century, the coal mining and electric power generation industries have been close allies as they worked together to provide the nation's electricity. For the last five decades they have been stable economic forces, growing at a slow but steady rate and, in most cases, delivering dividends to investors. Yet due to changing economic, political, and environmental conditions the future of these industries requires companies to adapt to a different set of drivers. Failure to shift business strategies in this changing landscape exposes coal-dependent utilities and coal mining companies, as well as their investors, to increasing levels of financial risk and diminished value.

For the purposes of conceptual clarity, the risks discussed in this paper are organized into three broad categories.

1. **The unprecedented level of regulatory uncertainty.** Existing regulations are being more strictly enforced as a result of litigation and the change of administration in Washington. New regulations in the pipeline will impart significant, unpredictable individual and cumulative costs on coal-reliant utilities.
2. **Commodity risk due to low natural gas and power prices and volatile and rising coal prices.** An abundant supply of natural gas in the U.S. and the rapid decline in its price have driven power prices lower nationwide. This market condition is expected to persist for the foreseeable future. The changing nature of domestic coal markets and the prospect of future increases in the price of coal make its uncertainty as an inexpensive fuel for electricity production a new piece of the energy calculus in the United States.
3. **Increasing construction costs.** Global price increases for construction materials due to new power plant construction in China and India have established a new floor for coal price construction at a time when domestic regulatory mandates, the age of the nation's coal fleet, and low power prices are driving decisions to replace the existing fleet of coal plants with other sources of power generation.

This paper discusses the market dynamics and investor actions that are at play globally, nationally, and regionally as our energy infrastructure is remade. Throughout, we show how geological, technological, energy planning, economic, and political factors all play into the assessment of investor risk and rewards from companies that depend on coal.

I. REGULATORY RISKS

Background

Environmental and safety regulation of coal-fired electricity generation and mining activities increasingly requires companies to internalize the cost of pollution and waste discharges to the environment, dangerous workplace practices, and other externalities that were not previously borne by these companies. At each stage, from production to combustion, coal creates pollution and conditions that endanger workers and the public at large.¹¹ Its costs, as seen in the final unit cost of mined coal or electricity produced with coal-fired generation, continue to rise as these previously uncharged practices become costs of production.

Changes in policy and politics proceed, challenging technology and markets to create new business models that are efficient, productive, and profitable. From an investment perspective, coal is in a period of development where the science, geology, policy, politics, technology, and markets are misaligned and profitability is suffering. The ongoing dialogue regarding appropriate and protective standards makes quantifying regulatory risk a moving target. Additional regulations in the pipeline will continue to increase the capital and operating costs for both mining companies and coal-burning utilities.

Table 1: EPA Regulatory Timeline

Regulatory Action	2010	2011	2012	2013	2014	2015	2016	2017
CATR (replacement for CAIR)	CATR public comment	Final CATR			Compliance w. CATR (covers sources in 33 states); Reduce NO _x by 52% and SO ₂ by 71% below 2005 levels			
NO_x	Primary NAAQS		Secondary NAAQS					
SO₂	Primary NAAQS		Secondary NAAQS					
Ozone	Review Ozone NAAQS	Final Non-Attainment Designations			Next Ozone NAAQS review			
Particulates		PM _{2.5} NAAQS revision	PM _{2.5} SIP call	New PM _{2.5} NAAQS designation				
HAPs (Hg)		MACT for HAPs mercury (Hg)	Final MACT for HAPs			Compliance w. MACT begins 3 years after final rule (Possible 1 year extension)		
GHGs (CO₂)	GHG Mandatory Reporting; Tailoring Rule; GHG Permitting Rule; State GHG SIP call	BACT for GHGs required in NSR, PSD, Title V Permits January 2011: State authorities must require BACT in air permits for facilities (newly built or modified) that are already subject to the CAA and with potential to emit 75,000 tons CO ₂ e annually July 2011: All new facilities emitting over 100,000 tons CO ₂ e annually and modified facilities that would increase their CO ₂ e emissions by 75,000 tons annually must obtain construction permits Operating permits required for all sources that emit 100,000 tons CO ₂ e annually Rule for considering biomass in GHG BACT due in July						
Coal Ash (CCR)	Public comment on two options proposed for regulating CCR	Final Rule for CCR		Compliance w. CCR Rule (dry ash conversion, closure of impoundments, groundwater monitoring, etc)				
Cooling Water Intake Structures	EPA commits to set CWA §316(b) technology standards	Proposed standards for CWIS (March)	Final CWIS standards (July)					
Wastewater	EPA commits to set effluent guidelines (per litigation)		Proposed Rule due (July)	Final Rule due (January)				

Electric utilities that rely on coal-fired generation are confronting a series of mandates from the U.S. Environmental Protection Agency (EPA), many of them issued pursuant to court order or in settlement of litigation, that will force a decision whether to invest enormous sums to bring aging coal plants into compliance, replace them with less polluting generating units, or retire them altogether and invest in energy efficiency and renewable energy.

In addition to the recently adopted Greenhouse Gas Permitting Program, other pending EPA actions impacting coal plants include regulation of mercury and other hazardous air pollutants, coal combustion waste, wastewater discharges, and cooling water intake structures. Analysts at Citigroup expect the Obama administration to use the EPA to “regulate noncarbon pollutants in a tougher fashion.”¹² The climate for increasing regulatory compliance is upon us, as evidenced by the EPA’s November 2010 Consent Decree, which will set limits on toxins and heavy metals that coal combustion facilities can release into waterways.¹³

Regulations Affecting Coal-Fired Power Plants

Air:

Coal combustion for electricity is a major contributor to acid rain, smog, climate change, and other pollution. Coal accounts for two-thirds of the sulfur dioxide (SO₂), one-third of the nitrous oxides (NO_x), 34.6% of the carbon dioxide (CO₂), and 50% of the mercury emitted in the U.S and much of the fine particulates (soot) in our air. The Clean Air Act (CAA) protects and improves the nation’s air quality by empowering the EPA to set limits on six “criteria pollutants,” including NO_x, SO₂, ozone, and particulates, and on hazardous air pollutants (HAPs) such as mercury, a powerful neurotoxin. In 2007, the EPA’s authority under the CAA to regulate CO₂ and other greenhouse gases was affirmed by the U.S. Supreme Court.

When the CAA was adopted in 1970, the nation’s older power plants and other stationary pollution sources were exempted on the assumption that these facilities would be retired in a few years. When the CAA was amended in 1977, plants that underwent modifications or upgrades extending their useful life were subject to “New Source Review” (NSR), requiring that plant operators report the modifications to the EPA and obtain construction permits conforming to standards for new facilities.

Although for many years the EPA and the industry ignored NSR, during the Clinton Administration a series of lawsuits were brought for NSR violations. However, the Bush Administration showed little interest in pursuing NSR violations by coal plant operators. One NSR case that did proceed during the Bush years was brought against the W.H. Sammis station owned by Ohio Edison (a subsidiary of FirstEnergy) that had undergone construction projects costing \$136 million, leading the court to conclude that these projects went beyond “routine maintenance” and violated NSR. FirstEnergy ultimately agreed to spend over \$1 billion to reduce pollution from the Sammis plant.¹⁴ More importantly, the court’s analysis implied that every old power plant in the U.S. operating without the necessary pollution controls might be in violation of NSR.

In January 2010 the EPA found, in assessing NSR for its national enforcement priorities, that “investigations and enforcement actions under this national priority confirm that there is widespread noncompliance within the coal-fired electric utilities” and other sectors.¹⁵ Consequently, NSR compliance is now part of the EPA’s National Enforcement Initiative for Fiscal Years 2011-13.¹⁶ Rather than fight NSR actions, one EPA official recently predicted that more facilities will pursue “settlements that involve shutdown of units” and other solutions.¹⁷

Two other Bush era air policies that sought to relax CAA regulation of acid rain pollutants and mercury have also been reversed as a result of litigation. The Clean Air Transport Rule (CATR), which is designed to reduce interstate emissions of NO_x by 52% and SO₂ by 71% below 2005 levels, has replaced a Bush era rule that was invalidated by the courts. As a result of the court decision, intrastate and only limited interstate trading of emissions allowances based on state pollution budgets is likely to be permitted when the EPA issues the final

CATR at the end of June. Coal-burning utilities in the Midwest and Southeast that are subject to the new CATR are, therefore, likely to be forced to decide whether to invest in expensive environmental controls, reduce operations, or retire the plants that cannot meet the new standards.

Coal generating units nationwide will be affected by the proposed rules on mercury emissions (also driven by judicial rulings barring market-based emissions trading for this hazardous pollutant). The EPA, pursuant to a settlement decree, issued regulations for mercury and other HAPs in March 2011; the final rule is due in November 2011. Utilities will be required to comply within three years. Given the court decisions against mercury emissions trading, utilities will face the choice of investing in a suite of environmental controls or moving away from coal.

Bernstein Research estimates that the cost of compliance with new environmental regulations for mercury alone could cause the retirement of 61 GW or over 20% of U.S. coal-fired generation capacity.

While some flexibility is allowed in controlling criteria pollutants, which require use of “reasonably available control technology” (RACT) or “best available control technology” (BACT), under the CAA, the EPA must determine the “*maximum* achievable control technology” (MACT) for hazardous air pollutants (HAP) and all sources of HAPs must install the MACT.¹⁸

According to Bernstein Research, the MACT for mercury reductions at coal-fired power plants may consist of an expensive combination of SO₂ scrubbers, a selective catalytic reduction system for NO_x control, and a fabric filter for particulate matter.¹⁹ The EPA, pursuant to a settlement decree, issued standards for mercury and other HAPs in March 2011; the final rule is due in November 2011. Utilities will be required to comply

within three years. Given the court decisions invalidating CAA cap-and-trade programs for NO_x and mercury, utilities will be restricted in their ability to buy pollution off-sets and will have to invest in this expensive suite of environmental controls if they are deemed to be the MACT. Bernstein Research estimates that the cost of compliance with new environmental regulations for mercury alone could cause the retirement of 61 GW or over 20% of U.S. coal-fired generation capacity.²⁰ Other estimates place the figure at 75 GW of coal-fired capacity that may be retired by 2030.²¹

Costs for these regulations are increasing and cumulative. The EPA’s 2006 amendments to the National Ambient Air Quality monitoring network required placement of new monitoring stations closer to the emissions source to measure local maximum concentrations of the six Clean Air Act criteria pollutants. It is expected that, after three years of data collection, few areas will be in compliance with even the more permissive limits for SO₂, perhaps triggering further reduction mandates. New rulings on primary levels of NO_x and SO₂ are expected to require compliance by 2017.²² Compliance deadlines for secondary levels have not yet been established, further augmenting financial risk due to environmental regulations. The Electric Power Research Institute (an industry sponsored organization) estimates that installation of one SO₂ scrubber on a 500 MW plant in the Midwest would cost about \$420/kW, or \$210 million.²³ While compliance with the SO₂ standard is costly, utilities may also have to install controls to meet new NO_x, ozone, and fine particulate standards as well.

The Electric Power Research Institute (an industry sponsored organization) estimates that installation of one SO₂ scrubber on a 500 MW plant in the Midwest would cost about \$420/kW, or \$210 million.

Unlike NO_x and mercury which have localized impacts, the impact of CO₂ and other greenhouse gases (GHGs) is global and, therefore, a cap-and-trade system may be permissible. However, the regulatory framework set forth in the EPA’s new permitting rules for GHG emissions, which took effect in January 2011, has not moved in that direction.²⁴

Since the EPA's authority to regulate GHGs was affirmed by the Supreme Court in 2007, the Agency has issued a series of rules to establish a GHG regulatory program, starting in 2009 with mandatory GHG reporting for facilities that emit 25,000 metric tons or more per year of CO₂-e (or carbon dioxide equivalent).²⁵ Although CO₂ emissions from coal-fired power plants dropped slightly to 34.6% of total U.S. emission in 2009 (due to the economic recession and displacements of coal by natural gas), most coal plants are major emitters and are required to report.²⁶ In April 2010, the EPA issued the Tailoring Rule, narrowing the GHG permitting program to the largest sources, those responsible for 70% of GHG pollution from stationary sources, including electric generating units.

The Final Rules, issued in late December 2010, require new or modified power plants (and other large stationary sources) that are already subject to the CAA to obtain permits from state regulators "that address GHG emissions." It is left to the state permitting authorities to determine the BACT for GHGs, although EPA has issued guidance on the process for determining the BACT. The Guidance notes that carbon capture and storage (CCS) is unlikely to be an available control technology:

The EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO₂ capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls.²⁷

While it remains to be seen whether Congress will allow the EPA's GHG regulatory program to go forward, it is clear that the industry does not benefit from continued regulatory uncertainty. According to one Department of Energy official, "[w]idespread cost-effective deployment of CCS will occur only when driven by a policy designed to reduce GHG emissions."²⁸ The cost of CCS can only be justified if there is a high enough price on CO₂ to warrant the massive investment to bring this technology to commercial scale and the increased cost of operating plants with CCS. Even then the question remains whether coal plants with CCS will be competitive with natural gas with CCS, wind, or other alternatives. The U.S. Government Accountability Office (GAO) has found that commercial deployment of carbon capture and storage technology for coal is 10 to 15 years away and "would increase electricity costs by about 30 to 80 percent."²⁹

Standard & Poor's stated in 2008 that it believes GHG compliance costs will be "the proverbial straw that leads to harsh regulatory responses such as a disallowance or deferral because of cost pressures tied to commodity prices, more capital spending for basic reliability needs on the transmission or distribution system, and added construction costs for new generation to meet rising demand [...] Clearly, the pursuit of a cooler planet will leave utilities sweating over the risk to their credit quality."³⁰

Water:

The Clean Water Act (CWA) prohibits the discharge of pollutants from a point source into navigable waters. Like key provisions of the CAA that languished in regulatory oblivion, CWA provisions applicable to coal-fired generators that were ignored for decades are now the focus of regulatory action.

Section 301(d) of the CWA requires the EPA to review the limitations for effluents from coal-fired power plants every five years, however, EPA had not set national standards to limit toxic metal discharges from the power plants since 1982.³¹ Following a lawsuit by environmental organizations, the EPA entered into a settlement in November 2010 requiring it to issue new rules on coal plant wastewater by July 2012 with final rules by January 2014.³² The EPA has identified 41 heavy metals in scrubber wastewater that will likely be subject to new regulation.

The U.S. Government Accountability Office (GAO) has found that commercial deployment of carbon capture and storage technology for coal is 10 to 15 years away and "would increase electricity costs by about 30 to 80 percent."

The CWA also directs the EPA to assure that cooling water intake structures (CWIS) reflect the best technology available for minimizing adverse environmental impacts. The Agency issued its CWIS rules for new steam electric generators in 2004. However, the rules for existing generators were suspended following a decision by the 2nd Circuit Court of Appeals in 2007. The EPA is in the process of developing new rules for both new and existing generators. Thermo-electric generators (whether powered by coal, gas, or nuclear fuel) use vast quantities of water for cooling and have major impacts on water resources. Cooling water intake destroys adult fish, fish larvae, and other aquatic creatures. When the water is released, it is considerably warmer than the temperature in the receiving water body, which may also harm aquatic life. New York and California have taken the lead in promulgating rules requiring installation of cooling towers that can cost over \$1 billion but “would cut the water intake by about 97 percent and eliminate the threat to the marine organisms.”³³

Concerns about cooling water are likely to become more acute as climate change causes both higher surface water temperatures, which would reduce the efficacy of the cooling water system, and water scarcity. During the drought in the southeastern U.S. in 2007, Southern Company and other regional electric utilities were forced to reduce operation at some of their plants due to water allocation that favored residential and agricultural use. In fact, water is now seen as a limiting factor on electric power generation.³⁴

Waste:

The Resource Conservation and Recovery Act (RCRA) controls hazardous wastes. However, coal combustion waste, which contains heavy metals and other toxic pollutants scrubbed from power plant smoke stacks, was not addressed by the EPA and regulation was left to the states. The catastrophic spill at the Tennessee Valley Authority (TVA) coal ash impoundment in December 2008 demonstrated that current regulations are not enough to prevent environmental and financial risk for utilities and their shareholders.³⁵

The EPA responded with proposed regulation of coal combustion waste, offering two possible options. The more restrictive rule would allow the EPA to regulate coal ash under Subtitle C of RCRA, which governs hazardous waste. The more permissive rule under Subtitle D would allow states to continue regulating coal combustion waste. Adopting Subtitle C will have upfront costs for the utilities but, according to EPA’s Regulatory Impact Analysis (RIA) of the proposed rules, the regulation of coal ash under Subtitle C would save an estimated \$5.3 to \$16.7 billion in avoided future coal combustion residues impoundment catastrophic failure cleanup costs, in addition to avoiding significant additional costs related to litigation, contamination of surface water, and human health risks.³⁶

Regulations Affecting Coal Mining

Water:

Section 404 of the CWA requires the Army Corps of Engineers to issue permits for discharges of dredged or fill material into waters of the United States. In June 2010, following years of litigation, the Army Corps of Engineers announced that it was suspending nationwide or general permits for mountaintop removal mining (MTR).³⁷ In July 2010, the EPA and the Army Corps of Engineers “clarified” their interpretation of the CWA, and essentially agreed with the anti-MTR plaintiffs that the impact of the valley fill on aquatic function as well as on stream structure must be assessed.³⁸ Since then, the EPA has revoked the permit for Arch Coal’s Spruce Mine, the largest MTR project in Appalachia, although other MTR projects have been allowed to proceed.

Mine Closure:

The Surface Mining Control and Reclamation Act (SMCRA) requires that coal mining companies set aside reserves to reclaim lands used for surface and deep mining and to meet high standards for reclamation. These standards have rarely been met by the mining industry. Of the roughly half-million acres of land covered by surface-mining permits in Kentucky over the last decade, less than 14,000 acres are scheduled to be reclaimed for commercial, residential, industrial, or recreational development according to state mining authorities.³⁹

Reclamation costs per ton of coal differ according to region, with eastern mines at the high end because of the depth of coal seams relative to the land and rock removed. In addition to paying a tax on coal to fund the cost of mine closures, mining companies must also post a bond and report their “asset retirement obligations” in their financial filings with the U.S. Securities and Exchange Commission (SEC). Requiring more timely reclamation or raising reclamation standards will add to the cost disadvantage of eastern coal.

Safety:

The Mine Improvement and New Emergency Response Act of 2006 (MINER Act) was designed to create new and expanded systems of accountability to improve employee safety. In the five months after the Massey Big Branch mine explosion in April 2010, the Mine Safety and Health Administration (MSHA) issued 1,287 closure orders, 285 more than during the previous 12 months. Senator Jay Rockefeller of West Virginia successfully pushed for an amendment of the finance reform bill mandating that mining companies disclose health and safety violations, enforcement actions, and the “dollar value of proposed assessments” by MSHA in their filings with the SEC.

The Rockefeller amendment had an almost immediate effect. For example, on 10 August 2010, Massey Energy filed an 8-K notice with the SEC, pursuant to the Dodd-Frank Financial Reform Act, reporting that it had received an “imminent danger order” at one of its mines. The company’s stock dropped 13% over the next four days.⁴⁰

II. COMMODITY RISK: COAL PRICE, PRODUCTION, AND DISTRIBUTION

The U.S. coal industry faces numerous changes that increase its risk profile. Coal prices are volatile, reflecting underlying tensions related to market shifts, costs of production, and regulatory changes. Production patterns are in transition altering longstanding business and price assumptions. All of these factors are moving coal in a direction that is not commensurate with the cost requirements of electric utilities, the primary U.S. market for coal. In order to retain profitability, the industry is shifting its supply to different parts of the U.S. utility market, moving high quality coal to steel markets, and seeking to export its product to more lucrative overseas markets. For the longer term, the industry is supporting new coal burning technologies with smaller environmental footprints.

Background

The U.S. has been referred to as the “Saudi Arabia of coal” with reserves estimated to last for at least 150 years. While such a claim might elicit a sense of stability and continuity, on closer examination the discerning investor will find that the Central Appalachian region—an area that once produced more than half of the nation’s coal, and still produces its highest quality coal—is literally off limits for new mine investment for a prominent banking institution and the largest coal mining company in the United States.⁴¹ The discerning investor would also find that recent studies by the United States Geological Survey (USGS) have significantly revised the “abundant reserve” estimates. The new estimates are based not only on how much coal is in the ground, but more importantly on the economic feasibility of accessing those reserves.⁴² The new estimates of economically recoverable coal are alarming and suggest coal supply, quality, and price problems evolving over the next 20 years.

Recent studies by the United States Geological Survey (USGS) have significantly revised the ‘abundant reserve’ estimates.

Each coal sub-region in the U.S. (Powder River Basin, Central Appalachia, Illinois Basin, Northern Appalachia, and Uinta Basin) has its own independent internal dynamics. The dynamics in two regions, the Powder River Basin (PRB) and Central Appalachia (CAPP) drive contemporary markets. CAPP mines are more mature and declining coal reserves together with increased regulations will produce price increases for the remaining high quality product. Geology, regulation, and markets are forcing a noisy end to the historically abundant, high quality coal produced in Central Appalachia. As CAPP coal becomes more expensive, it becomes less desirable as a fuel for electricity. Alternative strategies for CAPP producers in the utility markets hinge on coal blending strategies as well as new non-utility strategies aimed at steel and export markets. PRB, located in western U.S., is now the

nation’s leading coal producing region. The companies involved in its development are seeking to increase mining aggressively in the coming decades.

The trajectory of coal prices in each of these regions shows historically unprecedented levels of volatility with short and long term upward price pressures (see Table 3). These factors give coal a look quite different from its tradition of reliable, steady, slow price growth.

Energy expert Daniel Yergin writes that estimates of the U.S. natural gas resource base, including shale gas, “are now as high as 2.5 trillion cubic feet,” which amounts to “more than a 100-year supply” of natural gas for all uses from home heating and cooking to petrochemical and electric power production.⁴³

The rapid drop in natural gas prices from mid-\$8 per mmBtu to \$4 per mmBtu that occurred during 2008 has stabilized. Analysts are predicting long term, modest increases. For example, The Brattle Group’s analysis shows natural gas prices rising by 1% or less annually through 2035. In the near term the Brattle analysis projects average prices through 2020 under \$6.50 mmBtu.⁴⁴ A recent report by Bernstein Research measures the current impact:

On a national basis the increased competitiveness of gas-fired plants has led to a marked shift in the composition of power supplies. In 2009, the output of the nation’s coal fired fleet fell by 12%, while gas-fired generation increased by 4%. This shift in favor of gas failed to reverse in 2010, when coal and gas-fired generation rose by roughly equal amounts (5% and 6% respectively). As stark as they are, national and regional aggregate data mask the extent to which the changing relative prices of gas and coal have eroded profitability of individual coal-fired power plants.⁴⁵

Given future predictions for relatively flat gas prices, low power prices, and volatility in the price of coal, underutilized gas plants will be called upon to dispatch before coal-fired plants on an increasing basis. The impact on the bottom line for coal-fired generation strikes deep. “Gross margins in competitive power markets fundamentally boil down to fossil fuel arbitrage. In any given hour the marginal generating unit sets the energy price for all producers. Spot and forward power prices track the commodity prices of the price setting fuel,” which in most markets is natural gas.⁴⁶

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– *Deutsche Bank*

Industry analysts M.J. Bradley & Associates and the Analysis Group found that “existing gas units have significant untapped power production potential, which can be expanded during off peak periods without constructing new generation.”⁴⁷ Utilizing this untapped capacity, converting existing coal plants to gas, and constructing new natural gas plants are all currently least cost options that energy decision makers must consider in evaluating whether to invest in or retire coal plants.

Peabody Energy projects an increase in coal prices upwards of 105%-155% over the next five years.

The Price of Coal

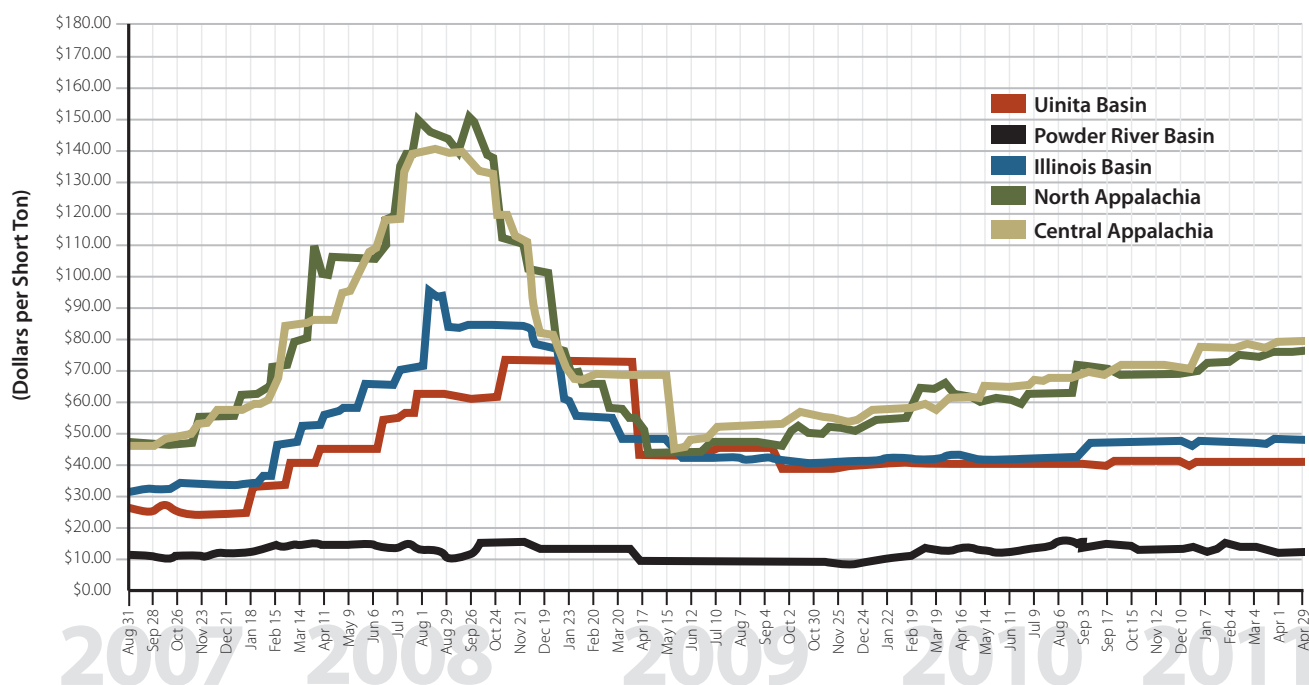
Utilities have historically relied on inexpensive coal as a low-cost generating fuel to meet base-load demand for electricity. Utility industry models typically assume the price of coal will rise at a slow and steady rate. The U.S. Energy Information Administration’s long-term coal outlook, for example, assumes the future price of coal will rise 1.7% annually through 2030.⁴⁸ Yet coal industry analysts and the coal producers

themselves disagree with this projection. Instead, they find that, “due to the global and domestic supply, demand and volatility drivers, we believe that price volatility will continue to increase. In other words, regardless in which direction they may ultimately trend, the price swings will be more erratic and of greater magnitude.”⁴⁹ Mining companies also differ from utilities in their projections for the price of coal. For example, Peabody Energy projects an increase in coal prices upwards of 105%-155% over the next five years.⁵⁰

Exported coal in both the thermal and metallurgical markets command higher prices than when it is sold domestically. For example, Peabody stated that it could sell PRB coal on the China/Asian market for \$26.02 per ton, whereas the same coal in U.S. markets would sell for \$13.65.⁵¹ The disruption to Australian coal exports due to the recent massive flooding in that country is expected to increase prices for U.S. Eastern coal to historic highs: driving metallurgic coal up 13% from last year to \$254 per ton, and thermal coal for power plants up 20% to \$74 per ton.⁵² The Japanese tsunami and subsequent nuclear meltdown at the Fukushima power plant have increased Japan's demand for coal (it is already the largest importer of thermal coal) and pressure on international coal prices.⁵³ Exported Central Appalachian coal, which can be sold at a higher price, offers a clear way to offset rising costs of production and dwindling supply of high quality coal.⁵⁴ The higher price yields a higher profit per ton and enables the companies mining CAPP coal to retain some semblance of profitability.

The following chart plots the spot-price of coal from 2007-2011. After the sharp decline in 2008, regional coal prices rose rapidly in 2009 and into the spring of 2011. The chart shows increased volatility and the current trend of price increases.

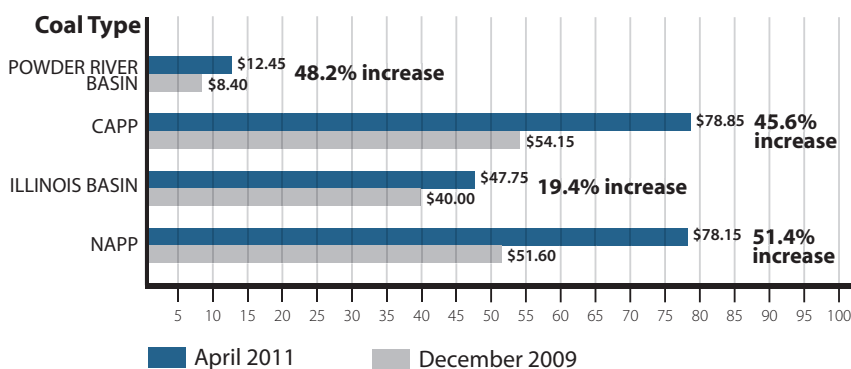
Table 2: Historical Average Weekly Coal Commodity Spot Prices ⁵⁵



After the sharp decline in 2008, regional coal prices rose rapidly in 2009 and 2010. In contrast to decades of stable pricing seen in the 20th century,⁵⁶ the NYMEX futures projects increases for each region's coal prices in 2011 of between 4% and 8%.⁵⁷ These 2011 price increases are high by historical standards, but low compared to increases experienced in the last few years. A recent analysis by the Texas Independent Supply Operator, Electric Reliability Council of Texas (ERCOT), projects 20-year delivered PRB prices for Texas in the range of \$75-\$100 per ton, amounting to an annual price increase from 8-12%.⁵⁸ Several companies – Peabody in the Powder River Basin and Illinois Basin and Massey Energy, Patriot, and CONSOL in Central Appalachia – are looking to more robust pricing. CAPP producers are hoping to capture more revenue by shifting production and marketing of high quality coal toward the steel industry. The higher prices will offset declining production, keeping some semblance of a price floor under CAPP coal as it loses demand from the utility sector.⁵⁹

In Central Appalachia, the region's declining coal reserves, which are more difficult to access, and intensified regulatory oversight require rising prices to cover the increased production costs and the growing scarcity of the high value coal. In the current climate where CAPP coal is seeing some loss of electric generation demand and a moderately robust export market, prices tend to be flat or rise slowly, squeezing CAPP coal producers' margins against rapidly rising costs of production.

Table 3: Spot Price of Coal December 2009-April 2011⁶⁰



The shift from CAPP to PRB (and, to a lesser degree, Illinois Basin) as the leading coal producing region means that mining activity will intensify in the Powder River Basin. The PRB is already being intensively mined and marketed and is projected to produce at levels beyond the U.S. Energy Information Administration's (EIA) projections. The demand for PRB coal will continue to push prices up and increase costs of production. This is beginning to be seen in price increases for PRB coal, up 59% from 2009 to 2010, and the doubling of operating costs in the region since 2003.⁶¹

Cost of Coal Production

The cost of production of mining coal is rising in each region of the country, more rapidly in some places than in others.⁶² The upward pressure on price threatens coal's future as a fuel source for electricity generation in some regions and is forcing important business changes and creating new risks in others.⁶³

Central Appalachian Coal:

The cost of producing coal in this region is rising due to "discrete geologic conditions, increased regulatory enforcement actions and related temporary shutdowns, increased labor turnover rates, unplanned crew transfers, [and] higher surface mine ratios."⁶⁴ For example, Massey Energy, one of the largest producers of CAPP coal, reported that its average cost per ton of coal rose from \$34.00 to \$50.48 from 2005 to 2009 — an increase of 48%.⁶⁵ In its most recent filing of 2010 results, the company reported its cost per ton of coal at \$60.05, a 58% increase from 2005.⁶⁶

As costs of production rise, companies in CAPP are keeping costs down by using surface mining, or MTR mining. Yet, due to regulatory and reputational risks associated with MTR, companies are now questioning if the less expensive MTR coal is worthwhile. In June 2010, Duke Energy put out a request for proposals (RFP) for coal that distinguished between coal mined underground and coal obtained from MTR. It costs between \$10 - \$20 per ton more to produce coal from an underground mine than via MTR. Duke's RFP exposed the fault line, revealing that the cost of production from underground mining in a mature region would produce coal at a price too high for domestic markets for electric power generation.⁶⁷

In the last six months Duke Energy, AEP, and Southern Company have each made explicit or implicit comments regarding their retreat from the use of Appalachian coal.⁶⁸

Powder River Basin Coal:

In the PRB, now the largest coal producing region in the nation, companies plan to intensively mine existing reserves. The U.S. Geological Survey has published several studies showing that as the region's mines mature there will be an increased cost of production. It will stem from the need to: 1) use more fuel, labor, and machines to dig deeper to get coal that has been heretofore closer to the surface; 2) to build road, rail, and other infrastructure to access new mines; and 3) to address planning considerations related to local land use, environmental impacts, and wildlife, water, and political jurisdictional issues in western communities.⁶⁹ Anecdotally, production-cost increases are already being reported in the region; however, they are mitigated by a rising price environment.

Distribution Risks

Most coal produced in the U.S. moves by rail and rail transportation costs can range anywhere from 10% to almost 70% of the delivered price of coal, depending on the type of coal purchased and location of the power plant. Given that most of the nation's rail companies transport more than just coal, the coal industry faces price and coordination issues related to the larger economy. Coal deliveries run a gamut of economic, physical, weather related, and price risks whether they are within the west, from west to east, east to west, within the east or any combination of rail to barge or ship to rail. Those risks, which can disrupt supplies, harm production at mines, and hurt coal producer profitability on the one side and/or harm utilities on the consumer side of the equation.

Rail congestion and weather related issues on the Norfolk Southern line that runs east of the Mississippi recently created problems for Patriot and Massey Energy, two coal companies that cited transportation problems as part of the explanation for poor performance.⁷⁰ Similarly, FirstEnergy cited rising transportation costs of their coal supply as a factor in their 24% earnings decline from last year.⁷¹

Factors to Watch

Coal producers face a shifting array of factors that impact the price, quality, and ultimate use of their product by the power generation market. Natural gas, solar, wind, and energy efficiency are serious competitors at a time when new investment decisions must be made. A growing international marketing outlook is emerging in response, as production costs increase and coal producers most affected look to greater levels of sales to the steel industry. The potential for new laws on emissions of carbon dioxide are stimulating research and development into carbon capture and sequestration and diminished coal quality is promoting a host of alternative strategies.

International Markets:

Coal is exported from the U.S. to destinations in over 40 countries. Exports ranged from 48 to 81.5 million tons per year between 2004 and 2009. On average, between 15-18% of coal exports are shipped to Canada via rail. Most of the industry is now looking to a larger percentage of production going to exports as part of their future.

From 2007 to 2009, it became clear that international export sales could improve the short-term revenue picture for coal companies and place upward pressure on prices domestically, at the same time that coal was losing its dominance in the U.S. electric-power sector.⁷² A coal industry market analysis confirmed that U.S. domestic markets were functioning in a new manner: 1) exporting coal was increasingly profitable, leaving less supply for domestic needs; 2) international prices and domestic geology would drive long term rising price volatility; and 3) inadequate utility and regulatory mechanisms were in place to handle price volatility.⁷³

The drive to export is not without contradictions for coal companies, utilities, and investors. On the one hand exports can prop up sagging revenues with sales to more lucrative markets. Some utilities may benefit, in the very short term, from rising coal prices. On the other hand, rising coal prices in a domestic energy market where natural gas prices remain relatively flat and wind, solar, and other alternatives are improving will further diminish coal's market share.

The drive to export is not without contradictions for coal companies, utilities, and investors. Rising coal prices in a domestic energy market where natural gas prices remain relatively flat and wind, solar, and other alternatives are improving will further diminish coal's market share.

Export of PRB coal is currently hampered by lack of capacity at the nation's seaports. In 2008, the U.S. exported 81.5 million short tons of coal, approximately 7% of total production. The maximum capacity of all U.S. terminals capable of handling seaborne coal is 130 million tons.⁷⁴ As such, export of the majority of U.S. coal production would require significant innovation and investment into both the rail and port systems.

The coal industry has been pushing for several years to improve port capacity within the U.S. and Canada, particularly in the west. These efforts face many challenges such as were seen in 2003 when the City of Los Angeles canceled contracts for plans to expand its terminal capacity. Recently the industry has gotten behind a new terminal project in Cowlitz County, Washington. After an intensive public hearing process the developer temporarily withdrew its application for the permit.⁷⁵ Peabody Energy, however, has recently announced another port project for the State of Washington.⁷⁶ Similarly, U.S. coal producers have increased efforts to expand access to ports off of Canada's west coast.

The relative increase in exports is currently projected, at best, to be another 100 million tons after considerable investment in rail and terminal capacity. This will not offset what is likely to be a considerably larger loss in demand for coal should U.S. electricity consumption switch from its generation mix from 46% coal to 30% or 20%.⁷⁷ Under such a scenario a much smaller coal mining industry would be envisioned.

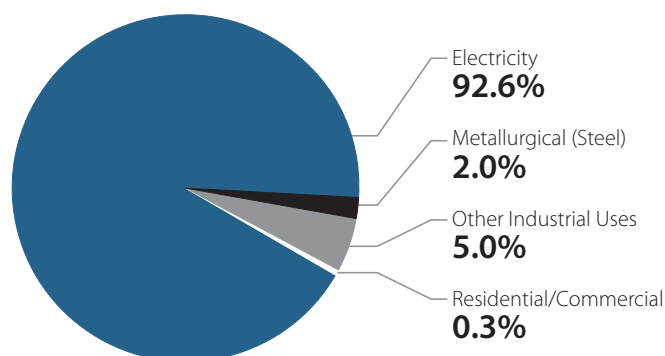
Non-Utility Domestic Markets:

Non-utility uses of coal accounted for 8% of total domestic coal consumption in 2008, as seen below.

The largest single industry purchasing coal, after electric utilities, is steel. In 2008, the demand for coal from the U.S. steel industry was 22.7 million tons. This is 2.5% – 3.5% of domestic coal supply, compared to the almost 90% currently purchased by utilities. A group of industries—cement, glass, ceramics, and paper—collectively purchase 5% of U.S. coal production.⁷⁹

The coal industry supports various coal-to-liquid projects as a way to develop prospective markets. However, none of these can make up a significant loss in demand from the electric generation business.⁸⁰ While metallurgical coal production and sales will not affect large percentages of the nation's supply, significant tonnage is being targeted by individual companies to the steel industry. This has important implications for the revenue picture and share value for those mining companies.

Table 4: 2008 End Use of Coal Mined in the U.S. (1123.8 MM tons)⁷⁸



Coal Quality:

When an electrical generation plant switches coal types during the course of its useful life, a series of risks arise related to the new coal type, mixing standards, new procurements, and price risk. As energy planning takes place now, and hundreds of decisions across the country must be made about plant upgrades at more or less the same time, not only the price, but also the quality of coal becomes important. The 2008 U.S. Geological Survey (USGS) report suggests that the quality of U.S. coal will decline within 10 years. The USGS report expresses concern with the long-term quality of PRB coal coming from the Gillette coalfield particularly because the British thermal unit (Btu) value of coal from many of the beds that will be mined in the future is not consistent. The USGS concludes that “quality parameters such as increased ash or lower heat Btu content negatively impact the operating and maintenance costs at coal-fired power plants.”⁸¹

New Technologies:

For both the coal mining and the utility industries, research and development is underway on a global scale to make available commercially viable technologies that can mitigate CO₂ emissions. The most promising technology is carbon capture and sequestration (CCS). The process captures CO₂ and stores it underground rather than emitting it into the atmosphere. As previously noted, a recent GAO analysis, found that CCS technology within the United States is 10-15 years away from the kind of maturation where commercial deployment on a wide scale is feasible and it would likely increase the cost of coal-fired electricity by 30% – 80% above current levels.⁸²

As a solution to the risks facing the use of coal by utilities, CCS offers a question mark to the future balance sheet. In its current state, CCS technology is a speculative outlay by a utility as there are no clear assumptions upon which a return on investment can be reliably determined.⁸³ A recent Bernstein Research manuscript suggests that even if CCS proves successful, the ongoing risky nature of coal, given the other air and water quality problems it faces, still present significant risks going forward.⁸⁴

The industry has also supported various coal-to-liquid projects as another means of propping up demand for coal. Those projects, like CCS, require long-term governmental support to develop robust markets.⁸⁵

III. CONSTRUCTION RISK

Background

Traditionally, coal mining companies, electric utilities, public utility commissions, public service commissions, and capital markets have supported the expansion of coal-burning facilities as the least expensive, most reliable generation source for electricity. At present, this formerly unified “coal finance complex” is splintering.⁸⁶ One of the primary reasons utilities are not getting support for either new construction or retrofits to existing coal plants is the increased cost of construction and the burden of financing these capital expenditures (CapEx). The risks differ for new construction and upgrades to existing plants, but in both cases recent trends indicate a disinvestment in coal-based CapEx, putting pressure on utilities to develop new business models that are not based on coal and, as addressed in the previous section, on mining companies to find new markets for their product.

The electric utility industry and its component companies are at a crossroads. They can adopt strategies that replace some coal plants and achieve some near term pollution reduction while facing continued regulatory uncertainty and hope for potential technological changes to promote a resurgence, or they can invest in efficiency and cleaner energy alternatives.

New Construction Risks

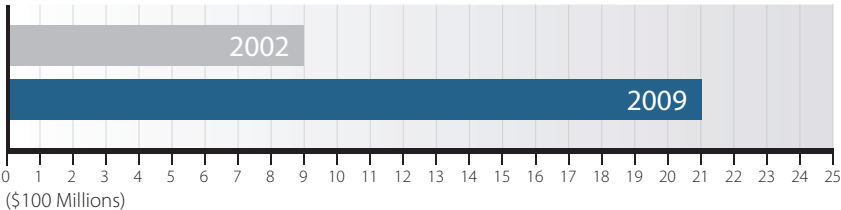
In 2007 utilities announced plans to move forward with 151 new coal plants across the U.S.⁸⁷ This new plan to supply power to service regions around the country was supported by industry experts who provided guidance to the network of investor-owned utilities, state-run public authorities, rural electric cooperatives, and municipal electric systems that run the nation’s largely decentralized energy policy. Other energy stakeholders had plans for new coal generation facilities in addition to these industry/government-sponsored initiatives. But the public utility commissions have rejected, or the companies have themselves, cancelled or postponed 153 plants.⁸⁸ The plant cancellations amounted to \$243 billion in investment decisions being reversed, or disinvested, from coal in four years.⁸⁹ Mirroring this trend, in February 2008, the U. S. Department of Agriculture’s Rural Utilities Service (RUS) declared a moratorium on any new coal plant financing.⁹⁰ Although RUS had been financing rural electrification projects, many in heavily coal dependent states, for over 70 years, the agency’s limited public statements made it clear that it would no longer finance new coal plants because the market was volatile and investments were considered too speculative.⁹¹

Public utility commissions have rejected, or the companies have themselves, cancelled or postponed 153 plants. The plant cancellations amounted to \$243 billion in investment decisions being reversed, or disinvested, from coal in four years.

In addition to the regulatory uncertainty and the upward price pressure and volatility for coal discussed above, two other major factors are driving the decisions to cancel the coal plants:

- **Increasing construction costs:** Costs for raw materials as well as for professionals and skilled labor increased exponentially. For example, in 2002 a 600 MW plant cost \$1500 per KW to build (\$900 million), by 2009 that same plant design cost \$3500 per KW or \$2.1 billion. The rapid increases were primarily attributed to rising demand by China and other countries for raw materials and engineering labor.

Table 5: Increasing Construction Costs



- **Poor load forecasting:** As changes in demand and the economy evolved, some utilities acknowledged weaknesses in the forecast models used by the industry to project future electricity use.⁹² When overstated load forecasts were identified, the new plant was no longer viable.

Ultimately, industry decision-makers (including utility commissions and company executives) determined that the new plants would add unreasonable and unnecessary costs and ongoing risks to the price of electricity for consumers and businesses. Some plant proponents have continued with project development despite warnings. Recently the Prairie State Energy Center in Illinois announced that, due to construction cost overruns, the cost of electricity from the new plant—still under construction—had grown by over 30%.⁹³ Duke Energy is faced with considerable opposition to its Edwardsport, Indiana, project due to rising costs in excess of 30% and an ethics scandal.⁹⁴

Overstated load forecasting was also a factor in new plant cancellations.⁹⁵ In these cases, projections of future growth that would support the need for large plants and the large capital investments for new coal technology were considered inaccurate and forecasts that showed smaller or flat growth suggested to policy makers there was less of an immediate need for action or that actions short of new, large coal plants including smaller plants, energy efficiency, and renewables could be taken.⁹⁶

As changes in demand and the economy evolved, some utilities acknowledged weaknesses in the forecast models used by the industry to project future electricity use. Michael Morris, the chief executive of AEP, stated that he thinks the industry should be wary about breaking ground on expensive new projects. "The message is: be cautious about what you build because you may not have the demand" to justify the expense.⁹⁷

Retreating from a new plant already underway also has significant economic impacts. AMP Ohio announced in December 2009 that it was canceling plans for its Meigs County project due to a 37% cost increase. Upon cancellation, the 81 local governments that were partners in the project were informed that they owe, collectively, \$200 million. The full amount of the liability and actual allocation schedule for the 81 communities is in litigation.⁹⁸

Since the dramatic spikes of 2002-2009, construction prices in the United States have leveled off. However, they have evened out at historically high levels.⁹⁹ The overall price increases in the U.S. did not respond appreciably to the 2009 recession as both the AMP Ohio and Prairie State examples illustrate.

Upgrading Existing Facilities

The U.S. fleet of coal-burning facilities is aging and requires significant expenditures to comply with current and future regulations. Older plants will require additional investment regardless of the EPA seeking compliance with air quality regulation. Many plants currently do not cover costs, even with capacity revenues.¹⁰⁰ Industry analysts concur that it is economically challenging to justify investment in pollution control equipment for smaller coal plants.¹⁰¹ One analyst estimates that 24% of the nation's coal fleet may face retirement because it is old, small, inefficient, and requires investment in pollution control equipment that cannot be justified.¹⁰²

The table at right indicates the age, size, and emissions equipment status of the US coal fleet.

Table 6: Status of U.S. Coal Plants ¹⁰³

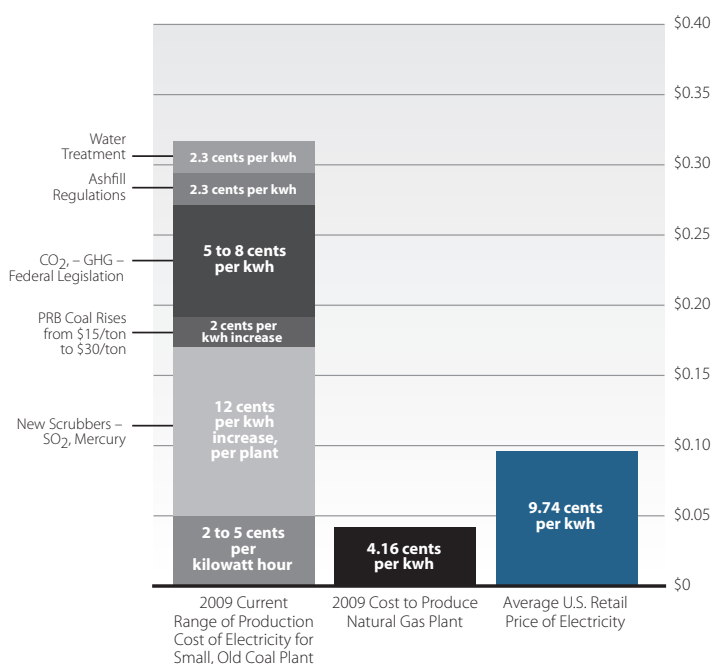
UNIT AGE	UNIT COUNT	% of ALL UNITS	CAPACITY (MW)	% of US CAPACITY	AVG. UNIT SIZE (MW)	LACK CONTROLS
> 60 years	46	5%	1,762	1%	38	87%
51-60 years	313	31%	39,787	13%	127	64%
41-50 years	233	23%	58,078	20%	249	53%
31-40 years	229	23%	114,090	38%	498	27%
11-30 years	163	16%	80,165	27%	492	31%
<11 years	7	1%	2,444	1%	349	29%
TOTAL	1,004		297,639			48%

The costs to larger plants are significant and, while spread across more generating capacity, are not necessarily financially sound expenditures. The head of analysis for Bernstein Research estimates that “a sulfur dioxide scrubber costs 36 cents a watt, or \$360, for a 1 gigawatt plant, but \$1.14 a watt for a 50 megawatt plant. For \$1.14 a watt you can buy a spanking new gas-fired plant.”¹⁰⁴ The small retrofit project is cost prohibitive.

The drop in price for natural gas has made the cost of retrofitting a plant even more problematic on two fronts. First, on a day-to-day basis, natural gas plants now compete successfully with coal plants in many regions of the country. Enforcement of EPA regulations only increases natural gas’s advantage as an inexpensive source of electricity generation, as seen in the chart at right.

Second, while the issue of today’s coal and natural gas prices focuses on short term market share – quarterly revenue targets, dividends, and stock prices – the issue of retrofits is about capital investment, a decision that affects the next 30 years or more. Justifying investment in additional CapEx for plants or categories of plants that are not meeting revenue targets and may be the cause of loss of company value will become increasingly difficult for executives or regulators.¹⁰⁶

TABLE 7: Competitive Disadvantage of Existing Coal-Fired Power Plants¹⁰⁵



Justifying investment in additional CapEx for plants or categories of plants that are not meeting revenue targets and may be the cause of loss of company value will become increasingly difficult for executives or regulators.

IV. A CONSENSUS AMONG INDUSTRY ANALYSTS

Coal Fleets Are at Risk

Over the past year an industry consensus has developed that goes beyond the discussion of retirements of small, old, unscrubbed, inefficient plants. A series of studies has shown that coal plants, once solid, stable, affordable parts of the nation's electricity grid, are now uncertain, risky, volatile, costly investments requiring extra diligence.¹⁰⁷ The studies have followed a progressively pessimistic course: first finding that smaller, old, inefficient plants with no pollution control technologies should be replaced; second, concluding that larger ones similarly situated should face the same fate.¹⁰⁸ Then, as the full recognition of the long-term impact of low natural gas and power prices took hold, it became apparent that the nation's merchant fleet of coal plants was also precarious.

Bernstein Research, which issued several of these studies, concluded in its February 2011 analysis that given low natural gas prices for the foreseeable future:

The compressed gross margins of the nation's least efficient coal-fired power plants, and especially those unregulated units burning Appalachian coal, renders these units highly vulnerable to cost increases. In particular, environmental regulations requiring costly retrofits to limits emissions of air pollutants, or to upgrade cooling water intake structures, could prove uneconomic for many plants.¹⁰⁹

What the prolonged impact of low natural gas and power prices, regulatory uncertainty, and changes in coal markets will mean for the regulated utilities is only beginning to become apparent. The choices however for utility regulators seem clear in light of the cumulative risks of coal.¹¹⁰ How can higher priced coal-fired generation be justified to ratepayers when there are demonstrably cheaper alternatives?

M.J. Bradley & Associates:

The Bradley analysis identifies the largest cohort of unscrubbed plants in the country that are old and below 250 MW capacity.¹¹¹ The report lists 40 plant closing announcements (of which seven plants were above 250 MW and two were less than 40 years old) to demonstrate that utilities have concluded this type of plant is not worth investing in.¹¹² The Bradley study points out that almost half of the nation's coal plants are scrubbed, that additional new capacity is being planned (coal, natural gas, and nuclear), and that sufficient reserve margins exist and policy and procedures are in place to protect grid reliability.¹¹³ In short, further retirements of unscrubbed coal plants are both likely and desirable.

Prominent in the study is the finding that natural gas plants throughout the country are underutilized. The study demonstrates that natural gas plants' utilization rates are considerably below that of coal plants. Given the low price of natural gas, it is clear that in many regions the loss of a coal plant should provide more immediate benefits to local consumers than costs. The study raises the potential that existing coal plants might be good candidates for new repowering projects – converting the plants from coal to natural gas.¹¹⁴

Bradley's broader policy perspective views energy regulation as a series of choices and incentives to investors for upgrading and modernizing the nation's energy supply. In addition to efficiency benefits derived from new investment, the regulatory process also reduces air pollution hot spots across the nation by retiring coal plants that are major contributors. The elimination of these hot spots is seen as a step to removing broader impairments to local economic development efforts.¹¹⁵

The Brattle Group:

In December 2010, The Brattle Group released a study of coal plant retirements. While a host of other analyses have been released from investment houses and policy think tanks, the Brattle study offers a leap forward in both method and substantive conclusions. The principal finding is that one-third of the economic retirements (50-66 GW) identified by its research are plants younger than 40 years old and larger than 500 MW units. The Brattle analysis underscores “the importance of considering regional market conditions in addition to unit age and size.”¹¹⁶

The study adopts two standards, one for regulated utilities and one for merchant plants. For regulated utilities, if future coal plant operating costs plus environmental CapEx are more than the cost of replacement power for a natural gas combined cycle plant plus a 20% stranded cost assessment, then the plant should be retired.¹¹⁷ This particular model focuses more on comparative costs, that is, what choice does a regulator have if not coal. The model uses as a comparative benchmark a new combined cycle gas plant (not unlike the early Bernstein analysis). The Brattle Group analysis employs a 20% stranded asset provision as an acknowledgement that the broad economic reality facing utilities and regulators requires settlement of the value of the existing useful life on currently operating coal plants. Regulators could either combine such costs into one rate case or separate out the cases as plans for new natural gas or other power generation went forward. Low natural gas prices, low interest rates, and a faltering coal plant market suggest current economic conditions have provided a window of opportunity for retirements.¹¹⁸

For merchant plants, if power prices are insufficient to cover the cost of operation and debt, then the plant should be retired.¹¹⁹ The model captures the fundamental diseconomies of coal for merchant generators in the current environment. That is, they are producing electricity under market conditions where low natural gas prices are producing low power prices. Electricity sales, therefore, are not producing sufficient revenue to pay for the cost of plant operations plus new CapEx. With future power prices appearing flat and more investment in coal plants required to achieve regulatory compliance in the future, the prospects for profitable merchant generation are not promising.

For merchant plants, if power prices are insufficient to cover the cost of operation and debt, then the plant should be retired.

The Brattle Group’s conclusion that all 13,000 MW of merchant coal generation in Texas should be retired provides an extraordinary example of the financial problems facing coal plants. While not shown in this report, the local regional economics that have undermined the viability of coal generation stem from low natural gas prices and competition from wind generation.¹²⁰ The fact that Texas utilities burn

a combination of PRB and lignite coal and still are uncompetitive provides an additional dimension to the debate over retirement.¹²¹

The Brattle report, like many of its counterparts, then projects out how much coal-fired generation could be retired as a result of the combined impact of local market forces and various regulatory scenarios and timetables. They estimate between 50 and 66 GW’s will likely be retired if the EPA imposes a scrubber mandate (and an estimated 110 million fewer tons of coal burned). The paper provides clear economic standards that demonstrate where merchant plants and younger, large plants can be retired.¹²²

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The analyses in these reports crystallize the risks facing any utility with a coal fleet however large or small. Invariably, as retirement/replacement strategies are pursued by various companies and public power regulators, other considerations will emerge but there is now consensus regarding the following criteria for plant retirements:

- Costs cannot be covered by known revenue potential.
- Alternatives such as natural gas plants are cheaper and less risky.
- Prices and competition from alternatives in local/regional power markets have undermined financial stability of coal plants.
- Utilities that are similarly situated have chosen to retire similar plants.
- Legislatures have created the legal and regulatory climate favorable to retirement of existing plants, including processes to absorb the value of existing plants in future rates.

Viable Alternatives to Coal

A large-scale shift away from coal is possible and would be economically and environmentally beneficial. Energy efficiency, existing natural gas capacity, and cost competitive renewable energy provide a glide path for this transition. M.J. Bradley & Associates’ analysis of system reliability concludes that “even though some [coal-fired] units likely will retire in lieu of complying with the new [EPA] regulations, electric system reliability will not be compromised if the industry and its regulators proactively manage the transition to a cleaner, more efficient generation fleet.”¹²³

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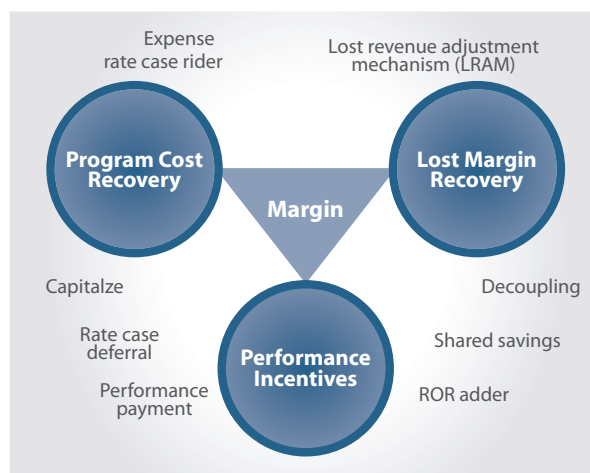
Energy Efficiency:

The cheapest source of new energy is to use the electricity already being produced more efficiently. Efficiency is a key component to reducing demand growth, which, in turn, will cut carbon emissions as consumption of coal and other fuels for electricity generation decline. Furthermore, “energy efficiency portfolios typically save electricity at a cost of about 3 cents per kwh, which is roughly two to three times less expensive than many supply-side resources.”¹²⁴

Energy efficiency and demand response programs saved almost 105,000 GWh of electricity in 2008, and by 2018 energy efficiency is projected to reduce summer peak demand by 20,000 MWh.¹²⁵ The Electric Power Research Institute estimates that energy efficiency programs, along with demand response systems, lower the growth rate for electricity consumption by 22% and the growth rate for peak demand by 46% compared to EIA projections.¹²⁶

Reducing energy use, however, conflicts with the ways utilities have traditionally earned revenue, by selling more kilowatts to consumers. The Minnesota Public Utilities Commission found that a “one percent decline in sales can reduce earnings by about 10 percent for distribution-only utilities and 7 percent for vertically-integrated utilities.”¹²⁷

Table 8: Revenue Models for Utilities ¹²⁸



Revenue decoupling is one mechanism that protects utilities' revenues by guaranteeing a utility's rate of return to cover its fixed costs regardless of sales volume and provides a base from which utilities can support efficiency programs for their customers.

Natural Gas:

Natural gas has a lighter environmental footprint than coal with 60% less CO₂/MWh, 80% less SO₂, and no mercury or particulate emissions.¹²⁹ Generation from natural gas requires less water and waste handling than generation from coal, it is now price-competitive with coal, there is existing capacity in the U.S., and it is relatively inexpensive to build new natural gas plants. Deutsche Bank Climate Change Advisors concluded, based on a comprehensive study of U.S. natural gas resources by researchers at the Massachusetts Institute of Technology, that there will be an adequate supply of gas and at sufficiently low prices to accommodate a switch of 60 GW of coal to gas by 2020 and an additional 92 GW by 2050.¹³⁰

Natural gas may offer the best option as a transitional fuel as the U.S. energy infrastructure integrates more renewable resources into the power grid and shifts away from coal. Gas plants, often built to provide energy during peak demand, are more nimble than base-load coal plants. Gas plants can be called upon to smooth out the variability in power supplied by intermittent sources like wind and solar.

Deutsche Bank Climate Change Advisors determined that utilities following a least-cost planning framework were most likely to reduce coal output and increase output from existing gas assets and/or replace their retired coal capacity with natural gas.¹³¹ Current natural gas plants are utilized, on average, 20% of capacity and 40% in peak summer.¹³² Natural gas assets make up 42% of the U.S. power sector capacity, enabling significant electric output if plants are operated closer to capacity.¹³³

According to Deutsche Bank, there is not only sufficient capacity, but also sufficient existing and planned pipeline to transport natural gas to regions where coal plants will most likely be retired. The gas infrastructure will require "modest expansion to the already mature U.S. natural gas pipeline system" and "incremental natural gas pipeline capacity additions of about 10-12% of the total current pipeline network."¹³⁴ Deutsche Bank notes that much of the 40,000 miles of pipeline currently planned or under construction is located in areas with "at risk" old coal-fired power assets.¹³⁵

Although natural gas has a lower environmental impact than coal, "unconventional" shale gas extraction poses serious environmental risks that need be addressed. Hydraulic fracturing, a process that injects high volumes of water, chemicals and particles underground to create fractures in the shale through which gas can flow for collection, is used in 90% of operational wells today and 60-80% of new wells will require fracturing to remain viable.¹³⁶ There are significant concerns associated with the lifecycle impacts of fracturing operations: the toxicity of the chemicals; the disposal of waste water; and the release of methane, a potent greenhouse gas. Before natural gas can be fully embraced as a bridge fuel, steps must be taken to manage and mitigate these associated risks.

Companies conducting fracturing operations must manage millions of gallons of wastewater, which include portions of fracturing fluids that return to the surface plus naturally-occurring formation waters brought to the surface during and following fracturing. This water contains the chemicals used in the fracturing process, dissolved solids, heavy metals, and in some cases, naturally occurring radioactive materials.¹³⁷ The wastewater must be stored, transported, treated, and disposed of, and/or recycled. Recently, natural gas companies have begun using less-toxic formulations for fracking fluids and, under pressure from regulators, communities and investors, are moving toward increased disclosure of the chemicals used.¹³⁸

Deutsche Bank Climate Advisors concluded that there will be an adequate supply of gas and at sufficiently low prices to accommodate a switch of 60 GW of coal to gas by 2020 and an additional 92 GW by 2050.

Natural gas has significant advantages over coal in lowering CO₂ emissions for the electric power sector. When burned, natural gas releases 60% less CO₂ than coal. Analysts such as Deutsche Bank Climate Change Advisors believe that it will be more economical to apply CCS to natural gas plants than coal plants, estimating that retrofits to natural gas plants will be 10-15% less expensive.¹³⁹ However, the principal component of natural gas, methane, has a global warming potential 25 times higher than CO₂. A recent study by Cornell University found that “3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well.”¹⁴⁰ Methane and other emissions can occur throughout the natural gas supply chain. In hydraulic fracturing, it escapes from flow-back return fluids and drill out following the fracturing. These gas production emissions risks must be addressed if natural gas from shale is to provide a solution for lowering the GHG footprint of the electricity industry in the U.S.¹⁴¹

Renewables have seen significant growth at a time when other energy sectors have declined. In 2008-2009 electricity generation from renewable resources expanded by 8% in the U.S. while the total net generation declined by 4%.

Controversies over the environmental impact and safety record of the shale gas extraction industry are bringing demands for greater oversight and regulation of hydraulic fracturing at the state and federal levels. Opinions vary as to the impact that new regulations would have on the cost to produce electricity from natural gas and research is currently underway.¹⁴²

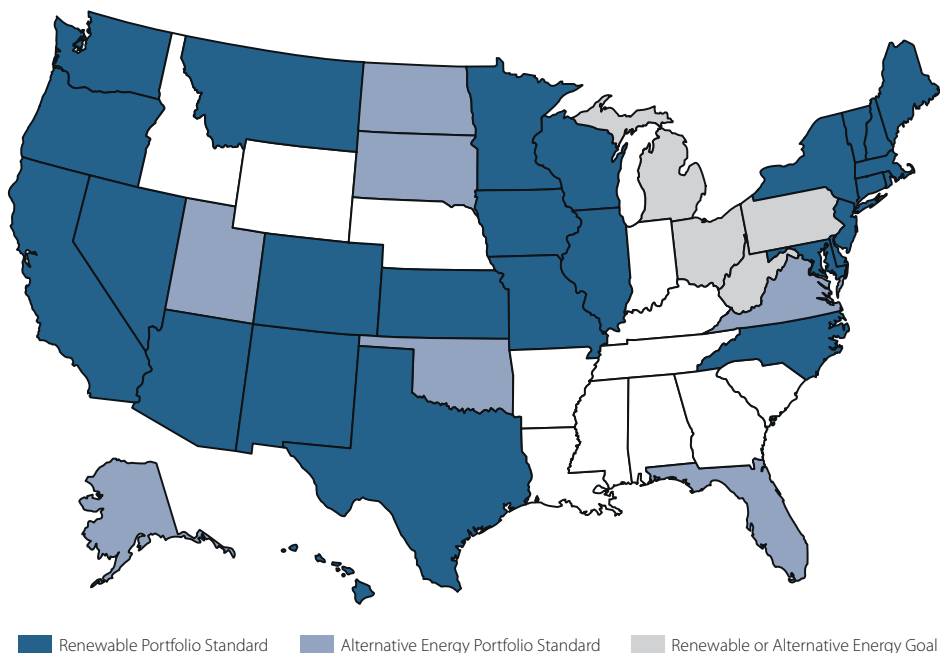
Renewable Energy:

Renewable energy, particularly solar and wind, are becoming increasingly viable options for electricity

generation as the costs of production decline. Although still a small fraction of overall U.S. energy generation, renewables have seen significant growth at a time when other energy sectors have declined. The strength of renewable technologies was demonstrated in 2008-2009, when electricity generation from renewable resources expanded by 8% in the U.S. while the total net generation declined by 4%.¹⁴³ During this period, total U.S. electricity capacity rose only 1.5% but renewable electricity capacity rose 9.2% and consumption of all major fuels also declined, but renewable energy consumption increased by 5.4%.¹⁴⁴

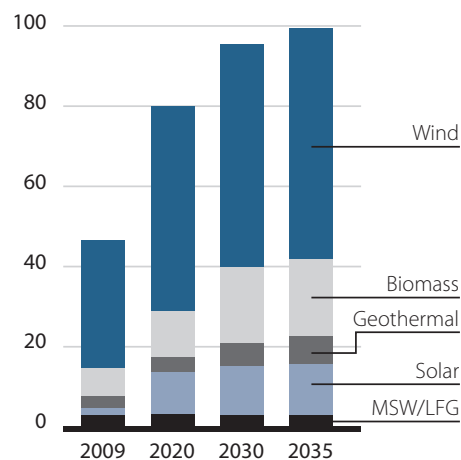
This increase is due to several factors including clean energy policies, technological development, and increased price competition. In the U.S., public policy is critical for the large-scale adoption of renewable energy technologies. Currently, 37 states and the District of Columbia have renewable mandates or Renewable Portfolio Standards (RPS), but in six states those standards are voluntary.¹⁴⁵

Table 9: Renewable & Alternative Energy Portfolio Standards ¹⁴⁶



The EIA links the continued growth of renewable energy to financial incentives and mandates such as Federal Tax Credits (FTC) and RPS.¹⁴⁷ Michigan utility CMS Energy found that it could reduce the cost of renewable energy to its customers due to “changing economic conditions, improvements in wind turbine technology, acceleration of renewable energy projects, and the extension of the production tax credit.”¹⁴⁸ The company’s CEO, John Russell, stated: “The energy law has enabled investment in renewable energy in Michigan and the creation of jobs. This revised renewable energy plan represents a significant reduction in costs to our customers.” Pew Charitable Trust also found that “where supportive clean energy policies are adopted, investment follows. Time and again, it has been shown that nations with the strongest policy frameworks have attracted the most capital and enjoyed the associated economic benefits, including job creation.”¹⁴⁹

Table 10: Renewable Capacity Growth To 2035¹⁵¹



The EIA projects growth of renewable energy through 2035, and notes that the large increase of wind capacity prior to 2012 is due to Federal Production Tax Credit expiring that year and that the largest increase in solar capacity is through 2016 due to the availability of Federal tax credits through that year.¹⁵⁰

Deutsche Bank and others hold that rates of adoption of renewable resources would increase if the U.S. develops a comprehensive energy policy “that will support renewable energy and provide more legal enforceability or ‘teeth’ than the state level RPS standards on their own, many of which are non-binding in terms of enforceability.”¹⁵²

In addition to policy, the cost of production and storage technology drives adoption of renewable energy technologies. Bloomberg New Energy Finance projects that solar technology costs, “could fall by as much as 40 percent over 2010–20 due to experience curve effects. This occurs when costs decrease as a result of efficiencies

gained through labor efficiency, network building, changes in the resource mix, standardization and/or method improvement.”¹⁵³ Solar is currently competitive with peak electricity prices in California and Japan, and the industry is driven to continue to reduce costs.¹⁵⁴ The chief executive of New Energy Finance predicts that “in a decade the cost of solar projects is going to halve again.”¹⁵⁵

Utility scale storage for intermittent sources of electricity remains a technological hurdle. Yet recent studies indicate that existing electricity grids have higher capacity to absorb intermittent resources without storage than previously considered.¹⁵⁶ The National Renewable Energy Laboratory (NREL) found that “large amounts of wind generation might be accommodated without deploying additional energy storage resources” and that the western U.S. can achieve 10-20% wind penetration by relying on natural gas to account for wind variability.¹⁵⁷ As such, the U.S. can expand its wind penetration without investing in significant utility-scale storage. As technology develops, it will be a critical element in transitioning the U.S. from fossil fuel to renewable electricity generation as it provides many benefits to the system including price arbitrage, reliability, and ancillary services.¹⁵⁸

As industry analysts conclude that reliance on coal is uneconomic for utilities, alternatives to coal for electricity generation can meet electricity needs in the short term through a blend of intermittent generation sources with natural gas as renewables reach grid parity. Long-term projections indicate increased reliance on renewable resources and improved utility-scale storage capacity replacing natural gas.

Recent studies indicate that existing electricity grids have higher capacity to absorb intermittent resources without storage than previously considered.

CONCLUSION

The risks to investors with holdings in coal mining and coal-dependent utilities are significant. Depending on the size, location, and mix of an individual utility's coal-fired utilities, the risk takes different forms but the concerns over revenue, CapEx, and growing regulatory burdens are shared. For mining companies, market changes, location, regulation, and cost of production are altering the industry's make-up, if not its fundamental purpose.

As detailed in this report, a combination of factors underscore the financial risks of continued reliance on coal for electricity generation including:

- Low natural gas and power prices;
- Coal price volatility;
- Regulatory uncertainty related to the enforcement of federal environmental laws;
- Weak economic performance and faltering electricity demand forecasts; and
- Rising construction prices due to global demand.

Investor activity identifying the financial risks related to coal-fired generation has taken several forms:

- JPMorgan Chase, Citigroup, Morgan Stanley, and other banks have adopted a set of enhanced diligence principles for power plant financing. The "Carbon Principles" are designed to raise red flags regarding the risks of investing in new carbon intensive power generation.
- Stock and credit analysts are offering more frequent and more comprehensive reporting on the topic of coal risk. Some have begun basing credit judgments on coal exposure.
- The utility markets which include investor-owned utilities, public power authorities, rural electric cooperatives, and municipal electric systems have canceled or postponed 153 new coal plant proposals. Banks, bond underwriters, and the Rural Utilities Services have all but shut down financing for new coal projects.
- Utility companies and financial underwriters are engaged in a robust discussion, based on a fairly broad consensus to replace significant portions of the nation's coal fleet with natural gas, wind, solar, and energy efficiency.

The coal industry has made recent gains in Congress, pressuring the EPA to push back some regulatory timing. However, continued uncertainty over energy policy and climate legislation does not work in the industry's favor as investments in CCS will require a substantial price on carbon to justify the high cost of the technology. Although some new coal plants are opening and some already in the pipeline are going forward, no new ones are being proposed.

A growing industry consensus is paving the way for coal plant retirements and replacement of this capacity with natural gas, renewable energy, and energy efficiency. Although there is considerable and well-founded concern about the environmental impacts of the hydraulic fracturing process used to extract shale gas, and it is likely that increased regulatory oversight will add to the cost of gas production, most experts still believe that gas prices will remain low enough to displace coal-fired electric power generation. Some utilities are responding with significant plans, some are waiting, hoping, for market and regulatory tides to switch back to coal. All are doing both, to some extent.

Depending on how investors view the material risks to the profit and loss of coal and coal-reliant industries, there are a range of actions they can take. Better understanding of coal exposure risks should prompt greater diligence by investors, their portfolio managers, and advisors. Investors should engage with management of utility companies and ask the utilities to disclose their coal exposure and address the risks with specific programs of action. Investors should also examine available options to shift their utility holdings toward companies that are reducing coal exposure risk and to avoid companies with insufficient programs to address coal's financial liabilities.

The reaction of institutional investors to the unprecedented risks that reliance on coal presents to companies and to their portfolios will determine the shape of energy investments in the U.S. in the coming decades. It will also answer the question of whether a rational, stable allocation of capital can be achieved against the backdrop of profound economic, technological, political, and environmental change that is unfolding at global, national, and local levels.

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