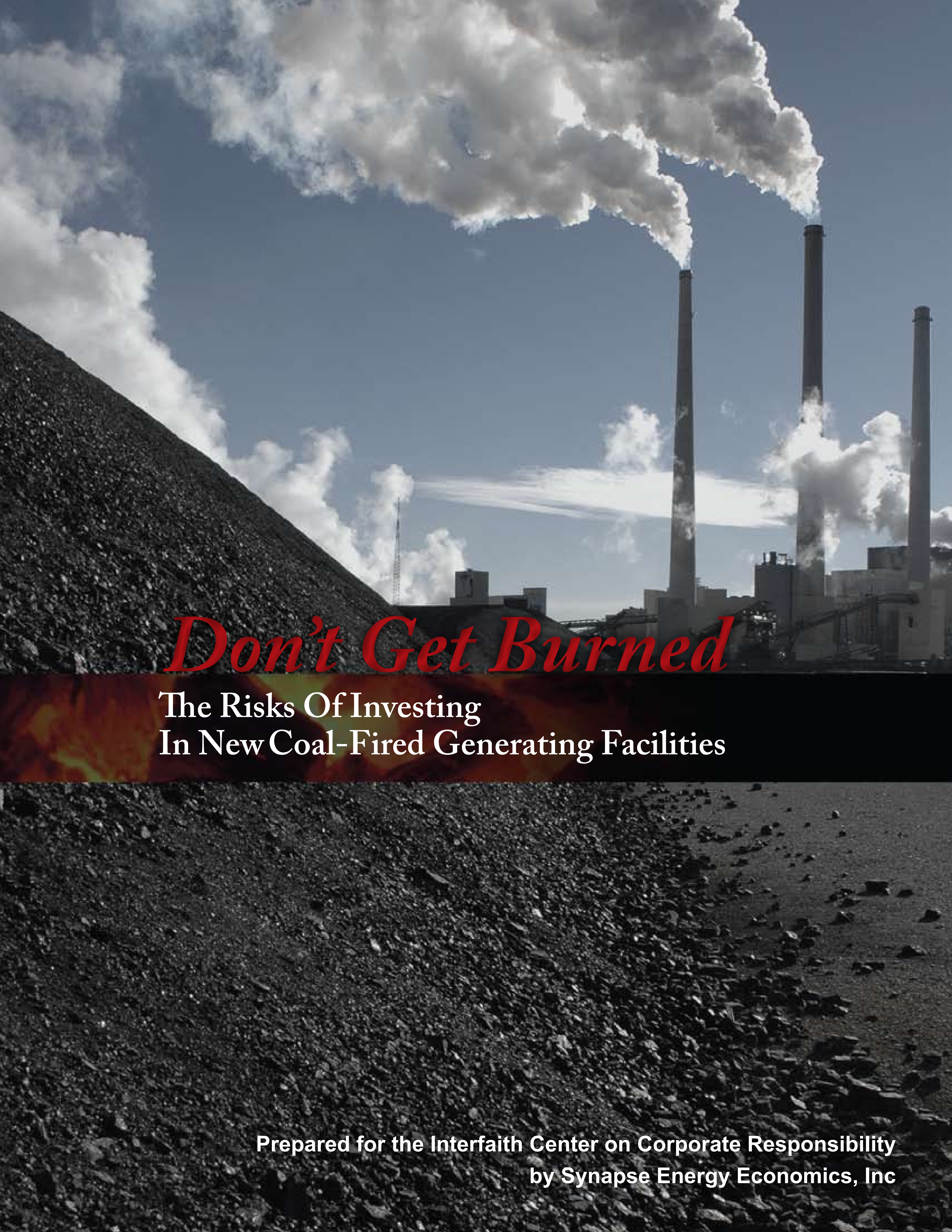

Don't Get Burned

The Risks Of Investing In New Coal-Fired Generating Facilities

Prepared for the Interfaith Center on Corporate Responsibility
by Synapse Energy Economics, Inc

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FOREWORD

Think of a freight train, hurtling across America, surging forward on gleaming rails. It's a huge and complex investment, relying on route and rails to stay as expected for a distance that exceeds the view. Now, look around the bend ahead: Can you see a gap in the rails, a sudden twist in route, an inevitable derailment? To me, proposals to put a hundred billion dollars (or is it two hundred billion dollars?) into scores of new coal fired power plants look like that train: massive, complex, hurtling forward with high momentum, and unlikely to stay on the rails.

Of course it could get worse: How soon will investors—locked into not-yet productive investments—be asked to provide a third hundred billion dollars, justified by the need to "complete partly-finished projects," started with inaccurately low projections of capital costs? Where will such funds come from? If they can be raised, how will they be recovered? When will they be recovered? Will they be recovered soon enough and fully enough to provide returns that satisfy investors' desires? If you offer advice to investors, how happy will they be with what you told them?

For large central-station coal-fired power plants, financing depends on long-term yields; thus they depend on net positive cash flow, not for years, but for decades. Operating costs and capital costs can destroy projected margins if the future differs from the past. Low depreciation rates are essential for cash-flows, and they depend on slow technology change, not just in the industry, but also in its competitors and in its customers. Overall corporate health depends on a financial flexibility that cannot co-exist with huge commitment to all-or-nothing power plants that require billions in investments before they yield their first dollars' worth of outputs. Yet, prudent viewers can already see that within the next half dozen years, there are likely to be radical changes in construction costs, operating costs, expected sales-volumes, competitive alternatives and price resistance from smart or desperate customers. These concerns call into question whether large investments in coal-generation without carbon controls are reasonable in today's industry.

These are the kinds of concerns about the viability and prudence of electric sector investments that I worried about for decades as a utility analyst and as Chairman of a state utility commission. They are the matters I heard expert testimony upon in regard to large generating stations. They are the reasons that large customers and public advocates fought rate increases, and like the reasons that I and scores of my colleagues disallowed billions of dollars of rate requests. Today these are the issues that I ponder, as a director of, and an advisor to, technology councils, engineering schools, and a research institute. And they are the concerns that investment analysts should address before, rather than after, commitments for investment in new coal-fired generation are made.

These concerns are shaped by the factors in Synapse's analysis. This analysis highlights the uncertainties surrounding investment in new coal in the current policy, technology, and market circumstances. It reminds us that fundamental business problems were what ruined investments in the American nuclear industry—an industry that was killed more by sharp eyed accountants than by activists. It notes the rapid increases in construction costs over last year, and suggests how likely they are to continue as world-demand booms for minerals, materials, and skills.

Synapse points to the obvious fact that carbon control will be required, with technologies whose effectiveness we only partly understand, and whose costs we cannot yet really estimate. It warns investors not to expect the kind of 'grandfathering' clauses that allowed continued pollution from large plants under the Clean Air Act. Why? Because many states have already made carbon-reduction commitments that fundamentally contradict increased reliance on coal-fired generation; and because the prospect of nation-wide carbon-reduction is already well past the threshold that lawyers in the future will call 'foreseeable.' It notes that the costs of controls for other pollutants, such as mercury are only now beginning to be faced. Noting that, across the spectrum, smart investors are pulling back from large coal-plants without carbon-control, it makes clear that those less-prudent may well "get burned"

This analysis will be persuasive as evidence for reviewers after-the-fact—but it will be far more valuable to those that listen to it before imprudent investments are made. We are lucky to have Synapse's work before us now, when there is still time to recognize the risks that it outlines—and time to note that other factors (such as rail costs, water limits, end-use co-generation, transmission cost-escalations, judicial over-sight of RTO pricing, and rapidly rising investments in demand control through end-use efficiency) all point in the same direction as Synapse's analysis.

For producing serious, careful, work that looks both wide and deep, we all owe Synapse a strong thanks—and we owe our clients, our fiduciaries, and those that trust us, action based upon the lessons that it offers us.

Michael Dworkin

Michael Dworkin is Professor of Law and Director of the Institute for Energy and the Environment at Vermont Law School. Professor Dworkin was Chair of the Vermont Public Service Board from 1999 to 2005 and he chaired the national utility commissioners' Committee on Energy Resource & the Environment. For his warning on cost-recovery for coal plants without carbon capture technology, see *"Old-Coal" Power Plants: Imprudent Investments?* **Science 315, 1791b (2007)**

Executive Summary

Introduction. Coal has played a major role in the electric industry, serving as the source of more than half of this country's electricity for decades. However, in recent years, a seismic shift in the understanding of energy use and its impacts, coupled with rising power plant construction costs, have exposed coal to shifting circumstances and greater risk. As a result, coal is losing its appeal as a predictable investment and is instead fraught with uncertainty. Traditionally, coal has been an abundant domestic energy source that underpinned low electricity prices; however, myriad factors, including the growing awareness of the adverse environmental impacts of burning coal—the most carbon intensive fuel—to generate electricity and rising plant construction costs have contributed to the increasing risk of investing in coal-fired power plants.

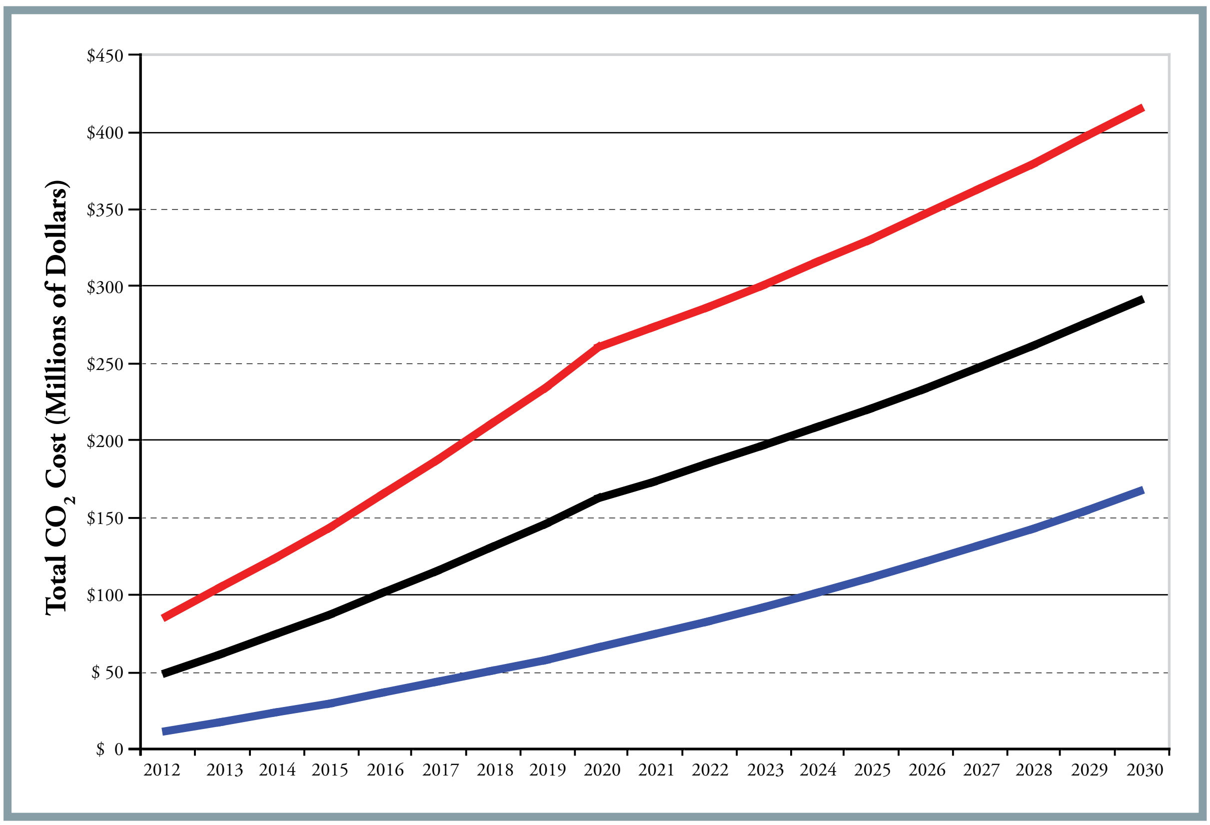
Reminiscent of nuclear power. Developments in and surrounding the coal industry today are reminiscent of conditions affecting the nuclear industry in the 1970s. Prior to the 1970s, nuclear power appeared to be a relatively low risk investment with construction and operating costs relatively stable and easy to predict. The promise of cheap, abundant, domestic energy had wide appeal. However, beginning in the 1970s construction costs in the nuclear industry became increasingly difficult to anticipate and began to spiral out of control. Numerous planned power plants were cancelled, and many utilities faced significant financial difficulties associated with their nuclear investments.

Evidence of shakiness in new coal investments. Coal is an increasingly risky long-term investment. More than twenty proposed coal-fired power plants were cancelled in 2007 and three dozen more were delayed. An increasing number of companies have announced more generally that they will not seek to build any new coal-fired power plants at this time, and some state regulators are beginning to reject coal plant investments as too risky and ill-timed for current circumstances. Myriad factors have contributed to the uncertainties surrounding investment in coal. In particular, coal fired power faces numerous uncertainties associated with the likelihood of federal greenhouse gas regulation, state regulation, the ambiguous status of technology to manage carbon emissions from fossil-fueled power plants, worldwide competition for construction resources and materials, and further restrictions on emissions of pollutants such as NO_x and SO_2.

That there will be Federal regulation of greenhouse gas emissions is certain and this will affect the ability of coal to compete. The electric industry is facing a period of unusual regulatory uncertainty because we are in transition to a new paradigm. Scientific consensus indicates that emissions of greenhouse gases jeopardize current biological, economic and social systems. It has become clear that greenhouse gas emissions must be reduced, and scientific evidence indicates that reductions of at least 60-80percent below current emissions will be necessary by the middle of this century to avoid the most dangerous impacts of climate change. Federal regulation of greenhouse gases has become a certainty; and, as a major source of greenhouse gas emissions, the electric sector will be one of the primary affected sectors. Though federal regulation of greenhouse gases is certain, program elements remain undecided, with major issues such as stringency of reductions and distribution of emissions allowances still undecided. Because the federal program is still under development, it is very difficult to anticipate what costs power plant owners and investors will face. However, due to its emissions profile, fossil-fueled generation, particularly coal, is likely to be particularly affected. Policy trends are away from provisions, such as grandfathering and free allowance allocation, that would reduce the cost impact on coal-fired power plants. Current policy proposals include more stringent emission reductions than proposals in prior Congresses, and, to a large extent, include provisions for auctioning allowances rather than granting them for free to affected emissions sources in quantities sufficient to cover all emissions.

Paying for CO_2 emission allowances is likely to have a very significant impact on the variable costs of operating new coal-fired power plants. For example, Figure ES-1 below shows what the total CO_2 costs would be, using a reasonable range of emission allowance price forecasts, for the owners of a 600 MW pulverized coal-fired power plant that operates at an average annual 85 percent capacity factor.

Figure ES-1: Total Annual CO_2 Costs – 600 MW Pulverized Coal Plant Operating at an Average 85 Percent Capacity Factor



Thus, the investor-owned utility that owned this particular plant would pay between \$11 million and \$85 million for CO_2 emissions allowances in 2012. This would increase to between \$65 million and \$259 million in 2020 and between \$166 million and \$414 million in 2030. The Synapse CO_2 price forecasts that form the basis for the annual costs shown in Figure ES-1 are substantially lower than a number of the other recent price projections. Thus, the annual CO_2 costs would be even higher if Figure ES-1 had reflected these other CO_2 price forecasts.

An increasing number of states are regulating greenhouse gas emissions. While federal regulation is still under development, many states have taken specific and concrete actions to reduce greenhouse gas emissions from the electric sector and to increase reliance on energy efficiency and renewable resources. Regional efforts to reduce greenhouse gas emissions also have been undertaken by states in the Northeastern, upper Midwest and Western areas of the nation. These state regulations and policies will affect the competitiveness of coal-fired power generation and could also modify the demand for new resources.

To remain viable, coal emissions must be reduced, but capture and storage technology is not currently commercially viable and may not be for years, or even decades. Coal-fired power generation cannot escape from the emissions characteristics of coal, notably that emissions of greenhouse gases and criteria air pollutants are high. These emissions are not compatible with current scientific conclusion that large reductions in greenhouse gas emissions are necessary. Efforts are underway to find a method to capture the greenhouse gas emissions and store them permanently in order to avoid release into the atmosphere. This method is called "carbon capture and storage" (CCS). Hopes are high for CCS technology to provide a solution for reducing the release of greenhouse gas emissions from coal. However, CCS technology is still under development, and is not ready for widespread application. Further, the economics of this solution are still uncertain, with wide ranging estimates of the costs of capturing and storing carbon. The costs of the new technology, coupled with reductions in power plant output associated with CCS, can raise generation costs at a coal-fired power plant by substantially more than 50 percent.

Several companies have decided to delay investment in new coal until there is a carbon solution. As such, future investments in coal plants hinge heavily on expectations of the availability of CCS. It is likely to be many years before CCS becomes technically and economically viable. Due to the immaturity of CCS, any claims that a plant is "carbon capture ready" is only a vague promise.

Construction costs and schedules are unpredictable and increasing. Uncertainties surrounding coal extend beyond regulatory and technological issues. These uncertainties are compounded by the worldwide competition for construction resources and materials. This competition for power plant design and construction resources, as well as for commodities and equipment, result in prices spiraling upward with unpredictable costs for plant owners and investors. Several power plant developers have cited these factors in explaining capital cost escalation in specific power plant projects. For example, according to Duke Energy Carolinas, new coal-fired power plant capital costs had increased approximately 90 to 100 percent since 2002. A large number of projects have announced significant construction cost increases over the past few years. Industry research indicates that capital costs have increased more than 50 percent in the past three years. As a result of rising capital costs, construction firms are no longer willing to commit to fixed-price contracts, instead shifting the risks of higher prices to plant owners. Regulatory uncertainty, due to the possibility that state rate regulators will disallow construction or operating costs, results in further risk exposure to power plant owners and investors.

Further regulation of other non-greenhouse gas emissions. Coal-fired power plants will also be affected by further restrictions that are either pending or proposed on NO_x, SO_2, and Mercury emissions. The Clean Air Interstate Rule includes a cap and trade mechanism to reduce emissions of NO_x and SO_2 by plants in eastern states to approximately 70 percent and 60 percent below 2003 levels once fully implemented. A companion rule, the Clean Air Mercury Rule, targets coal-fired electric plants with goals of attaining 70 percent reductions from 2003 levels once fully implemented. In addition, revisions to EPA's primary and secondary ground-level ozone standards are pending.

Investor cost recovery is uncertain. Current circumstances, and conditions in the future, may mean that investors will not be able to recover their investments in new coal-fired power plants through regulated rates or through market-based prices.

All of these factors result in a host of uncertainties surround investments in coal-fired power generation. With federal regulatory decisions imminent, but still ill-defined, state regulations that spur non-fossil resources, technologies that are promising but unready, cost and scheduling uncertainties in construction, and further emissions reductions that will cost money, the parameters of new investments in coal are difficult to pin down and anticipate with any certainty. Coal-fired power plants are surrounded by uncertainties that will affect their cost and their economic competitiveness. Investors should factor these uncertainties into their decisions about what investments are promising. The only thing that is sure is that coal, as the most carbon intensive fuel, is facing a difficult challenge in the transition to a future where carbon dioxide emissions into the atmosphere must be significantly reduced to prevent long-term harm to the planet.

Photo credit: morguefile

Introduction

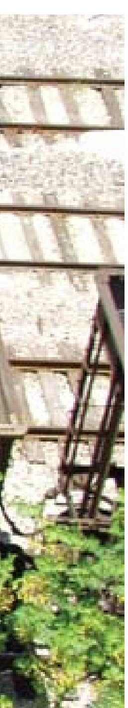
After a relatively prolonged period of quiet, the electric utility industry is again entering a period of sustained growth as concerns have been raised about reserve margins and system reliability. As part of this growth, investor owned utilities, merchant companies, and public power utilities and agencies have proposed to build over 130 new coal-fired generating plants over the next ten to twenty years. The costs of constructing and operating these plants are highly uncertain due to multiple factors in the industry, and the owners will face significant financial, economic and environmental risks. In particular, investments in these plants will be at risk if the utilities and/or companies are unable to recover all of the costs from customers and earn forecast profits.

A. Historical Perspective—Déjà Vu All Over Again?

Until the 1970s, building new nuclear power plants appeared to be a relatively low risk investment because construction and operating costs were relatively stable and easy to predict. However, starting in the 1970s, the costs of building new nuclear power plants began to spiral out of control. As a result, the actual costs of new plants were two to three times higher than the costs that had been estimated during licensing or at the start of construction.

These cost increases led to significant financial problems for the utilities that were building the nuclear power plants. For example:

- Public Service Company of New Hampshire went bankrupt due to financing difficulties associated with the Seabrook Nuclear Plant.
- Long Island Lighting Company ("LILCO") nearly went bankrupt due to the Shoreham nuclear plant. It eventually sold the $5 billion Shoreham plant to the State of New York for $1. LILCO's share price dropped from high of $19.75 in 1978 to less than $7 in 1984. The company eventually was taken over the Long Island Power Authority in 1998.
- Consumers Power nearly went bankrupt due to its Midland nuclear plant. Midland was originally estimated to open in 1975 and cost about $500 million. Ten years and $3.5 billion later, Consumers Power cancelled the unfinished plant. Its stock dropped from $55 per share pre-Midland to just above $5 per share. It was forced to suspend common stock dividends at one point.
- In 1983, the Washington Public Power Supply System (WPPS) defaulted on $2.25 billion in municipal bonds after it failed to complete construction of two nuclear power plants. It has become the largest municipal default in U.S. history. In June 2007, after protracted legal battles, the Washington State Supreme Court ruled that public utilities did not have to pay their share of the loss. With a current debt of $8.3 Billion, a Washington State legislator observed "default is now pretty much assured, and bankruptcy is more likely."



These cost increases also led to massive write-offs and regulatory disallowances:

- From 1984 to 1993, electric utilities with nuclear construction projects wrote off in excess of $17 billion, net of tax effects, for abandoned plants and regulatory disallowances.
- In 1980s alone, state commissions disallowed from utility rate base more than $7 billion of nuclear costs due to construction imprudence.
- Another $2 billion in nuclear costs were disallowed due to imprudence of building new capacity that was not used and useful when completed.

This history of nuclear investments is important because investments in companies that are now proposing to build new coal-fired power plants face comparable risks and uncertainties:

1. The likelihood of federally-mandated reductions in greenhouse gas emissions leading to high costs for carbon-emitting resources.
2. State mandated reductions in greenhouse gas emissions and the adoption of policies promoting increased use of energy efficiency and renewable resources that will reduce the need for new power generation and adversely affect the relative economics of proposed coal-fired power plants.
3. The uncertainties surrounding the technical and economic viability of carbon capture and sequestration for pulverized coal-fired power plants.
4. Skyrocketing plant construction costs and delayed construction schedules as a result of the worldwide competition for power plant design and construction resources, commodities and equipment.
5. More stringent regulation of the current criteria pollutants.

The potential for coal price increases and supply disruptions also are risks associated with investments in new coal-fired power plants. For example, train derailments in 2005 resulted in severe disruptions in the supply of coal from the Powder River Basin (PRB) in Wyoming to utilities throughout the Midwest. A number of companies have reported that these disruptions led to higher fuel costs, burn restrictions at some plants and a scrambling for new supplies from as far away as South America.[1]

The railroads have said that they are making substantial investments to improve their capability to the transport coal out of the Powder River Basin. Time will tell whether these investments are effective in improving the reliability of the rail transport and in keeping up with the increasing demands for coal from the PRB.[2] However, the transport of coal from the PRB still will be controlled by a small number of railroads. This could lead to substantial increases in the ultimate cost of fuel for new and existing coal-fired power plants.

B. Proposed Coal-Fired Power Plants Are Being Cancelled, Delayed and Rejected Due to Cost and Regulatory Uncertainty

An increasing number of companies, public power utilities and regulatory commissions are factoring these uncertainties and trends into their planning for new fossil-fired power plants. As a result, a large number of proposed plants have been cancelled, delayed or rejected. For example, more than twenty proposed coal-fired power plants also were cancelled in 2007, and more than three dozen other plants were delayed. For example:

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- Rocky Mountain Power, a division of PacifiCorp, cancelled two proposed coal plants. The Company explained the basis for this decision in a November 28, 2007 letter to the Public Service Commission of Utah:

> Furthermore, due to the current uncertainty in the ability to quantify in any meaningful way the cost of compliance with potential federal CO_2 legislation, Bridger 5 as a supercritical unit is no longer a viable option for 2014. Within the last few months, it has become apparent that Congress will enact some restriction upon carbon emissions, but the project cost impact upon new coal generation is currently within such a wide range as to make meaningful risk assessment futile. On November 13, 2007, the National Association of Regulatory Utility Commissioners adopted its first resolution acknowledging that climate change legislation addressing carbon emissions will occur. Within the last few months, most of the planned coal plants in the United States have been cancelled, denied permits, or been involved in protracted litigation. Accordingly, the Company submits that IPP 3, Bridger 5, and the IGCC option at Jim Bridger are no longer viable options for [its] 2012 RFP for the 2012 and 2014 time frame, respectively.
>
> While the Company is not excluding new coal generation ownership from its 20 year options, absent some change in conditions, it cannot be determined at this time whether new coal generation will satisfy the least cost, least risk standards that would enable us to consider it as a viable option within our ten year plans.[3]

- Tenaska Energy cancelled plans to build a coal-fired power plant in Oklahoma in July 2007 because of rising steel and construction prices. According to the Company's general manager of business development:

> ".. coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.
>
> And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot… At

one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.

We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it."[4]

- Westar Energy announced in December 2006 that it was deferring site selection for a new 600 MW coal-fired power plant due to significant increases in the facility's estimated capital cost of 20 to 40 percent, over just 18 months. This prompted Westar's Chief Executive to warn: "When equipment and construction cost estimates grow by $200 million to $400 million in 18 months, it's necessary to proceed with caution."5 As a result, Westar Energy has suspended site selection for the coal-plant and is considering other options, including building a natural gas plant, to meet growing electricity demand. The company also explained that:

  most major engineering firms and equipment manufacturers of coal-fueled power plant equipment are at full production capacity and yet are not indicating any plans to significantly increase their production capability. As a result, fewer manufacturers and suppliers are bidding on new projects and equipment prices have escalated and become unpredictable.[6]

- TXU cancelled 8 of 11 proposed coal-fired power plants in the spring of 2007, in large part because of concern over global warming and the potential for federal legislation restricting greenhouse gas emissions.[7]
- Tampa Electric cancelled a proposed integrated gasification combined cycle plant (IGCC) in the fall of 2007 due to uncertainty related to CO_2 regulations, particularly capture and sequestration issues, and the potential for related project cost increases. According to a press release, "Because of the economic risk of these factors to customers and investors, Tampa Electric believes it should not proceed with an IGCC project at this time," although it remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation.[8]
- In June 2007, the Tondu Corp. announced that it was suspending plans to build a planned 600 MW IGCC facility in Texas citing high costs and other concerns related to technology and construction risks.[9]

A number of utilities also have announced that they will not seek to build any more new coal-fired power plants at this time. For example:

- In its November 2007 Resource Plan, Public Service of Colorado concluded that:

  > In sum, in light of the now likely regulation of CO_2 emissions in the future due to a broader interest in climate change issues, the increased costs of constructing new coal facilities, and the increased risk of timely permitting to meet planned in-service dates, Public Service does not believe it would be prudent to consider at this time any proposals for new coal plants that do not include CO_2 capture and sequestration.[10]

- In its 2007 Resource Plan, filed in December 2007 in Minnesota, Xcel Energy similarly noted that "given the likelihood of future carbon regulation, we have only modeled a future coal-based resource option that includes carbon capture and storage."[11] Xcel Energy also noted in its 2007 Minnesota Resource Plan that "Adding coal resources without sequestration would significantly add carbon and risk for our ratepayers."[12]

- Minnesota Power Company has announced that it is considering only carbon minimizing resources and would not consider a new coal resource without a carbon solution.[13] The Company also said that in the long-term it would consider pulverized coal and IGCC plants but only with proven carbon capture and CO_2 sequestration technologies.[14]

- Idaho Power Company is another company steering clear of coal for now, concluding that:

  > Due to escalating construction costs, the transmission cost associated with a remotely located resource, potential permitting issues, and continued uncertainty surrounding GHG laws and regulations, IPC [Idaho Power Company] has determined that coal-fired generation is not the best technology to meet its resource needs in 2013. IPC has shifted its focus to the development of a natural gas-fired combined cycle combustion turbine located closer to its load center in southern Idaho.[15]

- Avista Utilities also has announced that does not anticipate pursuing coal-fired power plants in the foreseeable future.[16]

Regulatory commissions and agencies also have begun to reject proposed coal-fired power plants, in part, because of concerns about cost uncertainties or about the threat posed by global climate change.

Regulatory commissions and agencies also have begun to reject proposed coal-fired power plants, in part, because of concerns about cost uncertainties or about the threat posed by global climate change. For example, since last December, proposed coal-fired power plant projects have been rejected by the Oregon Public Utility Commission, the Florida Public Service Commission, the Oklahoma Corporation Commission[17], and the Kansas Department of Health and Environment. The North Carolina Utilities Commission rejected one of the two coal-fired plants proposed by Duke Energy Carolinas for its Cliffside Project.[18]

More specifically, the June 2007 decision of the Florida Public Service Commission in denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties over plant costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.[19] The Minnesota Public Utilities Commission also has refused to approve an agreement under which Xcel Energy would have purchased power from a proposed IGCC facility due to concerns over the uncertainties surrounding the plant's estimated construction and operating costs and operating and financial risks.[20]

In another example, in mid-October 2007, the Kansas Department of Health and Environment rejected an application to build two 700 MW coal-fired units at an existing power plant site. In a prepared statement explaining the basis for this decision, Rod Bremby, Kansas's secretary of health and environment noted that "I believe it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing."[21]

While investments in alternatives energy sources also face risks, zero emitting renewable resource and energy efficiency measures do not face the economic risks of federally mandated reductions in greenhouse gas emissions.

Investments in the alternatives to new coal-fired power plants also face risks, such as potential construction cost increases, that also need to be considered in any assessment of the relative risks of different investments. However, zero emitting renewable resource and energy efficiency alternatives do not face the economic risks associated with federally mandated reductions in greenhouse gas emissions.

Photo credit: morguefile

Federally Mandated Reductions in Greenhouse Gas Emissions

A. Federal Regulation of CO_2 and Other Greenhouse Gas Emissions is a Matter of When, Not If

For years, there has been a debate over whether the federal government will regulate the emissions of greenhouse gases from fossil-fired power plants. This debate is over. Trends in this country are towards greater awareness of climate systems, increasing concern over potential dangerous degrees of climate change, stronger resolve for mandatory policies, and more aggressive reduction targets to avoid dangerous climate change. Climate change is emerging as a factor in a growing number of policy areas, including national security, water management, insurance, and management of public lands.

Growing public and private awareness are creating pressure for effective policy, and Congress is increasingly active in its consideration of various impacts of climate change on the U.S. and various means of mitigating this country's contribution to greenhouse gas (GHG) emissions. Increasing numbers of states are adopting policies and participating in regional initiatives to reduce greenhouse gas emissions. As public and private sector pressure for a federal mandatory emissions reduction policy mounts, federal legislators are considering increasingly stringent emissions reductions targets, which will have significant impacts on the future use of coal in the United States. The future of coal, the most carbon intensive fuel, is inextricably intertwined with the future of climate change policy.

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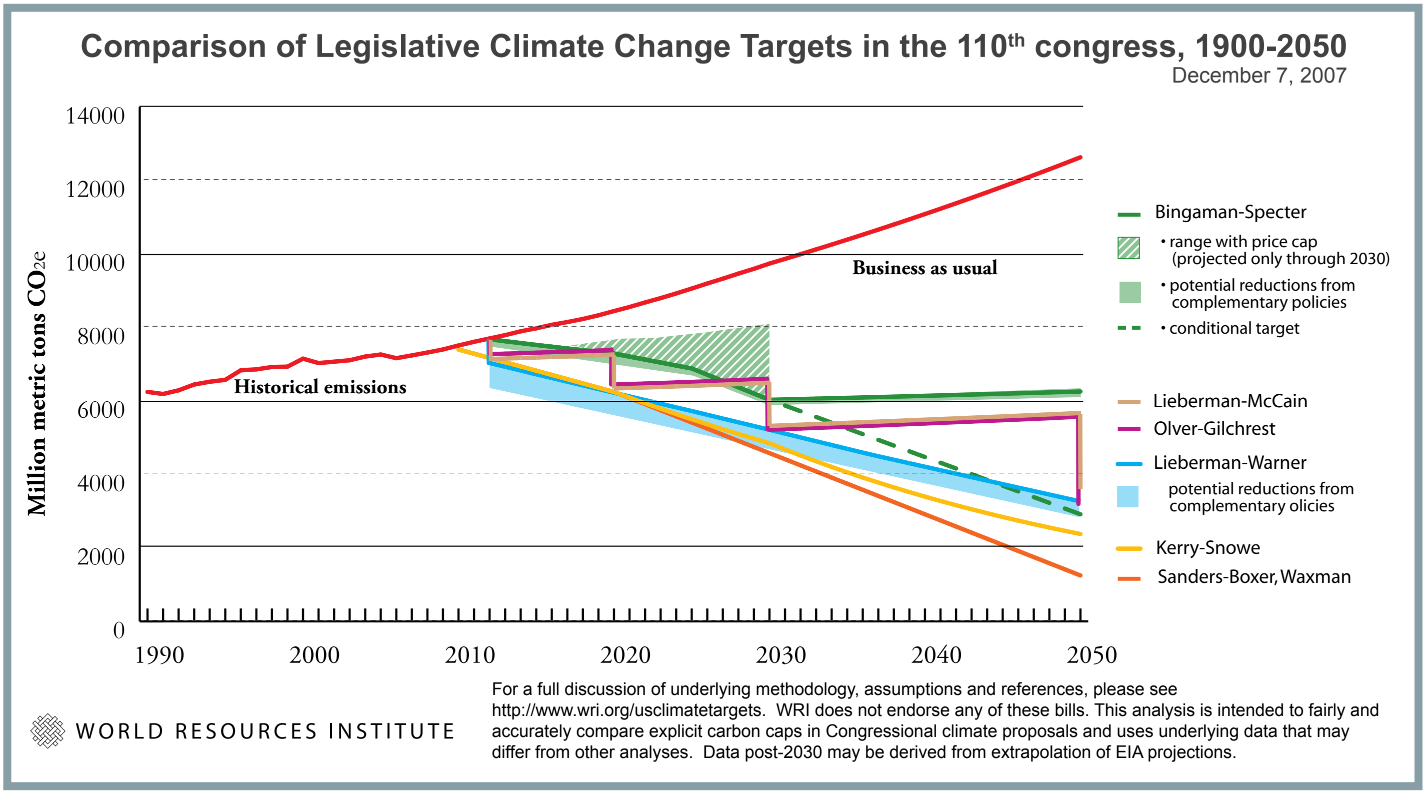
To date, the U.S. government has not required greenhouse gas emission reductions. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. The federal proposals that would require greenhouse gas emission reductions that had been submitted in the current U.S. Congress are summarized in Table 1 (*p14*).

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in the current U.S. Congress[22]

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein- Carper .317	Electric Utility Cap & Trade Act	2007	2006 level by 2011, 2001 level by 2015, 1%/year reduction from 2016-2019, 1.5%/ year reduction starting in 2020	Electricity sector
Kerry-Snowe S.485	Global Warming Reduction Act	2007	2010 level from 2010-2019, 1990 level from 2020-2029, 2.5%/year reductions from 2020-2029, 3.5%/year reduction from 2030-2050, 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	2004 level in 2012, 1990 level in 2020, 20% below 1990 level in 2030, 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	2%/year reduction from 2010 to 2020, 1990 level in 2020, 27% below 1990 level in 2030, 53% below 1990 level in 2040, 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	Cap at 2006 level by 2012, 1%/year reduction from 2013-2020, 3%/year reduction from 2021-2030, 5%/year reduction from 2031-2050, equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	2012 levels in 2012, 2006 levels in 2020, 1990 levels by 2030. President may set further goals ≥60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	2005 level in 2012, 1990 level in 2020, 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.

The emissions levels that would be mandated by the bills that have been introduced in the current Congress are shown in Figure 1:

Figure 1: Emissions Reductions Required under Climate Change Bills in Current US Congress



These bills increasingly aim for emissions reductions of 60 percent to 80 percent from current levels by 2050 based on the scientific conclusion that these levels of reductions will be necessary to stabilize atmospheric CO_2 concentrations at levels likely to avoid the most dangerous impacts of climate change.

It is important to emphasize that federal legislative proposals from the past few years have included increasingly stringent emission reduction requirements. Prior to early 2006, the most aggressive legislative proposal was to cap emissions at 1990 levels (that is, the 2003 version of the McCain-Lieberman proposal, S. 139). As shown in Figure 1, most proposals in the current 110th U.S. Congress have included more aggressive emission reduction targets in the neighborhood of reducing greenhouse gas emissions 60-80 percent below 1990 emissions levels by about 2050.

Proposals in the current 110th U.S. Congress have included aggressive emission reduction targets in the neighborhood of reducing greenhouse gas emissions 60-80 percent below 1990 emissions levels by about 2050.

Though there is uncertainty surrounding the form and timing of a federal mandatory reduction program, three things are certain. First, federal regulation of greenhouse gas emissions is a question of when, not if. Second, the electric sector will be a primary focus of any such program in part because of its substantial contribution to overall U.S. CO_2 emissions and, in part, because of the relative ease of regulating emissions from point sources like power plants. Third, because coal is the most carbon intensive fuel, emissions from coal-fired power plants will have to be significantly reduced as part of a federally-mandated program.

B. There is Great Uncertainty Regarding Future CO_2 Emissions Allowance Prices

If, as is currently anticipated, federal regulation of greenhouse gas emissions involves the creation of a national cap-and-trade program, the economics of proposed coal-fired power plants will be affected by the prices that the owners will have to pay for allowances to emit CO_2 from their plants. As shown in Table 2, there are a number of factors that will affect projected allowance prices: the base case emissions forecast; whether there are complementary policies such as aggressive investments in energy efficiency and renewable energy independent of the emissions allowance market; the policy implementation timeline; the reduction targets in a proposal; program flexibility involving the inclusion of offsets (perhaps international) and allowance banking; technological progress; and emissions co-benefits.[23] In particular, we at Synapse anticipate that technological innovation will temper allowance prices in the out years of our forecast.

Table 2. Factors That Affect Future Carbon Emissions Policy Costs

Assumption	Increases Prices if…	Decreases Prices if…
"Base case" emissions forecast	Assumes high rates of growth in the absence of a policy, strong and sustained economic growth	Lower forecast of business-as-usual emissions
Complimentary policies	No investments in programs to reduce carbon emissions	Aggressive investments in energy efficiency and renewable energy independent of emissions allowance market
Policy implementation timeline	Delayed and/or sudden program implementation	Early action, phased-in emissions limits
Reduction targets	Aggressive reduction target, requiring high-cost marginal mitigation strategies	Minimal reduction target, within range of least-cost mitigation strategies
Program flexibility	Minimal flexibility, limited use of trading, banking and offsets	High flexibility, broad trading geographically and among emissions types including various GHGs, allowance banking, inclusion of offsets perhaps including international projects
Technological progress	Assume only today's technology at today's costs	Assume rapid improvements in mitigation technology and cost reductions
Emissions co-benefits	Ignore emissions co-benefits	Includes savings in reduced emissions of criteria pollutants

A number of recent studies have examined the allowance prices that would be required to achieve the emissions reduction targets in the global warming legislation that has been introduced in the current Congress. These studies include:

- Analyses of Senate Bill S.280, the Climate Stewardship and Innovation Act, introduced in 2007 by Senators McCain and Lieberman, by the U.S. Environmental Protection Agency ("EPA") and the Energy Information Administration of the U.S. Department of Energy ("EIA").[24] The EPA examined seven different scenarios reflecting a range of assumptions concerning such important factors as the levels of offsets that would be allowed and the assumed levels of nuclear generation. The EIA examined eight different scenarios.

- Analyses of Senate Bill S. 1766, the "Low Carbon Economy Act" introduced by Senators Bingaman and Specter, by the EIA.

- An Assessment of U.S. Cap-and-Trade Proposals published in April 2007 by the MIT Joint Program on the Science and Policy of Global Change. This Assessment evaluated the impact of the greenhouse gas regulation bills that are being considered in the current Congress.[25] These three core scenarios analyzed in the MIT Assessment included (1) a reduction of greenhouse gas emissions of 80 percent from current levels by 2050; (2) a reduction of greenhouse gas emissions of 50 percent from current levels by 2050; and (3) stabilization of CO_2 emissions at year 2008 levels. The MIT Assessment also examined the impact of changes in important assumptions in additional sensitivity scenarios.

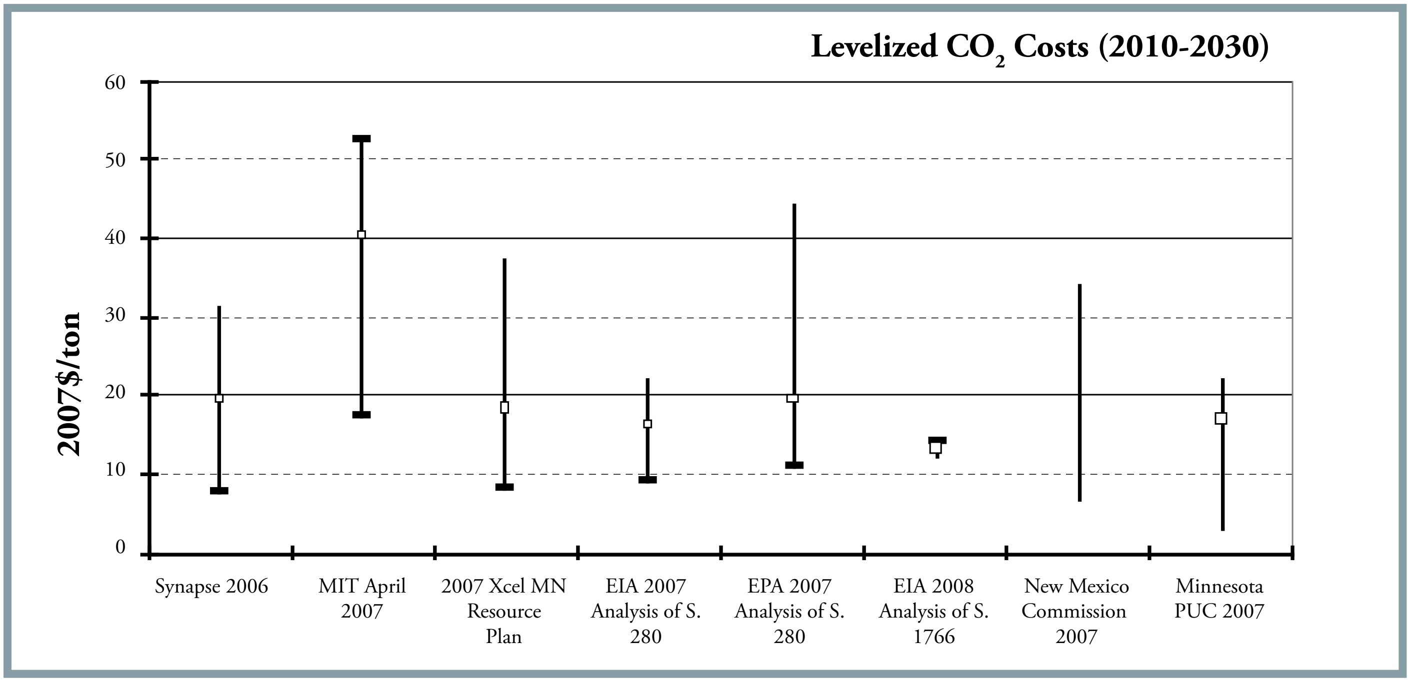
The ranges of CO_2 allowance prices from these studies are presented in Figure 2. This Figure also includes the safety valve allowance prices included in Senate Bill S. 1766, the Low Carbon Economy Act, which is the global warming legislation submitted in July by Senators Bingaman and Specter. These safety valve prices would start at $12/ton in 2012 and escalate at a real rate of 5 percent per year.

Because of the uncertainty concerning the levels of future CO_2 emissions allowance prices, regulatory commissions and utilities are increasing looking at a wide range of CO_2 emissions allowance prices in their resource planning. For example, the New Mexico Public Regulation Commission has ordered that utilities should consider a range of CO_2 prices in their resource planning.[26] This range runs from $8 to $40 per metric ton, beginning in 2010 and increasing at the overall 2.5 percent rate of inflation. The Minnesota Public Utilities Commission has similarly directed that utilities consider in their resource planning a range of CO_2 prices from $4/ton to $30/ton that would begin in 2012.[27] Similarly, Xcel Energy has recently announced that it would use a range of $9/ton to $40/ton, also beginning in 2010, in its resource planning.[28] These prices also would escalate at the overall rate of inflation.

Synapse Energy Economics developed a set of high, mid and low CO_2 emission allowance prices that we recommend be used in resource planning. Although these CO_2 prices were developed in the spring of 2006, we believe that they remain reasonable, even conservative, considering the more stringent legislative proposals that have been submitted in the current Congress and other regulatory and industry developments.

The ranges of CO_2 prices from each of these sources are presented in Figure 2, on a levelized basis, in year 2007 dollars.

Figure 2: Recent CO_2 Price Forecasts



Despite this evidence that future CO_2 prices may be quite significant, many companies still manage to reduce the impact of CO_2 prices in their resource planning by doing some or all of the actions identified in Table 3 (*p19*). This leads to risky and imprudent investments.

Some companies do adequately consider in their resource planning the risks associated with future federal regulation of greenhouse gas emissions. Figure 3 (*p19*) shows the difference in approach to addressing the risks associated with federal regulation of greenhouse gas emissions between one utility, Xcel Energy, which considers the risk real and, therefore, looks at a wide range of possible CO_2 prices in its resource planning and another company in the Midwest that does not.

Table 3: How Some Companies Make CO_2 Prices Not Count in Resource Planning

1.	Arguing that CO_2 prices are too uncertain to use in resource planning – thereby assuming that CO_2 costs will be zero throughout 40-60 year operating lives of proposed generating facilities.
2.	Assuming CO_2 costs only as sensitivity analyses – not in base case studies.
3.	Using that only a single, low CO_2 price trajectory, not a range of possible CO_2 prices.
4.	Assuming that new units will be grandfathered, in part or in whole, under federal legislation.
5.	Screening out zero- or low-carbon emitting resources prior to running capacity planning model. Therefore, only a few non-carbon emitting resources are made available for the model to select as part of a lowest cost resource portfolio.
6.	Creating resource portfolios by hand rather than allowing the planning model to select the supply and demand side alternatives for the lowest cost plan.
7.	Assuming unreasonably high capital costs for non-coal-fired alternatives such as wind and natural gas.
8.	Assuming unreasonably high natural gas prices.
9.	Failing to consider the full achievable energy efficiency potential.
10.	Failing to increase their avoided costs for energy efficiency to reflect the cost of CO_2 regulations.
11.	Assuming that CO_2 prices do not reflect any increases, over time, of the stringency of regulation.
12.	Assuming delayed adoption or implementation of CO_2 regulations, e.g., not starting until 2015.
13.	Focusing on decreasing carbon intensity (lbs per MWh) instead of reducing overall CO_2 emissions.

Figure 3: CO_2 Prices Used in Resource Planning—Xcel Energy and Other Midwest Utility

As can be seen, Xcel Energy considers three sets of CO_2 prices. These begin at $9/ton, $20/ton and $40/ton in 2010 and escalate at the overall rate of inflation. The other Midwest utility assumes that CO_2 prices either will be zero or assumes in its "high" forecast that CO_2 prices will remain flat, in nominal terms, at $9/ton. It is not surprising, therefore, that Xcel Energy has decided not to pursue any new coal-fired power plant projects for the near future while the other utility is continuing its participation in a 500 MW pulverized coal plant.

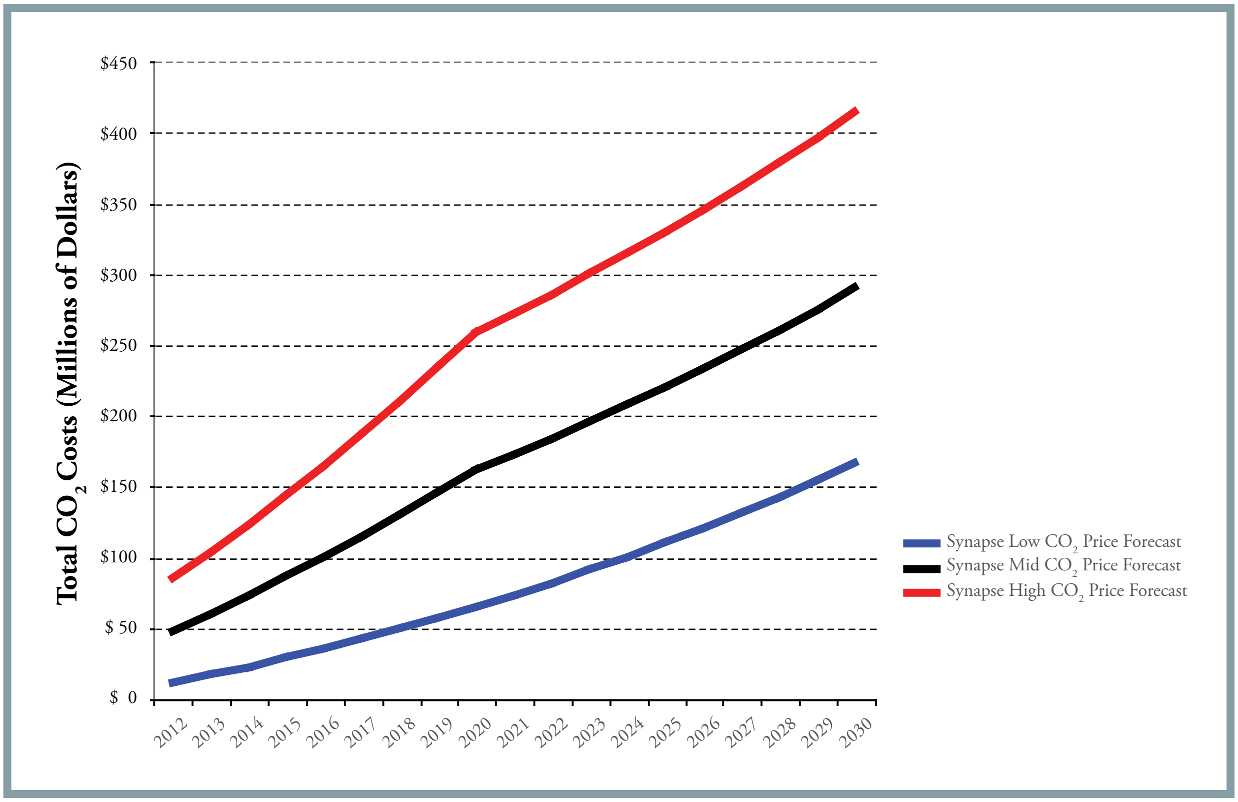
Using faulty assumptions to justify the economics of coal-fired power plants against portfolios that would include energy efficient, renewable resources is a mistake and could adversely affect companies, their investors and their customers.

Companies use some or all of faulty assumptions listed in Table 2 to justify the economics of their proposed coal-fired power plants against portfolios that would include energy efficient, renewable resources such as wind, biomass and solar, and, to the extent necessary, natural gas-fired facilities. This is a mistake and could adversely affect the companies, their investors and their customers by encouraging them to make investments that would be uneconomic if a broader range of CO_2 prices and alternatives were considered.

Paying for CO_2 emission allowances is likely to have a very significant impact on the variable costs of operating new coal-fired power plants under any of the price forecasts presented in Figure 2 above. For example, Figure 4 (p21) shows what the total CO_2 costs would be, using the Synapse low, mid and high price forecasts, for the owners of a 600 MW pulverized coal-fired power plant that operates at an average annual 85 percent capacity factor.


Photo credit: morguefile

Figure 4: Total Annual CO_2 Costs—600 MW Pulverized Coal Plant Operating at an Average 85 Percent Capacity Factor



Thus, the ratepayers of the investor-owned utility that owned this particular plant would pay between $11 million and $85 million for CO_2 emissions allowances in 2012. This would increase to between $65 million and $259 million in 2020 and to between $166 million and $414 million in 2030. Most importantly, as can be seen from Figure 2, the Synapse CO_2 price forecasts are substantially lower than a number of the other recent price projections. Thus, the annual CO_2 costs would be even higher if Figure 4 had reflected these other CO_2 price forecasts.

C. It is Not Certain that Large Numbers of Free Emissions Allowances will be Allocated to Generators and that New Plants will be Grandfathered

As noted in Table 3, Item 4 above, some companies argue that the relative economics of their proposed plants will not be affected by cost of CO_2 allowances because they assume that their new facilities will be grandfathered under federal legislation or somehow granted large numbers of free allowances. For example, the co-owners of the proposed Big Stone II Project in South Dakota have recently argued that they will be allocated free roughly 50 percent of the emissions allowance they will need for the first half of the proposed plant's book life.[29] The Big Stone II Co-owners also argued that they can expect to cover an additional 15 percent of the proposed plant's allowance needs with potentially lower cost domestic offsets.[30]

However, the numbers of free allowances and domestic offsets that will be available to new coal-fired power plants are very uncertain. In fact, new legislative proposals cite a variety of factors to consider in the distribution of allowances, a change from prior cap and trade programs where allowances were given for free to affected sources.

In fact, a number of recent developments raise serious doubts that any new power plants source could count on substantial numbers of free allowances as a compliance path. For example, most of the current legislative proposals, if not all, include some provision for allowance auctions. The Feinstein-Carper "Electric Utility Cap and Trade Act of 2007" increases the allowance auction from 15 percent in 2011 to 100 percent in 2036. The Bingaman-Specter "Low Carbon Energy Act of 2007" would increase the auction from 24 percent of allowances in 2012-2017 to 53 percent in 2030. And the Lieberman-Warner "Climate Security Act of 2007" would increase the auction from 26.5 percent of allowances in 2012 to 69.5 percent in 2031-2050.

Although, the Lieberman-Warner "Climate Security Act of 2007" would give new entrant fossil-fired power plants the first right to the emissions allowances allocated to the electric sector, it is unclear, at this time, what practical impact this provision would have. Any allowances given to such new entrants would not be available to currently existing coal- and natural gas-fired power plants. Thus, many companies that would receive free allowances under this provision, at the same time, might be losing allowances that they would otherwise receive to cover emissions from their existing power plants. Thus, there would not be a net gain for emitters of CO_2. Also the Lieberman-Warner proposal is unfair because low and non-CO_2 emitting resources, such as wind, biomass and nuclear, would not be eligible for such new entrant preference. This suggests that the first preference for new entrants may be radically changed or deleted altogether before a climate change bill is ultimately approved by Congress and signed by the President.

The Regional Greenhouse Gas Initiative (RGGI) is a multi-year cooperative effort to design a regional cap and trade program initially covering CO_2 emissions from power plants in the Northeastern States. In December 2005, the states agreed that a minimum of 25 percent of each state's emissions budget will be allocated to support consumer benefit purposes.[31] Individual states are currently conducting proceedings to develop state implementation rules; several of the states (such as NY, ME, VT and MA) are considering auctioning 100 percent of allowances.

This trend is fueled in part by experience in the European Union with carbon trading. The research department of Germany's Deutsche Bank released a report, based on analysis of the first few years, and recommendations for the future on the EU carbon emissions trading system; the analysis concludes that power generation companies have been reaping windfall profits in the first trading period, and the report recommends the use of auctions for distributing allowances in subsequent trading periods.[32]

The bi-partisan National Commission on Energy Policy, in its "Recommendations to the President and the 110th Congress," has changed its recommendation on allowance distribution so that no more than 50 percent of allowances would be distributed free of charge initially (up from 10 percent in December 2005 recommendation). The new report includes several recommendations designed to ensure that CCS is included in any new coal plant, including a specific recommendation that new coal without CCS not be allocated free allowances (NCEP recommendations to President and 110th Congress, pages 21-22).

Several legislative proposals include specific provisions pertaining to coal-fired facilities. For example, "Clean Power Act of 2007," introduced by Vermont Senator Sanders, prohibits recovery of compliance costs for conventional coal (CC) in regulated rates (except if regulator determines that no alternative exists to CC) for facilities entering operation after January 1, 2009.

A recent MIT study, *The Future of Coal: Options for a Carbon-Constrained World*, has noted that:

> There is the possibility of a perverse incentive for increased early investment in coal-fired power plants without capture, whether SCPC or IGCC, in the expectation that the emissions from these plants would potentially be "grandfathered" by the grant of free CO_2 allowances as part of future carbon emissions regulations and that (in unregulated markets) they would also benefit from the increase in electricity prices that will accompany a carbon control regime. Congress should act to close this "grandfathering" loophole before it becomes a problem.[33]

Additionally, it has been proposed in Congress that new coal-fired plants would be required to actually have carbon capture and sequestration technology. For example, the "Clean Coal Act of 2007," introduced by Massachusetts Senator Kerry, would limit CO_2 emissions from new coal-fired facilities to 285 lbs/MWh.[34] New coal-fired facilities would be defined as those that begin construction on or after April 26, 2007, and would certainly include all of the proposed coal-fired power plants that have not yet been permitted or that have not started construction.


Photo credit: morguefile

State Actions that Would Adversely Affect the Need for and the Relative Economics of Coal-Fired Power Plants

At the same time that emission reductions are being considered in Congress, many states are pursuing policies and actions to reduce greenhouse gas emissions and electricity loads and to increase the use of renewable resources. The policies that individual states are adopting to address climate change are either (1) direct policies that require specific emissions reductions from electric generation sources and (2) indirect policies that affect electric sector resource mix by promoting energy efficiency and the increased use of zero- or low-emission electric sources. Some states also have undertaken legal actions or encouraged voluntary programs of educational efforts and energy planning. More than 30 states have developed or are developing climate change plans.

For example, Table 4 (*p26*) summarizes the greenhouse gas emission reductions that have been adopted to date by 17 states. Initiatives to achieve these reductions are also underway in many of these states. Table 4 also identifies a states' participation in a regional greenhouse gas reduction program. The evolving patchwork of state and regional initiatives is creating increasing pressure, indeed requests, for federal program.

More than 30 states have developed or are developing climate change plans.

Indeed, ten states already have adopted climate change plans. Plans are currently under development in another 18 states.

An increasing number of states also have adopted policies to promote the increased use of energy efficiency and renewable resources. For example, as of December 2007, twenty-five states have adopted Renewable Portfolio Standards that require certain percentages of renewable resources in the future. Another four states have adopted goals, rather than formal standards, for the use of renewable resources.

Also, a number of states have adopted explicit performance standards regarding long-term investments in baseload generation. For example, the state of California established a greenhouse gas emissions performance standard in 2006 for long-term investments in baseload generation by the state's publicly-owned utilities either through ownership or long-term contract. The standard for baseload generation, established by the California Energy Commission, is 1,100 lbs CO_2 per MWh. Investments in baseload generation that must comply with the emission performance standard include construction or purchase of new power plants, purchase of existing power plants, and capital investments in existing, utility-owned power plants (other than routine maintenance).[35] The states of Oregon, Washington and Montana have adopted similar emission performance standards that appear to prevent the building of new coal-fired generation without some amounts of carbon capture and sequestration.

As of December 2007, twenty-five states have adopted Renewable Portfolio Standards that require certain percentages of renewable resources in the future.

Table 4: Announced State and Regional Greenhouse Gas Emission Reduction Goals

State	GHG Reduction Goal	Western Climate Initiative member (15% below 2005 levels by 2020)	Regional Greenhouse Gas Initiative member (Cap at current levels 2009-2015, reduce this by 10% by 2019)
Arizona	2000 levels by 2020 50% below 2000 levels by 2040	yes	
California	2000 levels by 2010 1990 levels by 2020 80% below 1990 levels by 2050	yes	
Connecticut	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 2001 levels in the long term		yes
Delaware			yes
Florida	2000 levels by 2017 1990 levels by 2025 80% below 1990 levels by 2050		
Hawaii	1990 levels by 2020		
Illinois	1990 levels by 2020 60% below 1990 levels by 2050		
Maine	1990 levels by 2010 10% below 1990 levels by 2020 75-80% below 2003 levels in the long term		yes
Maryland			yes
Massachusetts	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 1990 levels in the long term		yes
Minnesota	15% by 2015, 30% by 2025 80% by 2050		
New Hampshire	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 2001 levels in the long term		yes
New Jersey	1990 levels by 2020 80% below 2006 levels by 2050		yes
New Mexico	2000 levels by 2012 10% below 2000 levels by 2020 75% below 2000 levels by 2050	yes	
New York	5% below 1990 levels by 2010 10% below 1990 levels by 2020		yes
Oregon	Stabilize by 2010 10% below 1990 levels by 2020 75% below 1990 levels by 2050	yes	
Rhode Island	1990 levels by 2010 10% below 1990 levels by 2020 75-80% below 2001 levels in the long term		yes
Utah		yes	
Vermont	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 2001 levels in the long term		yes
Washington	1990 levels by 2020 25% below 1990 levels by 2035 50% below 1990 levels by 2050	yes	

States are also moving aggressively to save energy and reduce their power consumption through energy efficiency and demand side measures. For example, the State of New York has adopted and is now starting to implement a “15 by 15” program through which it intends to reduce energy consumption by 15 percent by 2015.[36] The State of New Jersey has set a goal of reducing energy consumption by 20 percent by 2020.[37]

In addition, regional efforts to reduce greenhouse gas emissions have been undertaken by states in the Northeastern, upper Midwest and Western areas of the nation. Ten Northeastern and Mid-Atlantic States (CT, DE, MD, ME, MA, NH, NJ, NY, RI and VT) are working to create a regional greenhouse gas cap and trade program. The Regional Greenhouse Gas Initiative (RGGI) is a multi-year cooperative effort to design a regional cap and trade program initially covering CO_2 emissions from power plants in the region.

The RGGI states agreed to the following provisions in 2005 and are working to implement this program[38]:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes. Maine, Massachusetts, New York, Rhode Island, and Vermont have all decided to auction all, or nearly all of their allowances.
- Certain offset provisions that increase flexibility to moderate price impacts.
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.[39]

Several states are planning an initial allowance auction for June 2008, in advance of the beginning of the entire RGGI carbon cap program in January 2009.

Subsequently, in February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington announced the formation of the Western Regional Climate Action Initiative to implement a join strategy to reduce greenhouse gas emissions. The initiative is to include (1) developing a regional target for reducing greenhouse gases, (2) developing a market-based program such as a cap-and-trade system and, (3) participating in a multi-state greenhouse gas registry.[40]

In November 2007, the Governors of six Midwestern states, including Minnesota, Illinois, Iowa, Kansas, Michigan and Wisconsin, and the Premier of Manitoba signed the Midwestern Greenhouse Gas Accord. This agreement committed the states to establishing greenhouse gas emissions targets and timetables, to developing a market based and multi-sector cap-and-trade mechanism to achieve those reduction targets, to developing a regional registry and tracking mechanism, and to developing and implementing additional steps as needed to achieve the reduction targets.[41] The Governors of Indiana, Ohio and South Dakota also signed the agreement as observers to participate in the formation of a regional cap-and-trade system.

At the same time, nine states working together through the Midwest Governors Association have adopted the goal of meeting at least 2 percent of regional annual retail sales of electricity through energy efficiency improvements by 2015, with additional savings in subsequent years, and adopted regional renewable energy goals of 10 percent by 2015, 20 percent by 2020, 25 percent by 2025, and 30 percent by 2030.[42] These policies will affect how much new capacity will be needed and what capacity will be the most economic to add.

Uncertainties Related to Carbon Capture and Sequestration

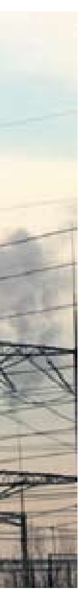
The coal and electric industries are relying heavily on the prospects for capturing and permanently sequestering (CCS) CO_2 emissions as the "silver bullet" to support their claims that new coal-fired power plants can be added while overall CO_2 emissions are reduced. However, there are significant uncertainties regarding the technical and commercial viability of the post-combustion CCS technologies that would be used to capture and sequester the CO_2 emitted by pulverized coal plants. There are promising technologies but these are untested at actual plant-scale sizes and it will be years, if not decades, before they are shown to be technically and commercially viable, if, indeed, they ever are.

A. The Technical Viability of Post-Combustion Carbon Capture is Unproven

Although many are confident that CO_2 can be captured in the pre-combustion CCS technologies used in IGCC facilities, there currently is no commercially viable technology for carbon capture and sequestration from utility scale pulverized coal plants. Carbon capture technologies currently do exist to use CO_2 from flue gases for food/beverage applications and chemicals production. But these would require scaling-up to 20 to 100 times that of current unit sizes for deployment in large-scale powers plants of 500 MW to 1,000 MW.

Currently, there is no commercially viable technology for carbon capture and sequestration from utility scale pulverized coal plants.

The following quote from Entergy presents the generally accepted view in the electric industry in the fall of 2007 regarding the unsettled status of the post-combustion CCS technology that would be used for pulverized coal facilities:



> To date, carbon capture and sequestration has not been demonstrated commercially on any power plant in the United States. Even today, pilot scale projects are only now being developed in the United States. The Company does not believe that this technology is commercially and reliably viable on a utility scale at the current level of technology development. Significant research and development in the performance, cost, and reliability of carbon capture technology remains to be completed. In addition, further research is also required on underground sequestration of carbon, including costs, permitting, and technological advancement such as appropriate geological formations and appropriateness for long term storage of carbon dioxide and the transportation of CO_2 gas.[43]

B. It will be Years, and it may be Decades, Before Post-Combustion Carbon Capture may be Shown to be Technically and Commercially Viable

As noted by Entergy, pilot scale projects are just being started to test and analyze post-combustion carbon capture technologies. The head of AEP has said that he believes that the viability of post-combustion CCS will not be proven until 2015.[44] However, even this might be overly optimistic. The Edison Electric Institute has reported to Congress that "the commercial availability of post-combustion capture technology—a key part of CCS—is still 10 to 15 years away."[45]

Indeed, the 2007 *Future of Coal* study from the Massachusetts Institute of Technology warned that:

> Many years of development and demonstration will be required to prepare for its successful, large scale adoption in the U.S. and elsewhere. A rushed attempt at CCS [carbon capture and sequestration] implementation in the face of urgent climate concerns could lead to excess cost and heightened local environmental concerns, potentially lead to long delays in implementation of this important option.[46]

C. Current Estimates Suggest that Post-Combustion Carbon Capture is Likely to be Very Expensive

It is expected that the addition of carbon capture and sequestration technology will have several adverse impacts on pulverized coal facilities. First, the technology is likely to be very expensive to add. Second, the operation of the technology is likely to result in performance penalties due to reduced plant efficiency and the addition of the additional on-site auxiliary (also known as "parasitic") loads needed to operate the new CCS equipment. This will lower the plant's net output. Together these impacts will greatly increase the cost of generating electricity.

For example, a 2007 study by the National Energy Technology Laboratory of the U.S. Department of Energy ("NETL") has shown that the addition of CO_2 capture technology would increase a supercritical coal plant's heat rate from 8,721 Btu/KWh to 12,534 Btu/KWh while increasing the plant's auxiliary loads from 30 MW to 117 MW.[47] Thus, a 580 MW gross supercritical coal plant that would generate 550 MW of power without CO_2 capture technology would produce only 463 MW with CO_2 capture. To generate the same 550 MW net output, the gross output of the plant with CO_2 capture would have to be 663 MW instead of the 580 MW gross output it would need without CO_2 capture.

Given the very preliminary state of the testing of post-combustion carbon capturing technologies, it is not surprising that there is great uncertainty regarding the costs of actually capturing and sequestering CO_2 from pulverized coal facilities. However, a number of independent sources agree, as illustrated in Table 5, that adding and operating CCS equipment will raise the cost of generating electricity at new coal-fired power plants by perhaps as much as 60 percent to 80 percent.

Table 5: Projected Increase in the Cost of Generating Power Due to Carbon Capture and Sequestration

Source	Projected Increase in Cost of Electricity from Addition of CCS
Duke Energy Indiana[48]	68%
MIT Future of Coal Report[49]	61%
Edison Electric Institute[50]	75%
National Energy Technology Laboratory[51]	81%

In comparison, the National Energy Technology Laboratory has estimated that the addition and operation of CO_2 capture equipment will increase the cost of electricity from a natural gas combined cycle plant by 43 percent.[52]
Generating power at a new pulverized coal plant owned by an investor owned company has been estimated to have a levelized cost of approximately $75/MWh.[53] Based on the results of the studies listed in Table 5, producing power at this same plant with CO_2 capture and sequestration technology could cost between $121/MWh and $136/MWh.[54]

A number of these same independent studies also estimated the impact of CCS as a price per ton of CO_2 avoided. For example, the 2007 NETL study calculated that the cost of carbon capture would be $68/ton of CO_2 avoided, in 2007 dollars, for pulverized coal plants.[55] However, this cost was only for CO_2 capture. Transporting and sequestering the captured CO_2 would add to this cost.

The 2007 *Future of Coal Study* from the Massachusetts Institute of Technology estimated that the cost of carbon capture and sequestration would be about $28/ton although it also acknowledged that there was uncertainty in that figure.[56] The tables in that study also indicated significantly higher costs for carbon capture for new supercritical pulverized coal facilities of approximately $37/ton.[57] However, this cost is only for the cost of capture. As noted above, the transportation and sequestration of the captured CO_2 would increase this cost.[58]

Moreover, these costs were for new plants that were designed and built to include carbon capture technology at the outset. The MIT *Future of Coal Study* concluded that it would be much more expensive to retrofit carbon capture technology onto existing coal-fired power plants.[59] That means that the cost of retrofitting carbon capture technology onto plants that would already be built and in operation at the time that the technology becomes proven and commercially viable could be significantly higher than the $40/ton figure shown in the MIT Study for new coal plants.

Similarly, in a recent proceeding at the West Virginia Public Service Commission, Appalachian Power Company has estimated the costs of electricity from a number of coal-fired technologies with and without carbon capture and sequestration.[60] Appalachian Power estimates that the cost of just capturing the CO_2 emissions from a new pulverized coal plant would be approximately $43-$46/MWh on a levelized basis.

Some in the industry have claimed that new technologies now being studied (that is, aqueous ammonia and chilled ammonia) may hold the promise of lowering carbon capture and sequestration costs to perhaps as low as $20/ton of CO_2 avoided. However, these technologies have only been evaluated in very small scale tests and the associated results are very preliminary. Also, the estimated $20/ton cost appears to be only based on an unsupported vendor claim. Finally, an early 2007 draft NETL study identified major concerns with these technologies. Unfortunately, the Department of Energy subsequently decided to classify this draft study.

It is important to keep in mind that even if or when the technology for CO_2 capture matures, there will always be significant regional variations in the cost of the transportation and storage of the captured CO_2 due to the proximity and quality of storage sites.

D. The Availability of Cooling Water for Carbon Capture Poses another Risk for New Coal-Fired Power Plants

The National Energy Technology Laboratory has estimated that the use of water at coal-fired power plants with Carbon Capture and Sequestration will be 2.16 times that of plants without.

The National Energy Technology Laboratory has estimated that the use of water at coal-fired power plants with CCS will be 2.16 times that of plants without CCS (21.6 versus 10.0 gallons per minute per MWnet).[61] This increase in water usage is due to the cooling water requirements of the CO_2 capture process.[62] The availability of this additional water is another uncertainty associated with new coal-fired power plants especially for those plants located in arid areas and/or during peak summer conditions or prolonged drought conditions.

E. Company Claims that New Coal-Fired Power Plants will be "Carbon Capture Ready" Must be Scrutinized Carefully

Companies seeking to build new coal-fired power plants are increasingly claiming that their facilities will be "carbon-capture ready." Unfortunately, these companies do not typically identify any carbon capture equipment that is being included in the design and construction of the plants. At most, the companies reveal that they have merely allowed extra room to add carbon capture equipment when the technology becomes commercially viable.

Indeed, given the very early stage of development and testing of power plant scale carbon capture technologies, it should not be expected that any new pulverized coal plant being proposed today actually can be ready to capture carbon in the foreseeable future, on anything but a test or pilot basis. As noted earlier, the addition of CCS equipment is expected to significantly reduce the net power output of a plant. At most, the companies planning to add new pulverized coal facilities in the foreseeable future can overbuild their new plants (that is build them larger in terms of net MWs than they would otherwise need to be) to allow for the additional parasitic loads that will be created by carbon capture equipment. But that would make the plants even more expensive and less economic than other supply-side and demand-side options. Moreover, as noted above, it is expected the retrofitting carbon capture technology to existing power plants will be even more expensive that including such equipment as part of the plant's original design. Consequently, the more reasonable alternative is to wait until post-combustion carbon capture and sequestration has been shown to be technically and commercially viable before designing and building new pulverized coal facilities.

Given the very early stage of development and testing of power plant scale carbon capture technologies, it should not be expected that any new pulverized coal plant being proposed today actually can be ready to capture carbon in the foreseeable future.

Construction Cost Increases and Schedule Delays

A. Power Plant Construction Costs are Skyrocketing due to Worldwide Competition for Design and Construction Resources

The costs of building power plants have soared in recent years as a result of the worldwide demand for power plant design and construction resources and commodities. There is no reason to expect that plant costs will not continue to rise during the years when the detailed engineering, procurement and construction of power plants now being proposed will be underway. This is especially true if engineering and procurement for the projects are at a conceptual or early stage.

For example, Duke Energy Carolinas' originally estimated the cost for the two unit coal-fired Cliffside Project at approximately $2 billion. In the fall of 2006, Duke announced that the cost of the project had increased by approximately 47 percent ($1 billion). After the project had been downsized because the North Carolina Utilities Commission refused to granted a permit for two units, Duke announced that the cost of that single unit would be about $1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building that single unit had increased by about another 20 percent. As a result, the estimated cost of the one unit that Duke is building at Cliffside is now $1.8 billion excluding financing costs. Thus, the single Cliffside unit is now expected to cost almost as much as Duke originally estimated for a two unit plant.

In testimony filed at the North Carolina Utilities Commission on November 29, 2006, Duke Energy Carolinas emphasized that the competition for resources had had a significant impact on the costs of building new power plants. This testimony was presented to explain the approximate 47 percent ($1 billion) increase in the estimated cost of Duke Energy Carolinas' proposed coal-fired Cliffside Project that the Company announced in October 2006.

Duke Energy Carolinas explained to the North Carolina Commission that:

> The costs of new power plants have escalated very rapidly. This effect appears to be broad based affecting many types of power plants to some degree. One key steel price index has doubled over the last twelve months alone. This reflects global trends as steel is traded internationally and there is international competition among power plant suppliers. Higher steel and other input prices broadly affects power plant capital costs. A key driving force is a very large boom in U.S. demand for coal power plants which in turn has resulted from unexpectedly strong U.S. electricity demand growth and high natural gas prices. Most integrated U.S. utilities have decided to pursue coal power plants as a key component of their capacity expansion plan. In addition, many foreign companies are also expected to add large amounts of new coal power plant capacity. This global boom is straining supply. Since coal power plant equipment suppliers and bidders also supply other types of plants, there

is a spill over effect to other types of electric generating plants such as combined cycle plants.[63]

Duke further noted that the actual coal power plant capital costs as reported by plants already under construction exceed government estimates of capital costs by "a wide margin (i.e., 35 to 40 percent). Additionally, current announced power plants appear to face another increase in costs (i.e., approximately 40 percent addition."[64] Thus, according to Duke, new coal-fired power plant capital costs had increased approximately 90 to 100 percent since 2002.

A large number of projects have announced significant construction cost increases over the past few years. For example, the cost of Westar's proposed coal-fired plant in Kansas, originally estimated at $1 billion, increased by 20 percent to 40 percent, over just 18 months.

Similarly, the projected costs for the nominal 1,600-megawatt coal-fired White Pine Energy Station in Nevada has more than tripled during just the past two years. In 2004, the company estimated that capital investment in the facility would range from $600 million to over $1 billion, depending on the final size of the project. By April 2006, however, projected capital investment had climbed from a range of $1 billion to over $2 billion. That figure increased even further by August 2007, ranging from over $1 billion to more than $3 billion.

The estimated cost of the now-cancelled Taylor Energy Center in Florida increased by 25 percent, $400 million, in just 17 months between November 2005 and March 2007. The estimated cost of the Big Stone II coal-fired power plant project in South Dakota has increased by about 60 percent since the project was first announced. Finally, the estimated cost of the Little Gypsy Repowering Project (gas to coal) increased by 55 percent between announcement of the project in April 2007 and the filing of a request for a license to build in July 2007.

The worldwide competition is driven mainly by huge demands for power plants in China and India, by a rapidly increasing demand for power plants and power plant pollution control modifications in the United States required to meet SO_2 and NO_x emissions standards, and by the competition for resources from the petroleum refining industry. The demand for labor and resource to rebuild the Gulf Coast area after Hurricanes Katrina and Rita hit in 2005 also has contributed to rising costs for construction labor and materials. The expected construction of new nuclear power plants also is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

Worldwide competition for power plant design and construction resources as the driving force for the skyrocketing construction costs.

A number of financial and utility industry sponsored studies have identified this worldwide competition for power plant design and construction resources as the driving force for the skyrocketing construction costs.

For example, a June 2007 report by Standard & Poor's, *Increasing Construction Costs Could Hamper U.S. Utilities' Plan to Build New Power Generation*, has noted that:

> As a result of declining reserve margins in some U.S. regions … brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50 percent in the past three years, with more than 70 percent of this increase resulting from engineering, procurement and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT). In a separate yet key point, as capital costs rise, energy efficiency and demand side management already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity.[65]

More recently, the president of the Siemens Power Generation Group told the New York Times that "There's real sticker shock out there."[66] He also estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 to 30 percent.

In its Application to the Ohio Power Siting Board for a permit to build a 960 MW subcritical coal-fired power plant, AMP-Ohio noted that the price increases currently being experienced in the expected construction costs of coal based electric generation "are staggering."[67] AMP-Ohio also noted that "Price increases of 10 percent in a single six month period are being reported. Using this data and similar data on other projects as an estimate, a one month delay in a $2 billion project is over $33 million."[68]

A September 2007 report on Rising Utility Construction Costs prepared by the Brattle Group for the EDISON Foundation of the Edison Electric Institute similarly concluded that:

> Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.[69]

The report further found that:

- Dramatically increased raw materials prices (e.g., steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.

- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or project supply. There also is a growing backlog of project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects…. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more – substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants – and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives to reduce the future rate impacts on consumers.[70]

Table 6 was presented by the Appalachian Power Company in its testimony to the West Virginia Public Service Commission seeking to build a new IGCC coal power plant. The figures in this table show the tremendous escalation in commodities' prices that was experienced by the construction industry between 2003 and early 2007:

Table 6: Average Annual Escalation in Power Plant Commodities

Commodity/ Construction Material	Average Annual Escalation from ~1986-2003	Average Annual Escalation Dec. 2003-April 2007	Escalation during Dec. 2003 – April 2007 As Ratio of Recent Historic Average
Nickel	3.80%	60.30%	15.9x
Copper	3.30%	69.20%	21x
Cement	2.70%	11.60%	4.3x
Iron & Steel	1.20%	19.60%	16.3x
Heavy Construction	2.20%	10.50%	4.8x

More recent information suggests that there has been some moderation in commodity price escalation during 2007. However, it is uncertain whether this is a short-term blip or a long-term trend. There is no way to know at this time and that is a substantial uncertainty concerning the ultimate cost of new coal-fired power plants. Based on the continuing domestic and worldwide demand for the resources need to design and build new power plants, we believe it is reasonable to expect that prices will again increase at very significant rates but we will have to see. For example, it has been discussed that India is on the threshold of a rapid expansion in the near future that will put additional pressure on the availability of raw materials, shop fabrication space and available work force for engineering, site management staff and field labor and supervision.[71]

Unfortunately, the estimated construction costs for new coal-fired power plants are not publicly reported on a consistent basis. Some estimates include allowances for contingencies, escalation and/or financing costs. Some do not. Some estimates are in undeterminable constant year dollars. Some are in as-spent dollars. Given these circumstances, it is very difficult to determine what is a reasonable cost estimate to assume for new coal plants in resource planning studies.

Nevertheless, the most recent cost estimates for those plants that are not yet under construction appear to be on the order of \$2500/kW without financing costs, in nominal, as-spent dollars. However, given recent trends, it is reasonable to expect that the actual costs of these plants will not be even higher by the time that construction is completed.

Synapse has been recommending that for companies considering building new coal plants, planning studies should include sensitivity analyses that examine the relative economics of proposed projects that assume that capital costs are substantially higher than now estimated. For example, based on recent trends, it is reasonable to assume in such sensitivity studies that plant capital costs will be 20 percent and 40 percent higher than currently estimated costs. Analyzing such additional cost increases is justified, indeed necessary, in light of recent industry experience and the expectation that worldwide demand will continue to be a driving force for rising prices for the foreseeable future. For projects that are not yet under construction, this would mean evaluating the projects using a range of \$2500/kW to \$3500/kW, excluding financing costs, in nominal, as-spent dollars.

B. Risks that were Once Borne by Contractors are being Shifted to Plant Owners

In the past, the major Engineering, Procurement and Construction (EPC) contractors were willing to enter into fixed price contracts for new power plants. As a result, the contractors bore the risks that actual materials, equipment and component prices would be higher than estimated.

Recent experience at a number of power plant construction projects shows that the major EPC contractors are no longer willing to enter into fixed price contracts. The recent testimony of an Appalachian Power Company witness reflects an increasingly common experience:

> Company witness Renchek discusses in his testimony the rapid escalation of key commodity prices in the EPC industry. In such a situation, no contractor is willing to assume this risk for a multi-year project. Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher.[72]

An engineering assessment for the City of Cleveland involving a different power plant project similarly concluded that:

> [Burns & Roe Enterprises, Inc.] agrees that the fixed price turnkey EPC contract is a reasonable approach to executing the project. However, the viability of obtaining a contract of this type is not certain. The high cost of the EPC contract, in excess of \$2 billion, significantly reduces the number of potential contractors even when teaming of engineers, constructors and equipment suppliers is taken into account. Recent experience

> on large U.S. coal projects indicates that the major EPC Contractors are not willing to fix price the entire project cost. This is the result of volatile costs for materials (alloy pipe, steel, copper, concrete) as well as a very tight construction labor market. When asked to fix the price, several EPC Contractors have commented that they are willing to do so, but the amount of money to be added to cover potential risks of a cost overrun would make the project uneconomical.73

As a result, construction project contracts shift the risks of higher commodities, equipment and/or labor costs to plant owners and investors.

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More Stringent Regulation of Non-Greenhouse Gas Emissions

Further restrictions on NO_x, SO_2, and Mercury emissions, affecting coal-fired power plants, are either pending or proposed. The EPA is moving forward with plans to implement the deepest cuts of NO_x and SO_2 emissions from electric generation in more than a decade via the Clean Air Interstate Rule (CAIR).[74] Signed in March 2005 and projected to begin to take effect in 2009 for NO_x and 2010 for SO_2, this rule proposes a cap and trade mechanism to reduce emissions of NO_x and SO_2 by plants in eastern states to approximately 70 percent and 60 percent below 2003 levels once fully implemented, respectively.[75,76] As power plants were responsible for 22 percent of NO_x emissions and 69 percent of SO_2 emissions as of 2004, they will be responsible for helping to achieve these reductions.[77]

The EPA is also moving forward with a companion piece to CAIR, called the Clean Air Mercury Rule (CAMR), which was also signed in March 2005. CAIR is projected to achieve some mercury reductions in addition to NO_x and SO_2 reductions. However, CAMR was developed to realize further reductions. Projected to take effect in 2010, this rule specifically targets coal-fired electric plants with goals of attaining 70 percent reductions from 2003 levels once fully implemented.[78,79] This rule has generated much opposition by up to 20 individual states which are proposing larger cuts and many of them more rapidly than this rule.[80]

A second action related to CAIR known as the Clean Air Visibility Rule (CAVR) was signed in June 2005.[81] CAVR requires best available retrofit technology (BART) for older power plants emitting air pollutants that reduce visibility in specially protected areas. While required reductions are not as stringent as CAIR, CAVR covers mid-western and western states that are not addressed by CAIR. These pollutants include particulate matter (PM2.5) and compounds that contribute to particulate matter formation such as NO_x and SO_2.[82]

Finally, revisions to the 1997 primary and secondary ground-level ozone standards proposed by EPA are pending. Proposed in June 2007 as a response to new scientific evidence about the effects of ozone on people and public welfare, these revisions require NOx emission reductions to new levels by attainment dates between 2013 and 2030, depending on the area.[83]

Further emissions reductions on NO_x, SO_2 and Mercury are well underway and will have an impact on coal plant costs in the next few years. These reductions will increase the cost of compliance of coal power plants, reducing profit margins of existing plants and eroding the benefits of building new plants.

Emissions reductions on NOx, SO_2 and Mercury are well underway and will increase the cost of compliance of coal power plants, reducing profit margins of existing plants and eroding the benefits of building new plants.


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Uncertainties regarding the Recovery of Plant Construction and Operating Costs

Investors in regulated utilities face the risk that regulatory commissions will not approve the full recovery of the higher capital and operating costs that would result from the factors we have discussed. Investors in unregulated or merchant companies face the risk that these companies will not be able to fully recover these increased costs through the prices they receive for power sold in the deregulated markets.

As noted earlier, during the 1970s, 1980s and 1990s state regulatory commissions disallowed billions of dollars of nuclear power plant construction costs that had resulted from project mismanagement. A number of companies have learned from this experience and are requesting pre-approval determinations that plant expenditures will be found to be prudent. However, even though they may be issued certificates to build new coal-fired power plants, regulatory commissions are reserving the power to disallow imprudently incurred construction and/or operating costs.

For example, in its November 21, 2007 Order granting SWEPCO a Certificate of Environmental Compatibility and Public Need to build the proposed 600 MW Turk pulverized coal facility, the Arkansas Public Service Commission specifically conditioned the granting of the certificate "upon and subject to the jurisdiction of this Commission to conduct future prudence reviews and to make any appropriate prudence adjustments regarding any cost overruns associated with the construction and operation of the Turk plant beyond the costs as estimated in this proceeding by SWEPCO or AEP."[84]

Even though they may issue certificates to build new coal-fired power plants, regulatory commissions are reserving the power to disallow imprudently incurred construction and/or operating costs.

Similarly, even though it has certified Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 power plant as a coal-fired facility, the Louisiana Public Service Commission specifically noted that "Notwithstanding certification, [Entergy Louisiana] retains an affirmative obligation to plan, construct, and operate the Repowering Project over its useful life in a manner consistent with providing reliable service at lowest reasonable cost. This includes the prudent management of the … construction contract."[85]

Finally, the Minnesota Department of Commerce has recently recommended that if the Minnesota Public Utilities Commission approves the proposed Big Stone II coal-fired power plant, it should (1) limit Otter Tail Power's recovery of future CO_2 costs to the $9/ton figure that the Company has used in its recent economic modeling analyses justifying the project and (2) shift a portion of the risk associated with higher capital costs to shareholders.[86] The Department of Commerce proposed that the Commission do so (a) by limiting construction cost recovery to the current cost estimate or (b) by limiting construction cost recovery to the current estimate plus ten percent to allow for inflation and normal construction costs fluctuations. In the alternative, the Department of Commerce recommended that the Minnesota Commission provide no guarantee of cost recovery to Otter Tail Power at this time and instead defer the entire issue of just and reasonable costs to the Company's first rate case after the plant becomes used and useful to ratepayers. In such a proceeding, Otter Tail Power would have the burden of showing that the project construction costs it seeks to recover in rates are justified.

Conclusion

Historically, investments in coal-fired power plants were relatively stable and safe investments. But that is no longer true. Now investments in companies that are currently building or that are planning to build new coal-fired plants carry far more risk, in particular, because of the likely regulation of greenhouse gas emissions and rising construction costs. As a result, investors in both regulated and merchant companies cannot be assured that they will recover and earn reasonable returns on their investments.

Photo credit: morguefile

Endnotes

1 For example, see http://www.nreca.org/aboutus/cooperativedifference/gettingrailroaded.htm.

2 See http://www.eia.doe.gov/oiaf/aeo/otheranalysis/cti.html.

3 Docket No. 05-035-47 Before the Public Service Commission of Utah http://www.psc.**utah**.gov/elec/05docs/0503547/55486NoticeWithdrawal.doc.

4 Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

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6 Id.

7 See http://www.marketwatch.com/news/story/txu-reversal-coal-plant-emissions-shocks/story.aspx?guid=%7BCBF10ED6%2DCA64%2D4533%2DA7E8%2DCC903D8E243B%7D.

8 http://www.tampaelectric.com/news/article/index.cfm?article=430.

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10 Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-34.

11 Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07__, December 14, 2007, at page 4-1.

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13 *Petition for Approval, Minnesota Power's 2008 Resource Plan*, Minnesota Public Utilities Commission Docket No. E015/RP-07-1357, dated October 31, 2007, at page 5.

14 Id, at page 6.

15 U.S. Securities and Exchange Commission Form 10-Q, Third Quarter of 2007, Idaho Power Company, at pages 49-50.

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http://www.avistautilities.com/inside/transmission/irp/gas/Pages/default.aspx

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18 Notice of Decision, North Carolina Utilities Commission Docket No. E-7, Sub 790, Feb. 28, 2007

19 Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

20 Order in Docket No. E-6472/M-05-1993, dated August 30, 2007, at pages 16-19.

21 http://www.washingtonpost.com/wp-dyn/content/article/2007/10/18/AR2007101802452.html.

22 More detailed summaries of the bills that have been introduced in the U.S. Senate in the 110th Congress are presented in Appendix A to this Report.

23 *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning* Synapse Energy Economics, May 2006

24 *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* Energy Information Administration, July 2007, Supplement to the Energy and Markets Impacts of S. 280, Energy Information Administration, October 2007, and *EPA Analysis of the Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007.

25 Thirty different scenarios were modeled in the April 2007 MIT Assessment. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990 levels by 2050, or stabilize CO_2 emissions at 2008 levels), whether banking of allowances would be allowed, whether international trading of allowances would be allowed, whether only developed countries or the U.S. would pursue greenhouse gas reductions, whether there would be safety valve prices adopted as part of greenhouse gas regulations, and other factors.

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28 Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-30.

29 Prefiled Supplemental Rebuttal Testimony of Thomas Hewson, Applicants' Exhibit 128, Minnesota Public Utilities Commission Dkt No. CN-5-619, dated January 16, 2008, at page 4, lines 7-9.

30 Id.

31 Regional Greenhouse Gas Initiative Memorandum of Understanding, December 2005.

32 Deutsche Bank Research; EU emission trading-- Allocation battles intensifying; Deutsche Bank, March 6, 2007.

33 *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page (xiv).

34 This would be approximately 15 percent of the roughly 1 ton per MWh emissions that can be expected from a new coal-fired power plant.

35 California Senate Bill 1368, "An act to add Chapter 3 (commencing with Section 8340) to Division 4.1 of the Public Utilities Code, relating to electricity;" Perata, Chapter 598, Statutes of 2006.

36 Remarks by Governor Eliot Spitzer. "15 by 15": A Clean Energy Strategy for New York. 19 Apr 2007. Found at: http://www.state.ny.us/governor/keydocs/0419071_speech.html.

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38 D. Kahn, "Northeast States Prepare for Inaugural Carbon Auction," Greenwire, January 22, 2008.

39 The RGGI Memorandum of Understanding ("MOU") states "Each state will maintain and, where feasible, expand energy policies to decrease the use of less efficient or relatively higher polluting generation while maintaining economic growth. These may include such measures as: end-use efficiency programs, demand response programs, distributed generation policies, electricity rate designs, appliance efficiency standards and building codes. Also, each state will maintain and, where feasible, expand programs that encourage development of non-carbon emitting electric generation and related technologies." RGGI MOU, Section 7, December 20, 2005.

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45 Letter to Hon. Edward J. Markey, Chairman, Select Committee on Energy Independence and Global Warming, from Thomas R. Kuhn, Edison Electric Institute, September 21, 2007, at page 4.

46 *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page 15.

47 *Cost and Performance Baseline for Fossil Energy Plants*, *Revised August 2007,* DOE/NETL – 2007/1281, at page 4.

48 Testimony of James E. Rogers in Indiana Utility Regulatory Commission Cause No. 43114, Joint Petitioners' Exhibit No. 1, at page 13, lines 6-11.

49 *The Future of Coal*, *Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page 19.

50 Letter to Hon. Edward J. Markey, Chairman, Select Committee on Energy Independence and Global Warming, from Thomas R. Kuhn, Edison Electric Institute, September 21, 2007, at page 4.

51 *Cost and Performance Baseline for Fossil Energy Plants*, *Revised August 2007,* DOE/NETL – 2007/1281, at page 17.

52 Id.

53 Big Stone II Applicants' Exhibit 121 in Minnesota PUC Docket No. CN-05-619, at page 11.

54 These costs represent the $75/MWh cost times 1.61 and 1.81 which represent the upper and lower ends of the range of projected cost increases due to CCS presented in Table 5.

55 *Cost and Performance Baseline for Fossil Energy Plants*, *Revised August 2007,* DOE/NETL – 2007/1281, at page 17.

56 *The Future of Coal*, *Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page xi.

57 The cost of carbon capture at a supercritical coal-fired power plant was presented in the MIT Future of Coal Study as $41/tonne. This translates into a cost of approximately $37/ton.

58 Id, at page 19.

59 Id, at pages 28-29.

60 Appalachian Power Company witness Renchek's Exhibit MWR-4, revised, in West Virginia Case No. 06-0033-E-CN.

61 *Cost and Performance Baseline for Fossil Energy Plants*, *Revised August 2007,* DOE/NETL – 2007/1281, at page 8.

62 *Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements, 2007 Update,* DOE/NETL—400/2007/1304, page 27, available at http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/2007WaterNeedsAnalysis-UPDATE-Final_10-10-07b.pdf

63 Direct Testimony of Judah Rose for Duke Energy Carolinas, North Carolina Utilities Commission Docket No. E-7, SUB 790, at page 4, lines 2-14. Mr. Rose's testimony is available on the North Carolina Utilities Commission website.

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New investments in companies that are currently building or that are planning to build new coal-fired plants carry far more risk, in particular, because of the likely regulation of greenhouse gas emissions and rising construction costs. As a result, investors in both regulated and merchant companies cannot be assured that they will recover and earn reasonable returns on their investments.