

Synapse
Energy Economics, Inc.

The Financial Risks to Old Dominion Electric Cooperative's Consumer- Members of Building and Operating the Proposed Cypress Creek Power Station

by

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Executive Summary

Conclusion: Synapse Energy Economics, Inc. (“Synapse”) has completed a preliminary assessment of Old Dominion Electric Cooperative’s (“ODEC”) proposed Cypress Creek Power Station. The source materials for this assessment have included publicly available documents.

We have concluded that there are significant risks to ODEC’s consumer-members associated with the construction and operation of the proposed Cypress Creek facility. The sources of risk include:

- Uncertainty as to coal plant construction costs and schedules.
- Uncertainty over the availability of financing in the capital markets, and the magnitude of financing costs.
- Uncertainty as to the greenhouse gas emissions reductions that ultimately will be required as a result of federal, regional or state action.
- Uncertainty as to the cost of compliance with likely future regulations, including the future carbon dioxide emissions allowance prices.
- Uncertainty as to the technical viability of post-combustion carbon capture and sequestration as a retrofit for pulverized coal plants like the proposed Cypress Creek Power Station.
- Uncertainty as to the costs and economic viability of post-combustion carbon capture and sequestration for pulverized coal plants, if it does prove technically viable.
- Uncertainty regarding whether currently projected on-system and off-system loads will materialize.
- Uncertainty as to whether the federal government will adopt a national Renewable Portfolio Standard.
- Uncertainty as to future coal prices and whether there will be supply disruptions that will affect plant performance and fuel prices.
- Uncertainty about whether the regulations for current criteria pollutants (such as NO_x, SO₂ and mercury) will be made more stringent.

Instead of a plan that maximizes ODEC’s near-term commitment to an expensive capital-intensive coal investment that could cost in excess of \$6 billion, it is better to adopt a flexible resource plan in today’s uncertain times that allows for:

1. The postponement of decisions concerning large capital expenditures for new coal-fired power plants.
2. The plan to be modified as circumstances change

In particular, we have found the following:

- Finding 1. ODEC is committing to a very expensive and capital-intensive generation expansion plan at a time of significant economic and financial uncertainty.
- Finding 2. Uncertainty over construction costs and the costs of complying with future federal carbon dioxide emission reduction requirements have, in significant part, led to more than 80 coal power plant cancellations, delays and rejections by state regulatory commissions.
- Finding 3. The construction cost of the proposed Cypress Creek Power Station could exceed the \$6 billion figure publicly cited by ODEC.
- Finding 4. A comprehensive system for federal regulation of carbon dioxide (CO₂) and other greenhouse gas emissions is imminent. It is generally expected that this federal regulation will require steep reductions in national greenhouse gas emissions. Since coal is the most carbon intensive fuel, greenhouse gas restrictions are likely to be a significant factor in the economics of coal-fired power plants.
- Finding 5. ODEC has said that the 1,500 MW Cypress Creek Power Station will emit approximately 14.6 million tons of CO₂ each year. There is currently no commercially viable technology for capturing CO₂ emissions from a pulverized coal plant like Cypress Creek.
- Finding 6. ODEC's consumer-members will face significant costs associated with the decision to lock in the carbon emissions from the proposed Cypress Creek Power Station for decades.
- Finding 7. ODEC has not presented evidence that building and operating the proposed Cypress Creek Power Station is the lowest cost option for ODEC's consumer-members.
- Finding 8. ODEC's consumer-members will be committed to paying all of the costs associated with the proposed Cypress Creek Power Station for at least 45 years.
- Finding 9. ODEC has not demonstrated a need for all of the 1,500 MW from the proposed Cypress Creek Power Station until 2030 or later. It also has not demonstrated a need for all of the 750 MW from one of the proposed units at Cypress Creek until approximately 2020.
- Finding 10. Publicly available information suggests that there are less expensive alternatives to the Cypress Creek Power Station that would reduce environmental impact and avoid the risk of expensive regulatory costs that would be borne by ODEC's consumer-members.

FINDINGS

Finding 1. ODEC is committing to a very expensive and capital-intensive generation expansion plan at a time of significant economic and financial uncertainty.

ODEC is undertaking a construction program that may ultimately cost in excess of \$7 billion over the next decade (that is, \$6 billion for the Cypress Creek Power Station and \$1 billion or more for its share of the new nuclear unit at North Anna). A capital investment program of this magnitude could be expected to strain ODEC's financial resources even in normal times. However, ODEC proposes to begin this investment program in a time of extreme economic and financial crisis, as well as tremendous uncertainty over costs associated with new coal investment. This commitment to significant capital investment arises just when economic conditions heighten the sensitivity of member cooperatives and their consumer-members to rate increases

The current economic recession represents a near term challenge for utilities, and exacerbates risks that ODEC and other electric utilities face. In fact, according to the Wall Street rating agency Standard and Poor's, the "worst economic slump since World War II" will present significant challenges to U.S. electric cooperatives and public power utilities just as "prospects for regulation of greenhouse gas emissions have never been higher and capital needs abound."¹ Standard & Poor's also believes that "the worst of the [economic] downturn is still ahead" and that "the downturn is likely to be relatively prolonged, and recovery should be sluggish."²

The primary recession-related challenges identified by Standard and Poor's include: "declining energy sales, regional capacity surpluses that render some units uncompetitive and limit the ability to make budgeted margins on off-system sales, increasing payment delinquencies and bad debt expense, which could stress liquidity and coverage levels; and political pressure to hold down rates and/or provide increasing levels of support to help plug the budget gaps of municipal governments."³

At the same time that the economic recession strains utilities like ODEC, the financial crisis and ongoing credit crunch create uncertainty as to their ability to raise needed capital and to determine what the costs of borrowing will be for the capital they need in order to undertake proposed projects. Standard & Poor's has warned that "The financial market turmoil poses a challenge for public power utilities in the midst of large-scale capital projects that have no other source of funds, and could face construction delays, and higher borrowing costs whether they obtain short- or long-term financing."⁴

¹ Standard and Pooors' – Public Finance; "Will the Recession Pull the Plug on U.S. Public Power Companies and Electricity Co-ops?" March 4, 2009.

² Standard & Poor's, *U.S. Public Power Outlook: 2009 Could Provide Some Shocks*, January 20, 2009, at page 4.

³ Standard and Pooors' – Public Finance; "Will the Recession Pull the Plug on U.S. Public Power Companies and Electricity Co-ops?" March 4, 2009.

⁴ Standard & Poor's, *U.S. Public Power Outlook: 2009 Could Provide Some Shocks*, January 20, 2009.

Entergy Louisiana is an example of a utility that has suspended construction of a proposed coal plant to allow available capital to be used on other projects:

In addition, the changes in the U.S. and world economies have caused great turmoil in the capital markets. This turmoil has affected both the cost of capital and the timing of its availability....When engaging in a large project such as the [coal-fired Little Gypsy] Repowering Project, which will drive the timing of the need for capital, there could be a constraint in obtaining – at the time it is needed and at rates that are attractive economically – the capital that is needed to fund the Repowering Project as well as [the Company’s] other resource needs. Given the uncertainties in the economics of the Repowering Project, it would seem to be a more prudent use of capital for [Entergy Louisiana] to plan to fund those other projects and retain additional liquidity while delaying the Repowering Project until additional clarity can be gained regarding the Project economics.⁵

What this means is that ODEC may find itself seriously weakened due to the economic recession at the very time it seeks to finance its multi-billion construction program. It also may be forced to pay much higher costs to borrow capital from the market for its proposed investments in Cypress Creek and North Anna.

In fact, there is some evidence that obtaining capital for new coal-fired power plants will be very difficult in the current environment. For example, last fall, the developers of the proposed Highwood Generating Station in Montana were reported to have difficulty obtaining funding for their project.⁶ The developers have since announced that they will build a natural gas-fired plant at the site instead of a coal plant.

Finding 2. Uncertainty over construction costs and the costs of complying with future federal carbon dioxide emission reduction requirements have, in significant part, led to more than 80 coal power plant cancellations, delays and rejections by state regulatory commissions.

ODEC is one of many utilities that have considered investing in new coal-fired power in recent years. Public and investor-owned utilities and state regulatory commissions and officials have recognized the risks associated with new coal plant investments under current circumstances and have chosen to cancel, delay or reject more than 80 proposed coal-fired power plants.

In fact, more than thirty proposed coal-fired plants have been cancelled in just the three years since early 2006. More than forty others have been delayed. Although some proposed plants have been approved, state regulatory Commissions in North Carolina, Florida, Virginia, Oklahoma, Washington State, Oregon, and Wisconsin have rejected proposed power plants. The Secretary of Health and Environment of the State of Kansas also has rejected permits for two 700 MW coal-fired power plants.

Regulators have cited several reasons for cancelling new coal construction. For example, the July 2007 decision of the Florida Public Service Commission denying approval for the 1,960

⁵ Ibid., at pages 6-8.

⁶ “Funding questions linger as power plant breaks ground,” Great Falls Tribune, October 19, 2008.

MW Glades Power Project was based on concern over the uncertainties of plant construction costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.⁷

In April of 2008, the Virginia State Corporation Commission rejected a proposed coal plant citing uncertainties of costs, technology, and unknown federal mandates.⁸ The Commission concluded that "... [Appalachian Power Company] has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in [Appalachian Power Company's] service territory to assume."⁹

The Commission also noted the uncertainties surrounding federal regulation of carbon emissions, and carbon capture and sequestration technology and costs, and observed that the Company was asking for a "blank check."¹⁰ On this basis, the Commission concluded that "We cannot ask Virginia ratepayers to bear the enormous costs – and potentially huge costs – of these uncertainties in the context of the specific Application before us."¹¹

Then, in November 2008, the Public Service Commission of Wisconsin rejected a coal-fired power plant that had been proposed by Wisconsin Power & Light. The Commission decided that the \$1.26 billion project was too costly when weighing it against other alternatives such as natural gas generation and the possibility of purchasing power from existing sources.¹² The Commission also said that "Concerns over construction costs and uncertainty over the costs of complying with future possible carbon dioxide regulations were all contributing factors to the denial."¹³

At the same time, a large number of investor-owned and public power utilities have cancelled or delayed new coal-fired generating facilities. For example:

- 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

⁷ Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

⁸ Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://scc.virginia.gov/newsrel/e_apfrate_08.aspx.

⁹ Id., at page 5.

¹⁰ Id., at page 10.

¹¹ Id., at page 10.

¹² The estimated cost of the proposed coal plant was \$1.26 billion for a 326 MW facility.

¹³ *PSC Rejects Wisconsin Power & Light's Proposed Coal Plant*, issued by the Public Service Commission of Wisconsin on November 11, 2008.

proceed with caution.”¹⁴ As a result, Westar Energy 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.¹⁵

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

... 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.¹⁶

- The publicly-owned Great River Energy Generation & Transmission Cooperative (“GRE”) in Minnesota announced in September 2007 its withdrawal from the proposed Big Stone II Project. According to GRE, four factors contributed most prominently to the decision to withdraw, including uncertainty about changes in environmental requirements and new technology and the fact that “The cost of Big Stone II has increased due to inflation and project delays.”¹⁷
- Similarly, in the spring of 2008, Associated Electric Cooperative, Inc., the wholesale power supplier for 57 electric cooperatives in Missouri, southeast Iowa, and northeast Oklahoma, delayed its plans to build the Norborne 660 MW coal-fired power plant due to increasing costs and other uncertainties. According to AECI:

¹⁴ Available at [http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/\\$file/122806%20coal%20plant%20final2.pdf](http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf).

¹⁵ Id.

¹⁶ Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

¹⁷ See www.greatriverenergy.com/press/news/091707_big_stone_ii.html.

The Norborne project costs have significantly increased in less than three years and are now estimated at \$2 billion due to worldwide demand for engineering, skilled labor, equipment and materials.

The U.S. Department of Agriculture Rural Utilities Service, a traditional funding source for rural electric cooperatives, is currently unable to finance baseload generation for cooperatives. Although AECI's AA credit rating is one of the strongest ratings among all electric utilities nationally, seeking private lending would further increase project costs.¹⁸

There also is increasing uncertainty in the regulatory environment, and Congress continues to debate the environmental and economic impact of reducing greenhouse gas emissions, making the cost of reducing carbon dioxide from power plants unknown.¹⁹

At the same time, AECI noted that it would continue to look at energy efficiency initiatives, natural gas, renewable and nuclear resources to address future generation needs.

Current circumstances are causing more utilities to reconsider their earlier decisions to build coal plants. For example:

- In February 2009, NV Energy, Inc. announced the postponement, due to increasing environmental and economic uncertainties, of its plans to construct a coal-fired power plant in eastern Nevada. The company has said that it will not proceed with construction of the coal plant until the technologies that will capture and store greenhouse gases are commercially feasible, which it believes is not likely before the end of the next decade.²⁰
- Then in early March 2009, Alliant Energy cancelled its plan to build a proposed 649 MW coal-fired plant in Marshalltown, Iowa. According to Alliant, the decision to cancel the project was based on a combination of factors including “the current economic and financial climate; increasing environmental, legislative and regulatory uncertainty regarding regulation of future greenhouse gas emissions” and the terms placed on the proposed power plant by regulators.²¹
- On April 9, 2009, the Board of Tri-State Generation & Transmission, which supplies wholesale power to 18 electric distribution cooperatives in Colorado and 26 in Wyoming,

¹⁸ The Rural Utilities Service of the U.S. Department of Agriculture announced in early March 2008 that it was suspending the program through which it makes loans to rural cooperatives to build new coal-fired power plants. In a letter to Congress, the Administrator of Utility Programs for the Department of Agriculture indicated that loans for new base load generation plants would not be made until the RUS and the federal Office of Management and Budget can develop a subsidy rate to reflect the risks associated with the construction of such plants.

¹⁹ <http://www.aeci.org/NR20080303.aspx>.

²⁰ NV Energy Press Release, dated February 9, 2009.

²¹ <http://www.alliantenergy.com/Newsroom/RecentPressReleases/023120>.

New Mexico and Nebraska, voted to shift its focus from building 2 or 3 proposed coal plants to natural gas, renewable energy and efficiency.²²

- In late 2007 the Louisiana Public Service Commission approved Entergy Louisiana's proposal for the Little Gypsy Repowering Project that would convert an existing natural gas-fired plant into one that burns coal. However, in March 2009, the Louisiana Commission ordered the company to suspend on-going project activities and to demonstrate that the project was still viable.²³ The estimated cost of the project had increased from an initial \$910 million to \$1.76 billion.

In response, Entergy Louisiana has requested a three year extension for the suspension of on-going project activities based on its conclusion that "Given current forecasts of natural gas prices, it now appears that the [combined cycle gas turbine] alternative may be more economic than the [coal-fired] Repowering Project across a range of assumptions."²⁴ Entergy also explained in detail the changed circumstances that had led it to the conclusion that project activities should be suspended:

Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.

The proposed changes in various energy policies by the Obama administration also could have significant effects on the future economics of the Repowering Project. While this administration has only been in office since mid-January, it is becoming more likely that a Renewable Portfolio Standard ("RPS") soon could be implemented. An RPS will require utilities such as [Entergy Louisiana] to incorporate various new technologies into their long-term resource portfolios, including the potential for baseload resources such as biomass facilities and various other intermittent resources such as wind or solar powered generation. The effects of an RPS could mandate that up to 25% of a utility's total energy requirements be provided by renewable resources....

²² "Tri-State changes course, says it will develop gas, renewables over coal," Denver Business Journal, April 11, 2009. Available at <http://www.bizjournals.com/denver/stories/2009/04/06/daily99.html>.

²³ http://blog.nola.com/tpmoney/2009/03/psc_orders_entergy_louisiana_t.html

²⁴ *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana on April 1, 2009, at page 12.

With regard to CO₂ legislation, while the Commission and the Company certainly anticipated that CO₂ regulation would be in place over the life of this Project and incorporated CO₂ compliance costs into its evaluation, there seems to be an emerging momentum to implement CO₂ legislation during the next one to two years. If this occurs, it will allow the Company to gain much greater certainty regarding the cost of compliance with CO₂ legislation and how it will affect the Project economics. CO₂ costs, as the Company has always made clear, are an important factor in the Project economics, and while the possible implementation of CO₂ legislation is not the reason to delay the Project, one of the benefits of the longer-term delay will be greater level of certainty regarding this cost.²⁵

These are only a few examples of the many public and investor-owned utilities, as well as utility regulators, that have decided in recent years to cancel or significantly delay proposed coal-fired power plants.

Finding 3. The construction cost of proposed Cypress Creek Power Station could exceed the \$6 billion figure publicly cited by ODEC.

ODEC has announced an estimated construction cost for the proposed Cypress Creek project of as high as \$6 billion for the two 750 MW units. Although this may be a reasonable estimate at this time, it is possible that the actual construction cost could be higher, and perhaps significantly higher.

In fact, coal power plant construction costs have risen dramatically since the early years of this decade as a result of a worldwide competition for design and construction resources, equipment, and commodities like concrete, steel, copper and nickel. As a result, coal-fired power plants that were estimated to cost \$1,500 per kilowatt in 2002 are now projected to cost in excess of \$3,500 per kilowatt. These increases in estimated coal plant construction costs are illustrated in Figure 1, below, which shows the increases that were announced in the three years between late 2005 and October 2008 for the proposed Meigs County coal plant in Southern Ohio.

²⁵ Ibid., at pages 6-8.

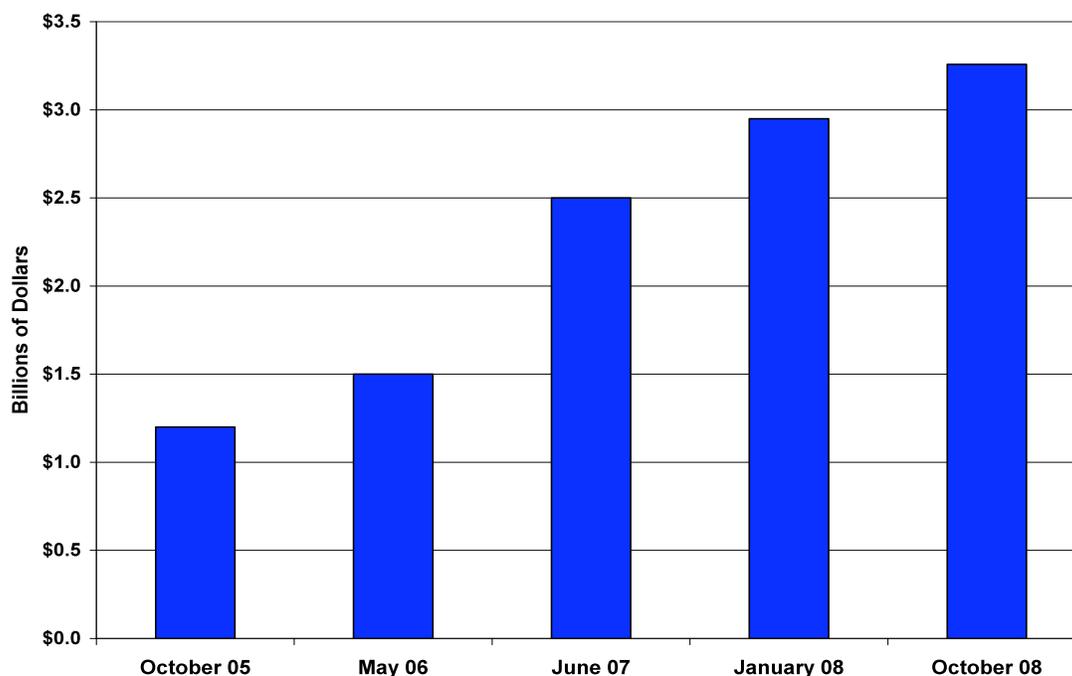


Figure 1. Increases in the estimated cost of building the 960 MW Meigs County Coal Plant (in nominal year dollars, no financing costs).

Like the proposed Cypress Creek Units, the proposed Meigs County plant would be a supercritical pulverized coal plant.

In fact, significant cost increases have been announced for almost all other proposed coal-fired power plants in recent years. For example, the estimated per unit construction cost of Duke Energy Carolina’s Cliffside Project increased by 80 percent between the summer of 2006 and June 2007. Similarly, the projected construction cost of Wisconsin Power & Light’s now-cancelled Nelson Dewey 3 coal plant increased by approximately 47 percent between February 2006 and September 2008.

There are, of course, no guarantees that the construction costs of new coal plants such as Cypress Creek will not increase in future years as a result of the same worldwide competition for power plant design and construction resources, equipment, and commodities that has fueled the recent surge in power plant construction costs. For example, a 15 percent increase in the construction cost of Kansas City Power & Light Company’s Iatan 2 coal plant was announced in the spring of 2008, nearly three years into construction. This shows that even plants that are under construction are not immune to cost increases.

In the past utilities were able to secure fixed-price contracts for their power plant construction projects. However, it is not possible to obtain fixed-price contracts for new power plant projects in the present environment. The reasons for this change in circumstances have been explained as follows by a witness for the Appalachian Power Company, a subsidiary of American Electric Power, in testimony before the West Virginia Public Service Commission:

Company witness Renchek discusses in his testimony the rapid escalation of key commodity prices in the [Engineering, Procurement and Construction] 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.²⁶ [Emphasis added.]

A fall 2007 assessment of AMP-Ohio's proposed coal-fired power plant similarly noted that the reviewing engineers from Burns and Roe Enterprises:

agree 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.²⁷

It is true that the prices of the commodities used to build power plants have decreased since the middle of last year (2008) and there is some anecdotal evidence that the costs of some short-term construction projects have dropped. However, there has been no evidence that these recent decreases in commodity prices actually have led to lower projected construction costs for long-term construction projects such as new coal plants. In fact, the Engineering News-Record, a respected industry source, recently has reported that both its Building Cost and Construction Cost Indices actually rose between March 2008 and March 2009, as did a power plant-specific construction cost index.²⁸

In addition, even though there is now a worldwide economic slowdown, there still is great demand for power plant design and construction resources, equipment and commodities in nations like China and India. At the same time, a number of countries, most particularly the United States and China, have stated their intention to undertake very significant stimulus spending packages on infrastructure repairs and improvements – the Engineering News-Record has reported that these stimulus efforts will pump trillions of dollars into the world economy.²⁹ Such stimulus spending will increase the demand for the same resources and commodities that are used to build new coal-fired power plants and, therefore, can be expected to again lead to higher commodity prices and power plant construction costs over time.

²⁶ Ibid., at page 16, lines 16-20.

²⁷ *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 11-1.

²⁸ March 23, 2009, at pages 32, 37 and 38.

²⁹ Ibid., at page 18.

Finding 4. A comprehensive system for federal regulation of CO₂ and other greenhouse gas emissions is imminent. It is generally expected that this federal regulation will require steep reductions in national greenhouse gas emissions. Since coal is the most carbon intensive fuel, greenhouse gas restrictions are likely to be a significant factor in the economics of coal-fired power plants.

Corporate, government, and financial leaders anticipate imminent greenhouse gas regulation in the U.S., which will pose substantial challenges and create significant new costs for the owners of coal-fired power plants. The Obama Administration indicated in its recently released federal budget that it would seek to establish a cap-and-trade system to reduce greenhouse gas emissions to 14 percent below 2005 levels by 2020 and to 83 percent below 2005 levels by 2050.

Purchasing emissions allowances through such a cap-and-trade system will increase the cost of running power plants that emit CO₂; due to the high carbon content of coal, those plants that are coal-fired will be particularly affected.

The Administration's proposal is one of several. There are two likely avenues for federal regulation of greenhouse gases. Congress could pass legislation, or the U.S. Environmental Protection Agency could adopt regulations to limit greenhouse gas emissions. Both paths are currently under active consideration.

Leaders in both the House and Senate are pursuing plans for aggressive legislative action on climate change during this session. To date, the most substantive legislative proposals have focused on establishing a cap on carbon emissions and allowing affected emitters to trade emission allowances; however, another option would be to establish a tax on greenhouse gas emissions. Legislative proposals in the 111th Congress include an emissions cap with aggressive reduction targets. Proposals announced by Representatives Markey and Waxman, and Representative Van Hollen have included greenhouse gas reduction targets for 2050 of 83% and 85%, respectively, below 2005 emission levels.

Figure 2, below, shows the emissions trajectories that would have been mandated by the proposals that were introduced in the 110th U.S. Congress. These proposals aimed for emissions reductions of 60% to 80% from current levels by 2050. Current proposals are for reductions exceeding 80% below 2005 levels. These targets reflect scientific consensus regarding reductions necessary to stabilize atmospheric CO₂ concentrations at levels that may avoid the most dangerous impacts of climate change.

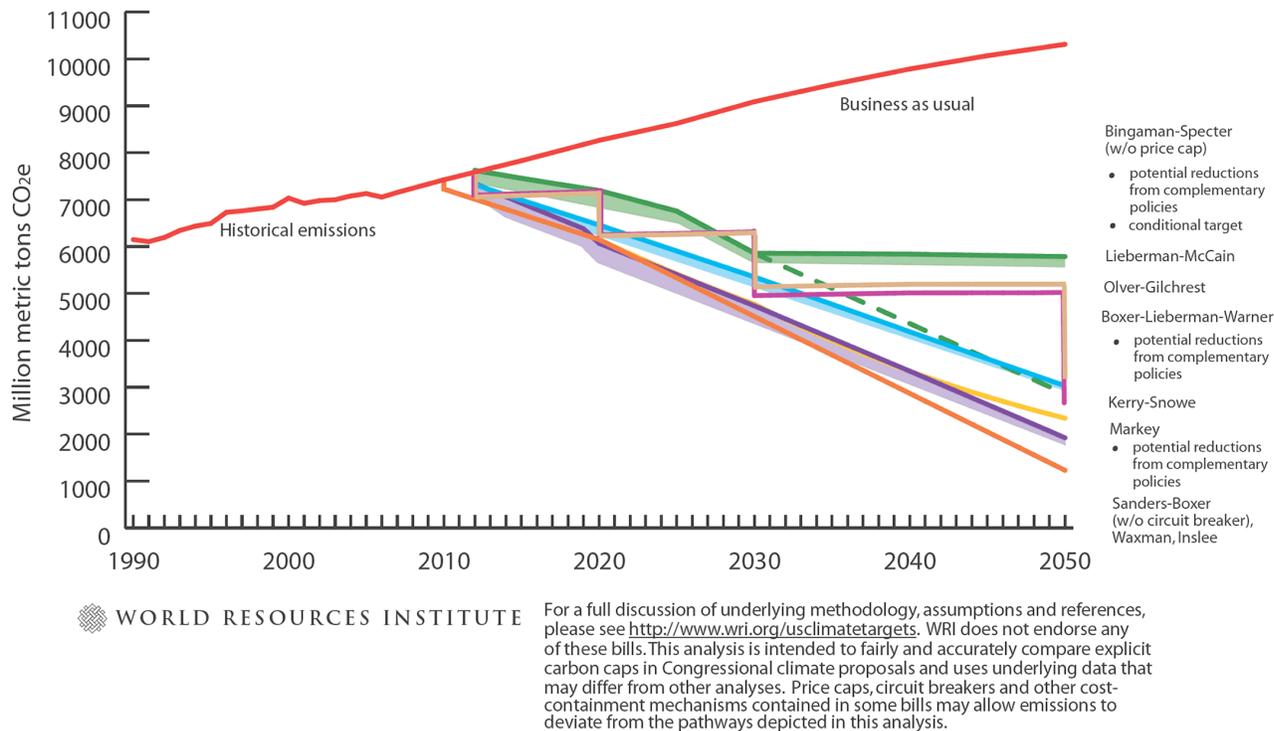


Figure 2. Emissions reductions that would have been required under the climate change bills that were introduced in the 110th U.S. Congress

The plan announced by the Obama Administration, as well as the two recent legislative proposals, would require emissions reductions that approximate the steepest reductions shown in Figure 2. The Edison Electric Institute (EEI) recently issued “Global Climate Change Points of Agreement” that included an agreement that long-term targets (i.e. 2050) should be 80% reduction below current levels.³⁰ Given the plans that have been announced in recent months, and the proposals that were introduced in the previous Congress, the general trend towards strong federal action to address climate change is clear; and it would be a mistake to ignore it in long-term decisions concerning electric resources. Over time the proposals are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

While Congress debates climate change legislation, the EPA is poised to take the next step towards regulating greenhouse gases under the Clean Air Act. In 2007, the U.S. Supreme Court determined that carbon dioxide is an “air pollutant” under the Clean Air Act, and that EPA has the authority to regulate it.³¹ The EPA has now circulated its draft finding, for review by the

³⁰ Edison Electric Institute, “EEI Global Climate Change Points of Agreement,” January 14, 2009

³¹ In this case, Massachusetts and 11 other states sued the US EPA for failing to regulate greenhouse gas emissions from the transportation sector. The Court found that EPA has the standing, the authority, and the obligation to regulation greenhouse gas emissions. The court found that EPA’s refusal to do so or to provide a reasonable explanation of why it could not regulate was arbitrary, capricious and otherwise not in accordance with law. The Supreme Court also found that the “harms associated with climate change are serious and well recognized.”

White House, that greenhouse gas emissions endanger public health and welfare.³² The Obama Administration has stated its preference for a legislative solution to addressing climate change; however, EPA's regulatory authority provides an alternate option should Congress fail to act.

Unfortunately for cooperative members and their ratepayers, ODEC's plan to build a large coal-fired power plant would lock the company into years of high CO₂ emissions just at a time when those emissions will become costly. These costs would become the burden of ratepayers.

In its January 28, 2008 assessment of the *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's noted that "the single biggest challenge regulated electric utilities will tackle is the discharge of carbon dioxide (CO₂) into the air"³³ Standard & Poor's subsequently issued a report on *The Credit Cost of Going Green for U.S. Utilities*, in March 2008, in which it concluded that:

The debate is over. Not the one concerning climate change, but the one about whether the U.S. will act to limit greenhouse gas emissions to address the possibility that human activities are harming the planet. By now it's a foregone conclusion that the U.S. will pass laws that call for significant reductions in carbon dioxide (CO₂). The only uncertainty is the details of how much and by when. . . . So for electric utilities, the credit question is not so much whether higher costs related to controlling emissions are coming, but rather when and how high they'll actually go.³⁴

More recently, in its January 2009 Electric Industry Outlook, Moody's Investors Services also has warned that:

The prospect for new environmental legislation—particularly concerning carbon dioxide—represents the biggest emerging issue for electric utilities, given the volume of carbon dioxide emissions and the unknown form and substance of potential CO₂ legislation.³⁵

Moody's also emphasized that credit risk for utilities arises from the uncertain costs and format of emissions regulation, acceleration of potential climate change legislation, and the possibility that rate regulators will balk at rising costs when consumers reach their tolerance level for cost increases, particularly in light of recessionary pressures.

Finding 5. ODEC has said that the 1,500 MW Cypress Creek Power Station will emit approximately 14.6 million tons of CO₂ each year. There is currently no commercially viable technology for capturing CO₂ emissions from a pulverized coal plant like Cypress Creek.

³² "White House begins review of EPA endangerment proposal," Greenwire, March 23, 2009.

³³ *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's, January 28, 2008, at page 2.

³⁴ *The Credit Cost of Going Green*, Standard & Poor's, March 2008, at page 15.

³⁵ *Moody's Global Infrastructure – Industry Outlook: "U.S. Investor-Owned Electric Utilities;"* Moody's Investors Services. January 2009.

ODEC has said that the proposed Cypress Creek Power Station will emit approximately 14.6 million tons of CO₂ each year.³⁶ That would mean that the Cypress Creek station would emit an additional 876 million tons of CO₂ into the atmosphere if it is operated for 60 years unless some technological fix, or silver bullet, is developed to capture CO₂ emissions from pulverized coal plants like Cypress Creek and permanently sequester it in the ground.

However, there is currently no technology for reducing carbon emissions from a power plant that could be added once the timing and stringency of federal emissions limits are known. Unlike for other power plant air pollutants like sulfur dioxide and oxides of nitrogen, there currently is no commercially demonstrated, economically viable method for the post-combustion removal of CO₂ from pulverized coal plants at full scale. Some technologies are starting to be tested with plans for scale up. But it might be years, if not decades, before there will be commercially viable post-combustion technology for the capture and sequestration of greenhouse gas emissions from pulverized coal-fired power plants like the proposed Cypress Creek Power Station. The Edison Electric Institute, for example, has said that it does not expect carbon capture and storage technologies to be commercially available until 2020 or 2025. And even that timeline might be overly optimistic.

A number of independent sources such as Duke Energy, the electric industry's Edison Electric Institute, the Massachusetts Institute of Technology and the U.S. Department of Energy's National Energy Technology Laboratory have estimated that adding carbon capture technology would increase the cost of generating power at a pulverized coal-fired plant by 60 percent to 80 percent. If these costs of carbon capture were included, the projected cost of generating power at coal-fired power plants like Cypress Creek would be 12 to 14 cents per kilowatt hour, significantly higher than the cost of other supply and demand-side alternatives. The costs of transporting and permanently sequestering the CO₂ in the ground would be in addition to these production costs.

However, the bottom line is that it is not prudent to build a new coal-fired power plant with only a hope that there will be a technology developed at some point that can be retrofitted onto the new coal plant in order to capture and, ultimately, sequester 90 percent or more of its CO₂ emissions. Because if carbon capture and sequestration technology is not added to the Cypress Creek Power Station, the ratepayers of ODEC's member cooperatives instead would have to pay hundreds of millions to more than a billion dollars each year to buy allowances to cover the plants' CO₂ emissions.

Finding 6. ODEC's consumer-members will face significant costs associated with the decision to lock in the carbon emissions from the proposed Cypress Creek Power Station for decades.

Regardless of whether federal restrictions on greenhouse gas emissions ultimately take the form of an emissions cap with tradable allowances, or a tax on emissions, power plant owners (and other emission sources) will bear costs associated with emissions. Since coal is the most carbon-intensive fuel, the compliance costs for a coal-fired power plant are likely to be substantial and must be taken into account in such a long-lived investment.

³⁶ <http://www.cypresscreekpowerstation.com/questions031809.php>.

In an interview with the Financial Times, Todd Stern, the U.S. Special Envoy on Climate Change has warned that businesses must not sink money into high-carbon infrastructure unless they are willing to lose their investments within a few years.³⁷

In the Obama administration's starkest rebuke yet to industry over global warming, Todd Stern, special envoy for climate change at the state department, said "high-carbon goods and services will become untenable" as the world negotiated a new agreement to cut carbon emissions.

Investors should take note, he warned, that high emissions must be curbed, which would hurt businesses that failed to embark now on a low-carbon path.

"How good will the business judgment of companies that make high-carbon choices now look in five, 10, 20 years, when it becomes clear that heavily polluting infrastructure has become deadly and must be phased out before the end of its useful life?"

Companies investing in such goods and services - such as coal-fired power plants and gas-guzzling cars - could start to incur heavy economic penalties in the near future for their greenhouse gas output.³⁸

Some coal plant proponents claim that under a greenhouse gas emissions cap, a significant number or even all of the emissions allowances necessary for operation will be distributed free to generators. While early proposals for allowance distribution were modeled after the acid rain provisions of the Clean Air Act, (i.e., distributing allowances for free to affected entities,) current proposals all include provisions to auction 60% to 100% of allowances. Free allowance distribution to covered entities is considered as a transition mechanism, if at all.

Indeed, the Obama Administration has stated its preference for 100 percent auctioning of allowances in a federal cap-and-trade system, though recently a senior administration official indicated that the Administration is considering a gradual transition to the full auction.³⁹ This would be consistent with the recommendations of a number of groups, including, for example, the National Commission on Energy Policy⁴⁰ which has recommended that "new coal plants built without [carbon capture and sequestration] not be "grandfathered" (i.e., awarded free allowances) in any future regulatory program to limit greenhouse gas emissions."⁴¹ EEI also includes allowance allocations to merchant coal generation and utilities as a mechanism in a gradual transition to full auction.⁴²

³⁷ http://www.ft.com/cms/s/0/ffb6b5bc-23d3-11de-996a-00144feabdc0.html?ncllick_check=1

³⁸ Ibid.

³⁹ "White House might agree to delay in greenhouse gas rules," Boston Globe, April 9, 2009, page A13.

⁴⁰ The National Commission on Energy Policy is a bipartisan group of 20 energy experts from industry, government, academia, labor, consumer and environmental protection.

⁴¹ *Energy Policy Recommendations to the President and the 110th Congress*, National Commission on Energy Policy, April 2007, at page 21. Available at http://www.bipartisanpolicy.org/files/news/contentFiles/NCEP-Recom-final-single_4773e92b6f5c2.pdf

⁴² Edison Electric Institute, "EEI Global Climate Change Point of Agreement," January 14, 2009.

Another proposal for federal climate change policy specifically prohibits the distribution of free allowances to power plants licensed after 2009.⁴³ In the Regional Greenhouse Gas Initiative, the first carbon cap that has been implemented in the U.S. for the electric sector, all of the states that are participating have decided to auction 100% of the allowances.

The 2007 Massachusetts Institute of Technology interdisciplinary study on *The Future of Coal* warned:

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 CO₂ 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.⁴⁴

According to Standard and Poor’s:

Customers of those utilities with higher levels of carbon intensity will be more exposed to rate increases than customers of utilities with lower carbon intensity. The magnitude of the rate increases will depend on the level of carbon costs and the extent of management’s commitment to the preservation of credit quality.⁴⁵

Numerous modeling analyses of federal policy proposals for mandatory greenhouse gas reductions in the U.S. are available (e.g. from government agencies like the Energy Information Administration and the Environmental Protection Agency, educational institutions such as the Massachusetts Institute of Technology and Duke University, consulting firms, and various other organizations). A list of these analyses is given in Appendix A. Though these analyses precede the recent legislative proposals from the Administration and Congress, their results are relevant because the greenhouse gas emission reduction targets in recent proposals are comparable to the most stringent targets in the plans that have been modeled.

In total, these modeling analyses examined more than 75 different scenarios. These scenarios reflected a wide range of assumptions concerning important inputs such as: the “business-as-usual” emissions forecasts; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress and the cost of alternatives; and the presence

⁴³ US Climate Action Partnership, *A Blueprint for Legislative Action*, January 15, 2009.

⁴⁴ *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*, 2007, at page (xiv). Available at http://web.mit.edu/coal/The_Future_of_Coal.pdf.

⁴⁵ Standard and Poor’s, *The Cost of Carbon – Credit Quality Implications for Public Power and Cooperative Utilities*, March 27, 2008, at page 9.

or absence of a “safety valve” price. The ranges of the levelized CO₂ prices developed in each of these modeling analyses are shown in Figure 4 below.

Based on a number of factors, including our assessment of the results of these modeling analyses, Synapse has developed a set of CO₂ price forecasts that we believe provides a reasonable range of possible future CO₂ allowance values. These forecasts are presented in Figure 3:

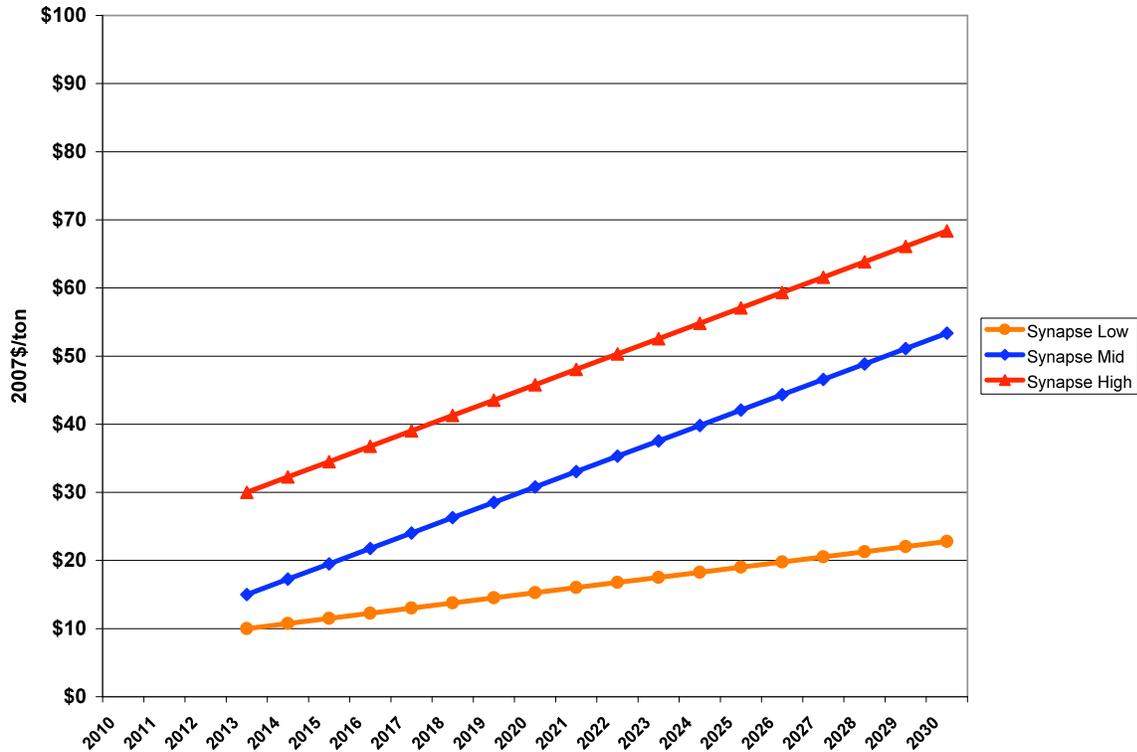


Figure 3. Synapse 2008 CO₂ allowance price forecasts

The 2008 Synapse Low CO₂ Price Forecasts starts at \$10/ton in 2013, in 2007 dollars, and increases to approximately \$23/ton in 2030. This represents a \$15/ton levelized price over the period 2013-2030. The 2008 Synapse High CO₂ Price Forecast starts at \$30/ton in 2013 and rises to approximately \$68/ton in 2030. This High Forecast represents a \$45/ton levelized price over the period 2013-2030. Synapse also has prepared a Mid CO₂ Price Forecast that starts close to the low case, at \$15/ton in 2013 and climbs to \$53/ton by 2030. The levelized cost of this Mid CO₂ price forecast is \$30/ton.

Synapse first developed a set of CO₂ price forecasts in the spring of 2006. However, significant developments since that time led Synapse to re-examine and raise those CO₂ price forecasts this past summer to ensure that they reflect an appropriate level of financial risk associated with

greenhouse gas emissions.⁴⁶ Most importantly, the political support for serious climate change legislation has expanded significantly in federal and state governments, as well as in the public at large, as the scientific evidence of climate change has become more certain. Concurrently, the new greenhouse gas regulation bills proposed in the U.S. Congress have contained emissions reductions that were significantly more stringent than would have been required by proposals introduced in earlier years. Moreover, an increasing number of states have adopted policies, either individually and/or as members of regional coalitions, to reduce greenhouse gas emissions. Further, additional information has been developed regarding technology innovations in the areas of renewable resources, energy efficiency, and carbon capture and sequestration, leading to greater clarity about the cost of emissions mitigation; however, cost estimates for many of these technologies are still in the early stages. Taken together these developments lead to higher financial risks associated with future greenhouse gas emissions and justify the use of higher projected CO₂ emissions allowance prices in electricity resource planning and selection for the period 2013 to 2030 (as discussed below).

Figure 4, below, compares the range of CO₂ prices that Synapse currently recommends for use in resource planning with the results of the modeling analyses of the major climate change legislation proposed in the 110th U.S. Congress. As can be seen, the CO₂ prices recommended by Synapse are very reasonable compared to the range of CO₂ emissions allowance prices that could result from adoption of the major greenhouse gas regulatory legislation that was introduced in the last U.S. Congress. In fact, under many possible scenarios, CO₂ allowance prices could substantially exceed the high ends of the price range that Synapse recommends for use in resource planning assessments.

⁴⁶ See the July 2008 report *Synapse 2008 CO₂ Price Forecasts* available at <http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf>

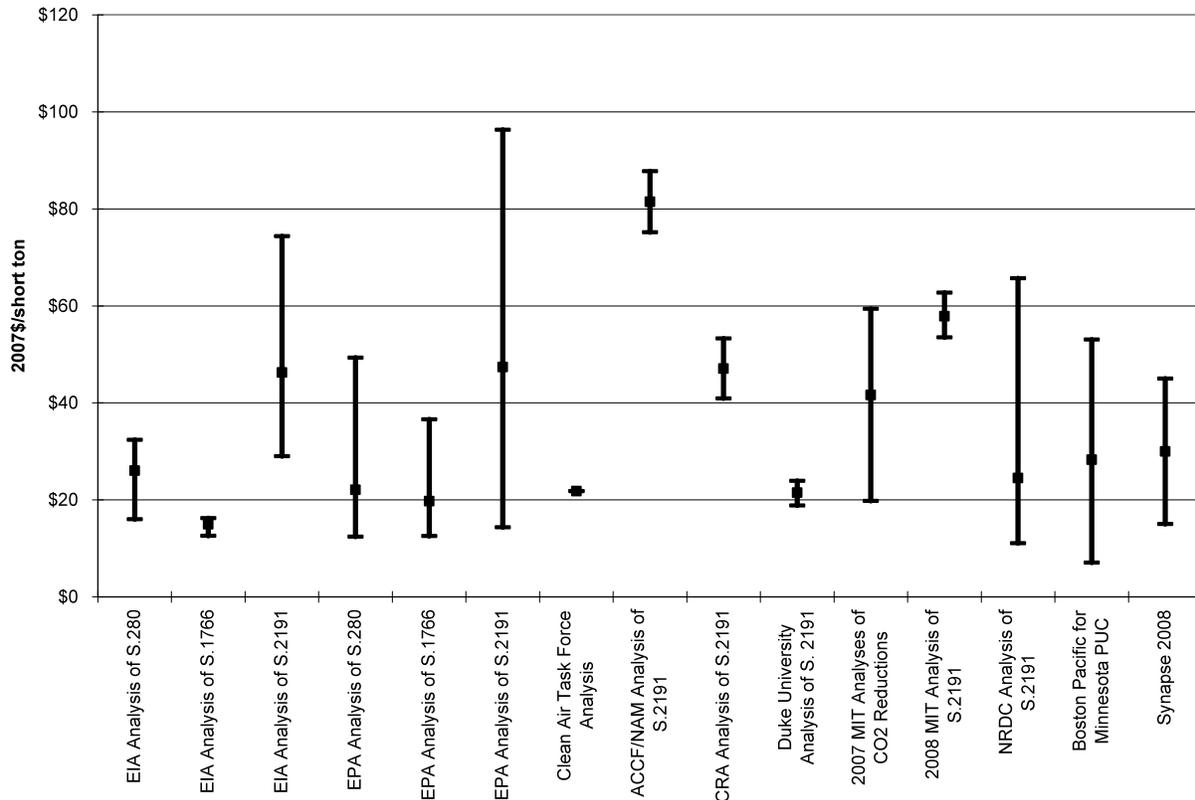


Figure 4. CO₂ prices used by Synapse vs. results of modeling analyses of major bills in the 110th U.S. Congress – levelized CO₂ prices (2013-2030, in 2007 dollars)

As was discussed above, carbon capture and sequestration technology is currently not viable, and when it becomes viable, it will be at significant cost to utilities, and therefore, to consumers. But if carbon capture and sequestration technology is not added to the Cypress Creek units, ODEC's consumer-members instead would have to pay hundreds of millions to more than a billion dollars each year to buy allowances to cover the plants' CO₂ emissions – allowances that would be auctioned as part of the cap-and-trade program. The annual costs for purchasing the allowances for the approximate 14.6 million tons of CO₂ that ODEC has said that Cypress Creek can be expected to emit each year are shown in Figure 5, below. The annual costs in this Figure reflect the Synapse High, Mid and Low CO₂ price trajectories shown in Figure 3, above. Although Figure 5 only goes through 2030, it is reasonable to anticipate that ODEC's member cooperatives and their ratepayers would have to pay these increasing annual costs right through the end of the operating lives of the Cypress Creek units, or until the capability for carbon capture and sequestration is added to the facility – which also would create very substantial costs for ratepayers, as noted earlier.

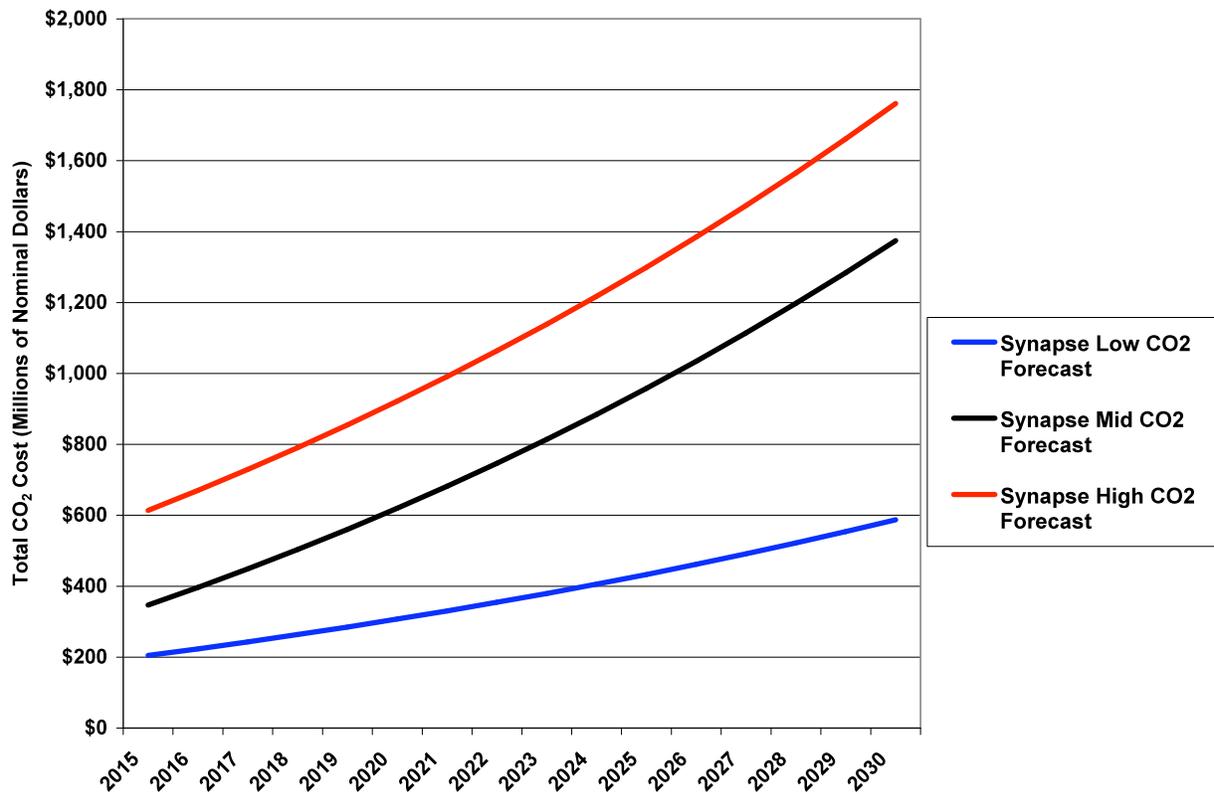


Figure 5. Cypress Creek Power Station annual CO₂ costs (millions of nominal dollars).

Thus, if it builds both units of the Cypress Creek project, ODEC’s member cooperatives and their ratepayer may have to pay between \$223 million and \$670 million for the CO₂ emitted by that plant in 2016, and these costs could rise to between \$587 million to \$1.76 billion by 2030. As shown in Figure 6, below, the levelized cost of power from Cypress Creek would be about 9.1 cents per KWh at Synapse’s low CO₂ price forecast, about 10.9 cents per KWh at Synapse’s mid CO₂ price forecast, and 12.3 cents per KWh at Synapse’s high CO₂ price forecast.

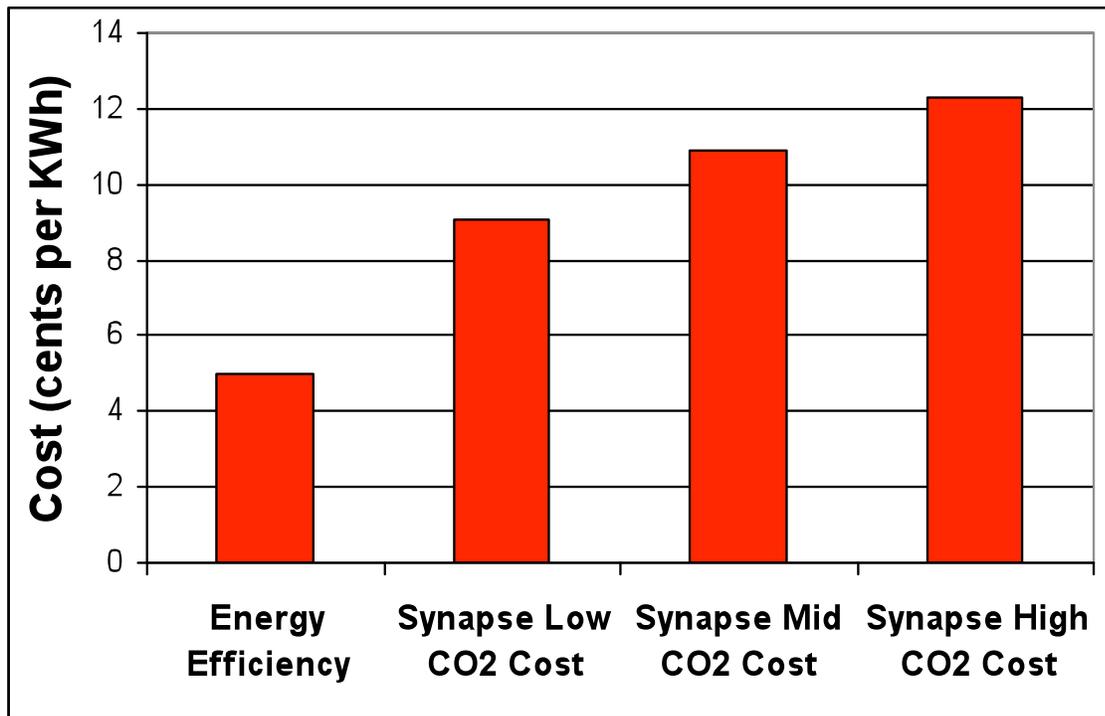


Figure 6. Levelized cost of power from the Cypress Creek Power Station with Synapse CO₂ costs.⁴⁷

ODEC has acknowledged in its Form 10-K Report for 2008 that “Regulation of carbon emissions and other greenhouse gases may significantly increase our costs and result in our purchasing additional energy in the market” and has identified this as a “potential risk factor” that “should be considered carefully when evaluating ODEC.”⁴⁸

ODEC also noted that other environmental regulation may limit its operation or increase its costs or both.⁴⁹

Finding 7. ODEC has not presented evidence that building and operating the proposed Cypress Creek Power Station is the lowest cost option for ODEC’s consumer-members.

Old Dominion Electric Cooperative’s President has said that “our number one goal continues to be providing our members and their consumer-owners a reliable, environmentally-balanced power supply at the lowest possible cost.”⁵⁰ ODEC further claims on its website that “coal is the

⁴⁷ This Figure reflects a very conservative levelized cost of 3 to 5 cents per KWh for energy efficiency. See Finding 10 below.

⁴⁸ At pages 13 and 14.

⁴⁹ *Ibid.*

⁵⁰ President’s Message, ODEC website. Accessed March 24, 2009. Available at <http://www.odec.com/View.aspx?page=about/president>

most cost-effective fuel source option for ODEC's consumer members."⁵¹ However, the confluence of factors described in this report make it unlikely that investment in a new coal-fired facility at this time of regulatory uncertainty and increasing costs will be the lowest cost option for customers. This is especially true given the project's \$6 billion estimated construction cost, the likely costs of complying with federal regulation of CO₂ emissions, potential structural changes in the natural gas market leading to lower prices, both current and long-term, and the availability of low cost energy efficiency.

We have found no publicly available evidence on ODEC's website or elsewhere that supports the claim that coal, indeed, is the most effective fuel source for its consumer-members. For example, in response to a question at the March 18, 2009 Air Permit Open House, ODEC said the Cypress Creek plant still is cost-effective even considering President Obama's commitment to a cap on carbon emissions:

ODEC factored the cost of carbon into its evaluation of generation technologies. Our evaluation continues to show that even with a carbon tax or cap and trade program for CO₂, a supercritical pulverized coal/biomass power station is the most economical (and environmentally balanced) generation choice for meeting ODEC consumer-member needs.⁵²

Unfortunately, ODEC did not provide any analyses or other evidence to support this claim or to detail precisely how it had incorporated a carbon tax or cap and trade program for CO₂ into its planning analyses. ODEC was not even willing to provide the levelized production costs for the proposed plant and the nuclear, hydro, solar, wind, and biomass alternatives.⁵³

Without having an opportunity to review ODEC's resource planning assessments and analyses, it is impossible to validate its claims that the Cypress Creek project is economic under a likely carbon tax or cap-and-trade program for CO₂. It also is impossible to determine whether ODEC has considered reasonable ranges of uncertainty in the most critical input assumptions such as plant capital costs, CO₂ emissions allowance prices, and natural gas prices. It also is impossible to determine whether ODEC reasonably considered all feasible energy efficiency and renewable resource options or unreasonably constrained those alternatives in its planning analyses.

Through our work analyzing utility resource planning, Synapse has identified a set of good, or "prudent," electric resource planning practices:

- Actively seek out relevant information.
- Rely on up-to-date and realistic construction cost estimates.
- Include reasonable CO₂ price forecasts in the reference case, and analyze high and low sensitivities.

⁵¹ ODEC, Cypress Creek Power Station, Frequently Asked Questions, accessed March 19, 2009. Available at <http://www.cypresscreekpowerstation.com/faq.php#18>

⁵² <http://www.cypresscreekpowerstation.com/questions031809.php>,

⁵³ Ibid.

- Include full consideration of alternatives.

We also have identified a set of poor, or “imprudent,” planning practices:

- Passive attitude toward information.
- Rely on out-of-date construction cost estimates.
- Ignore CO₂ price, look at a single, low set of CO₂ prices, or treat CO₂ “at the end” as a sensitivity case.
- Overly constrain alternatives such as renewable resources and energy efficiency.
- Claim that a proposed coal plant is part of a strategy or plan for reducing CO₂ emissions.

Again, without being able to examine ODEC’s planning analyses in detail, it is impossible to determine the extent to which it incorporates the prudent, and avoids the imprudent, planning practices listed above. We recommend, therefore, that ODEC make its planning analyses public so that its consumer-members can evaluate reasonableness of the plant whose costs they will bear.

Finding 8. ODEC’s consumer-members will be committed to paying all of the costs associated with the proposed Cypress Creek Power Station for at least 45 years.

The Cypress Creek Power Station will be financed by debt issuances secured by 45 year wholesale power contracts from 11 member cooperatives. Consequently, the member cooperatives and their ratepayers will then be committed to paying all of the costs of generating power at the Cypress Creek Station including the costs of complying with federal climate change requirements. As discussed in the Findings throughout this report, the costs associated with constructing and operating a new coal-fired power plant at this time could be substantial, and investment in a new coal-fired power plant exposes the member cooperatives and their ratepayers to enormous financial uncertainty and likely costs.

Of course, it is the very existence of ratepayers that gives public and investor utilities a reputation as a sound low-risk investment; but this does not justify the making of risky new investments that would expose ODEC’s consumer-members to the high costs of expensive new power plants and the high costs of complying with likely federal regulation of greenhouse gas emissions. In order to understand the potential costs that they are exposed to, the member cooperatives and their ratepayers deserve to have access to the planning analyses that ODEC says are the basis for its decision to pursue the Cypress Creek Station and for its determination that “coal is the most cost-effective fuel option.”

Finding 9. ODEC has not demonstrated a need for all of the 1,500 MW from the proposed Cypress Creek Power Station until 2030 or later. It also has not demonstrated a need for all of the 750 MW from one of the proposed units at Cypress Creek until approximately 2020.

ODEC presented what it called a ‘Gap Analysis’ as part of its March 18, 2009 Air Permit Information Briefing. This Gap Analysis is presented below. The annual gaps between ODEC’s projected PJM load obligations and its existing capacity resources, according to ODEC, are indicated by the black portion of each bar.

The Gap Analysis clearly shows that ODEC does not need all of the 1,500 MW of capacity from the Cypress Creek Power Station to meet its PJM load obligations until approximately 2030 and does not even need all of the 750 MW from just one of the units until approximately 2020.⁵⁴ The pattern of increasing loads shown in the GAP Analysis also suggest that instead of building two 750 MW units at Cypress Creek, ODEC should be adopting a more flexible plan that allows for the addition of needed capacity in smaller increments as need develops, and that allows for aggressive implementation of energy efficiency to delay the need for additional supply side capacity as long as possible.

However, this Gap Analysis may overstate ODEC’s need for new generating capacity as it is not clear whether it reflects:

1. The capacity from ODEC’s planned participation in the North Anna 3 nuclear power plant.
2. ODEC’s loss of its largest member cooperative, NOVEC, as of the end of 2008.
3. The impact of the ongoing economic recession and financial crisis on ODEC’s current and future loads.
4. The legislative goal (in Section 676-102 of the Code of Virginia) that the consumption of electric energy be reduced by 10 percent of the amount of energy consumed in 2006 by the year 2022.
5. The new more aggressive energy efficiency investments that will be funded by the stimulus monies provided by the federal government through the American Recovery & Reinvestment Action.

Any or all of these factors would delay ODEC’s need for capacity from the Cypress Creek project even further into the future.

For example, ODEC’s 10-Q Report for the Third Quarter of 2008⁵⁵ has noted that its energy sales to its member distribution cooperatives were flat between the Third Quarter of 2007 and the same 3 month period in 2008. However, its member cooperatives’ energy sales for the three

⁵⁴ In other words, the black bars showing the gaps between ODEC’s PJM load obligations and its existing capacity resources do not reach 750 MW until approximately 2020 and 1,500 MW until approximately 2030.

⁵⁵ Utilities like ODEC and other companies are required to file quarterly financial reports with the U.S. Securities and Exchange Commission. These are called 10-Q Reports.

months ending September 30, 2008 actually were 3.8 percent lower than the previous year if the sales in the additional territory acquired by one of the cooperatives during the year were excluded.⁵⁶

ODEC's 10-K Report for 2008⁵⁷ indicates that its energy sales to member distribution cooperatives increased by approximately 3 percent but it is unclear the extent to which this increase was the result of the acquisition of additional territory by one of ODEC's member cooperatives.⁵⁸ In addition, ODEC's sales of excess purchased and generated energy to non-members decreased by 40.1 percent between 2007 and 2008.⁵⁹

ODEC's loads and sales in 2009 and subsequent years likely will be significantly lower due to the loss of NOVEC which was responsible for 28.2 percent of ODEC's sales revenues in 2008.⁶⁰ As noted above, ODEC has not indicated whether its Gap Analysis reflects the loss of this significant member cooperative.

Other utilities in Virginia also experienced declining sales in 2008. For example, Dominion Virginia Power's sales for 2008 were down 1 percent from 2007, after growing by 6 percent from 2006 to 2007. Given that the economic forecast for 2009 in Virginia (and indeed the rest of the nation) is grim, it is reasonable to expect that energy sales, and most likely peak loads, will remain flat or even decline further in 2009 and perhaps in subsequent years as well.⁶¹

Another regional utility, Duke Energy Carolinas, currently assumes that energy sales in 2009 will not increase from 2008 levels. Jim Rogers, Chairman and CEO of Duke Energy also has said that his customers' reduced consumption reflected more than just the economic recession: "Something fundamental is going on here."⁶²

The recent declines in energy sales raise several critical questions for ODEC's resource planning:

- Are the reduced sales experienced in 2008 merely the result of the economic recession or are there longer-term factors at work?
- When the economy recovers, will ODEC's sales and loads grow at the rates that it has experienced in recent years?

⁵⁶ ODEC Form 10-Q for the Period Ending September 30, 2008, at page 10.

⁵⁷ ODEC also is required to file an annual financial report with the U.S. Securities and Exchange Commission. This is called a 10-K Report.

⁵⁸ ODEC Form 10-K for the Twelve Months Ending December 31, 2008, at page 33.

⁵⁹ Ibid., at page 35.

⁶⁰ Form 10-K for the Twelve Months Ending December 31, 2008, at page 5.

⁶¹ Indeed, many economists, including some in the Federal Reserve Bank, believe that the current recession could remain deep for a number of years with a very slow recovery. For example, see the minutes of the January 27, 2009 meeting of the Federal Open Market Committee and Standard & Poor's, *U.S. Public Power Outlook: 2009 Could Provide Some Shocks*, January 20, 2009, at page 4.

⁶² *Surprise Drop in Power Use Delivers Jolt to Utilities*, The Wall Street Journal, November 21, 2008.

- What is ODEC’s currently projected need for new capacity given the reduced sales experienced in 2008, the loss of NOVEC, the likely extended economic recession/slowdown and financial crisis and the impact of expected funding for new energy efficiency efforts?

When asked about the need for the Cypress Creek project at the March 18, 2009 Air Permit Open House, ODEC said that the state will be 4,000 MW of capacity short over the next decade.⁶³ This explanation, plus the fact that ODEC will not need all of the capacity from even one of the two units at Cypress Creek until 2020 or later, suggests that Old Dominion is building the 1,500 MW at Cypress Creek more to serve off-system loads than to meet its own system requirements and/or will seek to add other utilities as participants in the project. Building a new generating plant to serve off-system loads is risky and could lead to severe financial difficulties for ODEC and its consumer-members if the power from the plant is not cost-competitive in wholesale markets, or if the off-system loads that ODEC currently projects do not materialize due to increased energy efficiency efforts or another prolonged slowdown in the economy. In fact, as noted above, ODEC’s sales to non-members decreased by 40.1 percent between 2007 and 2008.

Moreover, it appears that the 4,000 MW of capacity that ODEC says will be needed in Virginia over the next decade does not reflect the following:

1. The impact of the ongoing economic recession and financial crisis.
2. The effect of the legislative target to reduce consumption of electric energy by 10 percent of the energy consumed in 2006 by the year 2022.⁶⁴
3. The impact of the new federal stimulus funds directed towards energy efficiency investments.
4. The substantial potential for renewable resources in the state, particularly offshore wind.
5. Whether consumers will reduce their consumption due to concerns over rates or climate change.
6. The other central station generating facilities currently under construction or proposed for Virginia.

The example of the Vermont Electric Cooperative (“VEC”) represents the danger that overbuilding to meet prospective off-system loads can pose. In the 1970s, VEC borrowed funds to invest in a number of proposed power plants as part of a conscious attempt to assemble a stable number of baseload facilities much larger than would be needed to serve its own loads, which would be used to make off-system sales to other cooperatives and to private utilities in the northeast. However, the costs to build the plants rose significantly, some projects were

⁶³ See <http://www.cypresscreekpowerstation.com/questions031809.php>.

⁶⁴ For example, the 2007 Virginia Energy Plan concluded that if the conservation goal set in the 2007 legislation were met, the state would need to add only an additional 2,358 MW of new generating capacity. At page 17.

cancelled, and the projected loads did not materialize. As a result, VEC entered bankruptcy in the mid 1990s.⁶⁵

⁶⁵ Prefiled Testimony of William Steinhurst on behalf of the Vermont Department of Public Service, Vermont Public Service Board Docket Nos. 5630 and 5632, July 6, 1993, at page 21.