Synapse
Energy Economics, Inc.

Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan

by

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Conclusion: Synapse Energy Economics, Inc. ("Synapse") has completed a preliminary assessment of East Kentucky Power Cooperative's ("EKPC") 2009 resource plan. The source materials for this assessment have included EKPC's April 29, 2009 IRP filing and other publicly available documents.

We have concluded that EKPC has proposed a resource plan that remains heavily dependent on new coal-fired generation facilities with only relatively minor contributions from energy efficiency and renewable resources. For this reason, EKPC's proposed resource plan entails excessive uncertainty and risk for its member cooperatives and their retail customers.

- Uncertainty as to the availability of financing in capital markets and financing costs.
- Uncertainty whether projected loads and energy sales (internal and off-system) will materialize.
- Uncertainty as to the greenhouse gas emissions reductions that ultimately will be required as a result of federal, regional or state action, and the cost of compliance with likely future regulations.
- Uncertainty whether post-combustion carbon capture and sequestration will prove to be technically viable as a retrofit for new coal plants like the new Spurlock Unit #3 and Spurlock Unit #4 and the proposed Smith Unit #1.
- Uncertainty as to the costs and economic viability of post-combustion carbon capture and sequestration for coal plants, if it does prove technically viable.
- Uncertainty as to coal power plant construction costs and schedules.
- Uncertainty as to whether the federal government will adopt a national Renewable and Energy Efficiency 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 the impact of more stringent regulations for current criteria pollutants (such as NO_x, SO_2 and mercury).

The confluence of factors – economic recession, construction cost trends, uncertainty about the details of federal greenhouse gas restrictions, impending costs associated with carbon emissions – means that this is a terrible time to make a significant investment in a long-lived carbon-intensive resource such as another new coal-fired power plant. Such an investment locks customers into paying for a course of action that could prove, and is indeed likely to prove an ill-chosen option as greater certainty emerges over the next several years.

In light of these significant risks, it would be better to adopt a resource plan that allows for (1) the postponement of decisions concerning large capital expenditures for new coal-fired power plants and (2) the flexibility to modify course as circumstances change. EKPC's resource plan that continues a near-term commitment to capital-intensive coal investments is the wrong choice in today's uncertain economic and financial conditions.

In particular, we have found:

Finding 1. EKPC's plan to build yet another baseload coal plant ensures coal will continue to dominate its resource mix for decades. EKPC's existing resource mix is predominantly coal with some gas-fired units and hydro plus minimal amounts of landfill gas – in fact, all of EKPC's baseload generating facilities are coal-fired. EKPC's 2009 resource plan reveals that it will continue to be very heavily coal-dependent for decades unless it undertakes very aggressive efforts on energy efficiency and renewable resources.

Finding 2. EKPC is continuing its expensive generation expansion program in a period of great economic and financial uncertainty.

Finding 3. A comprehensive system for federal regulation of carbon dioxide (CO_2) and other greenhouse gas emissions is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions. However, under its proposed resource plan, EKPC's annual CO_2 emissions will increase, not decrease, as a result of the addition of the three new coal units, Spurlock Unit #3, Spurlock Unit #4 and the proposed Smith Unit #1.

Finding 4: EKPC's new Spurlock Unit #3, Spurlock Unit # 4 and Smith Unit #1 coal units would each emit approximately 2.5 million tons of CO_2 each year. There currently is no commercially viable technology for capturing CO_2 emissions from these CFB coal plants.

Finding 5. Ratepayers will face significant financial risk associated with the decision to lock in increasing carbon emissions for the coming decades at a time when those emissions will be costly.

Finding 6. The construction cost of proposed Smith Unit #1 could be higher than EKPC's currently estimated $766 million cost.

Finding 7. 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 90 coal power plant cancellations, delays and rejections by state regulatory commissions.

Findings

Finding 1. EKPC's plan to build yet another baseload coal plant ensures coal will continue to dominate its resource mix for decades. EKPC's existing resource mix is predominantly coal with some gas-fired units and hydro plus minimal amounts of landfill gas – in fact, all of EKPC's baseload generating facilities are coal-fired. EKPC's 2009 resource plan reveals that it will continue to be very heavily coal-dependent for decades unless it undertakes very aggressive efforts on energy efficiency and renewable resources.

All of EKPC's existing baseload generating units are coal-fired and, therefore, are significant emitters of greenhouse gases such as CO_2. In fact, EKPC has added two new coal plants, the Spurlock Unit #3 Unit in 2005 and Spurlock Unit #4 on April 1, 2009. It currently plans to complete another new coal plant, Smith Unit #1, in approximately 2014, as well as adding several hundred megawatts ("MW") of new gas-fired units which also emit CO_2.[1]

EKPC claims that it has "proposed a diverse resource plan as a strategy for supplying least cost power supply to its 16 member distribution systems."[2] However, our preliminary review of this filing finds that instead of proposing a "diverse resource plan," EKPC intends to increase its already heavy dependence on fossil-fired resources with only minor contributions from energy efficiency and renewable resources. For example:

- Basically all of EKPC's near-term capacity additions (next 10 years) are planned to be fossil-fired.

- EKPC's 2009 resource plan includes only small amounts of energy efficiency. For example, EKPC projects that its current and new demand side programs will save perhaps 480,000 MWh of energy in 2018. This is only 3.1 percent of its projected 15 million MWh of retail sales.

  Studies in nearby states have shown that there is significantly more potential for economic energy efficiency. For example, a 2007 study for Santee Cooper in South Carolina, prepared by GDS Associates, concluded that its 2017 peak loads could be reduced by approximately 10 percent and its energy sales could be reduced by up to 8.8 percent through implementation of well-designed and aggressive energy efficiency programs.[3] A 2008 study by the American Council for an Energy-Efficient Economy, Summit Blue Consulting and ICF Consulting, found that potential economic energy savings of approximately 6-9 percent could be achieved in Virginia by 2015, with potential savings of 12-25 percent by 2025. The study similarly found that a mid-

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1 EKPC's announced start date for construction of Smith Unit #1 is 2011.

2 EKPC's April 21, 2009 Integrated Resource Planning filing ("EKPC 2009 IRP"), at page 5-19.

3 *Electric Energy Potential Study*, January 2008.

investment strategy could reduce the state's peak electric demands by about 8 percent in 2015 and 18 percent in 2025.[4]

- EKPC projects that the peak load and energy sales savings it will achieve from its current and new demand side programs will increase only through 2017 and then will slowly decrease in following years.[5] This is an unrealistic assumption that biases the analysis in favor of the addition of new supply side resources.

Before 2000, a heavy reliance on coal may not have presented a financial problem other than constituting a highly undiversified resource base. However, at this time in the electric industry, EKPC's current and projected heavy dependence on coal-fired generation is risky for both its member cooperatives and their retail customers for a number of reasons: the potential for higher fuel prices and coal supply disruptions; the potential for substantial carbon emission compliance costs; and the potential for the federal government to mandate further reductions in other non-greenhouse gas coal plant emissions such as SO_2, NO_x, mercury and small particulates.

Finding 2. EKPC is continuing its expensive generation expansion program in a period of great economic and financial uncertainty.

EKPC is proposing to spend an additional $766 million to build the proposed Smith Unit #1 CFB coal plant. As has been documented in *The Right Decision for Changing Times: How East Kentucky Power Cooperative Ratepayers Benefit from Canceling Plans for a New Coal Burning Power Plant in Clark County*¸ this capital investment program would be expected to strain EKPC's financial resources even in normal times.[6] However, EKPC is undertaking this investment program in a time of economic and financial crisis, as well as substantial uncertainty in costs associated with new coal investments. This commitment to significant capital investment arises just when economic conditions heighten the sensitivity of utility customers to rate increases.

The current economic recession represents a near term challenge for utilities, and exacerbates risks that EKPC 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."[7] 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."[8]

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

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4 *Energizing Virginia: Efficiency First.* Available at www.aceee.org.

5 EKPC 2009 IRP, at pages 5-8 and 8-50.

6 Prepared by Tom Sanzillo, Senior Associate, TR Rose Associates, Inc., New York, NY.

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

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

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."

At the same time that the economic recession strains utilities like EKPC, the financial crisis and ongoing credit crunch create uncertainty as to their ability to raise needed capital and what the costs of borrowing will be for the capital they need 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."

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.[9]

EKPC also may be forced to pay much higher costs to borrow capital from the market for its proposed investments in the proposed Smith Unit #1. 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 electric cooperatives that were developing the proposed Highwood Generating Station in Montana were reported to have had difficulty obtaining funding for their project.[10] The cooperatives have since announced that they will build a baseload natural gas-fired plant at the site instead of a coal plant.[11]

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9 Ibid, at pages 6-8.

10 "Funding questions linger as power plant breaks ground," Great Falls Tribune, October 19, 2008.

11 http://www.billingsgazette.net/articles/2009/02/02/news/state/20-highwood.txt.

Finding 3. A comprehensive system for federal regulation of carbon dioxide (CO_2) and other greenhouse gas emissions is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions. However, under its proposed resource plan, EKPC's annual CO_2 emissions will increase, not decrease, as a result of the addition of the three new coal units, Spurlock Unit #3, Spurlock Unit #4 and the proposed Smith Unit #1.

Corporate, government, and financial leaders anticipate imminent greenhouse gas regulation in the U.S., and that greenhouse gas emission restrictions will pose substantial challenges and create significant new costs for the owners of coal-fired power plants. For example, 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 (CO_2) into the air"[12]

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 (CO_2). 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.[13]

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 CO_2 legislation.[14]

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

Regulation of greenhouse gases is inevitable and will increase the cost of running power plants that emit CO_2, particularly those that are coal-fired due to the high carbon content of coal. There are two likely avenues for federal regulation of greenhouse gases. Congress could pass

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

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

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

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 also are pursuing plans for aggressive legislative action on climate change during this session. To date, the most substantive legislative proposal is the bill introduced by Congressmen Waxman and Markey that would mandate the following greenhouse gas reduction targets:

- 2012 – 97% of 2005 emission levels
- 2020 – 80% of 2005 emission levels
- 2030 – 58% of 2005 emission levels
- 2050 – 17% of 2005 emission levels

Figure 1, below, shows the emissions trajectories that would be mandated under the proposed Waxman-Markey legislation. These trajectories aim for emissions reductions of 83 percent from 2005 levels by 2050, similar to the plan recently announced by the Obama Administration.

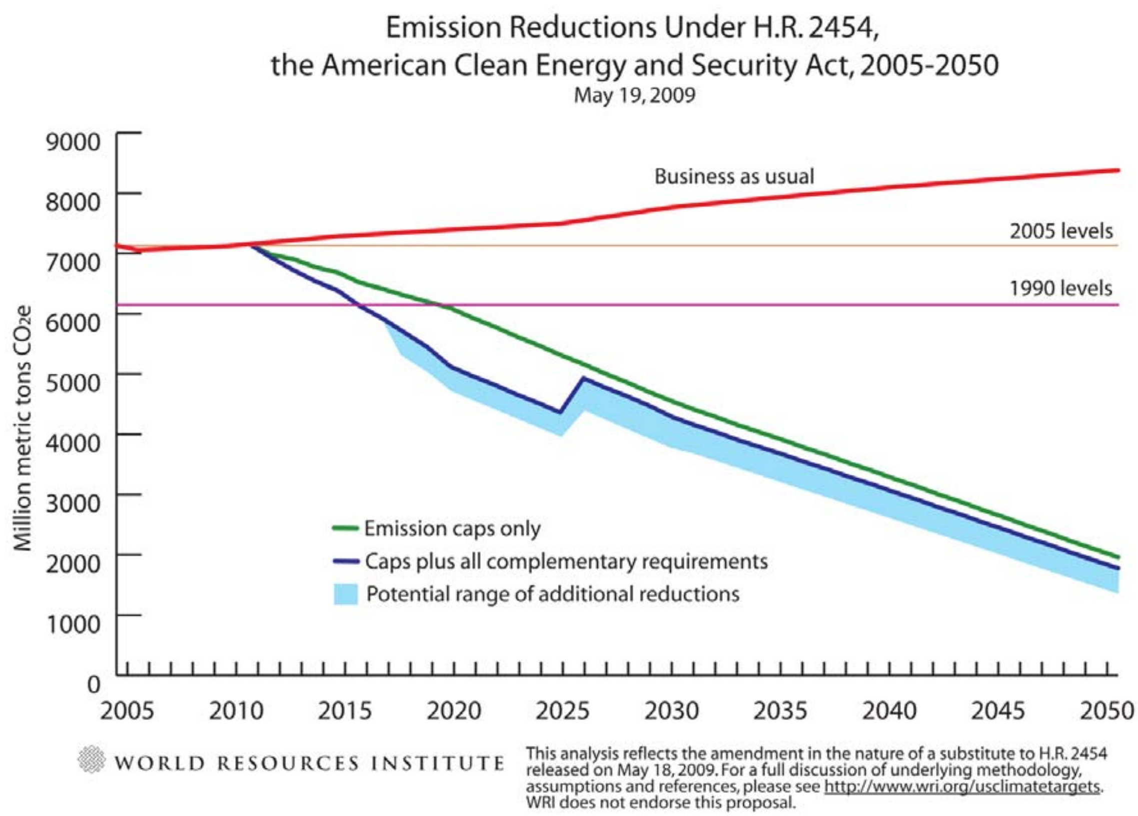

Figure 1. Emissions reductions that would be required under the Waxman-Market climate change legislation introduced in the current 111th U.S. Congress.

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.[15] The EPA has now circulated its draft finding, for public comment, that greenhouse gas emissions endanger public health and welfare.[16] 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.

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. This plan would require emissions reductions that approximate the steepest reductions shown in Figure 1. 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.[17] 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.

Unfortunately for EKPC's member cooperatives and their retail customers, the resource plan adopted by EKPC not only is inconsistent with these evolving federal climate change policies – it is contrary to these evolving policies because it will lead to higher, not lower, annual CO_2 emissions. By building its three new coal-fired power plants, EKPC will be locked into decades of high CO_2 emissions just at a time when those emissions will become costly. These costs would become the burden of ratepayers.

Figure 2, below, provides an illustrative example of EKPC's future CO_2 emissions with all three of its new coal-fired power plants and compares that trajectory to the emissions reductions that would be required under the Waxman-Markey legislation. EKPC's actual CO_2 emissions increased starting with the addition of the Spurlock Unit #3 unit in 2005 but decreased somewhat between 2007 and 2008. Figure 2 adds an expected 2.5 million tons of CO_2 equivalent emissions from Spurlock Unit #4 beginning in 2009 and from Smith Unit #1 in 2014, the plant's target in-service date in EKPC's 2009 IRP filing.

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15 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 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."

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

17 Edison Electric Institute, "EEI Global Climate Change Points of Agreement," January 14, 2009

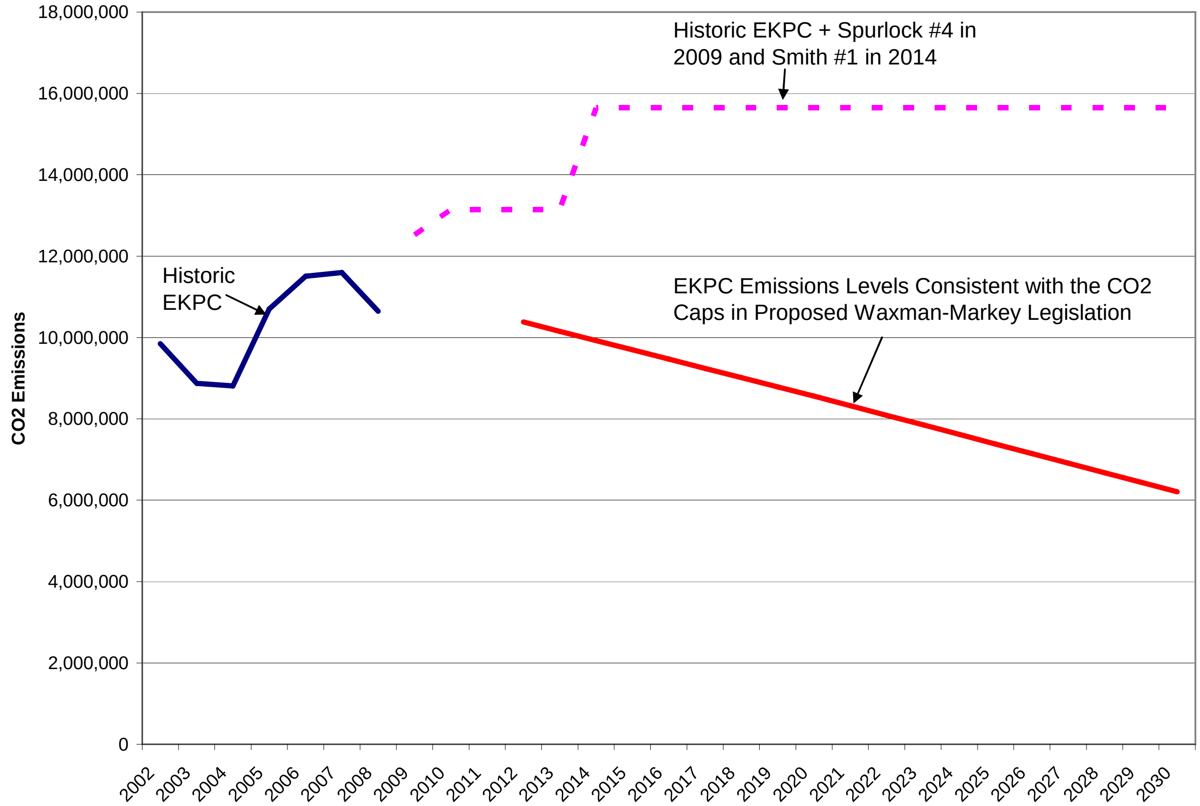

Figure 2. EKPC's Historic and Future CO_2 Emissions compared to the Emission Levels that Would Be Consistent with the National CO_2 Caps in the proposed Waxman-Markey Legislation.

As can be seen, EKPC's current resource plans will be inconsistent with national emissions trends under evolving federal climate change policies. For example, in 2023, EKPC's future CO_2 emissions could be some 7.8 million tons higher than emission levels consistent with the caps in the proposed Waxman-Markey legislation being considered in the U.S. Congress. This gap would continue to grow over time unless EKPC took very aggressive actions to reduce its CO_2 emissions.

As a result of its historic reliance on coal-fired generation, EKPC will have to significantly reduce its CO_2 emissions over the coming decades or else pay significant costs to procure emissions allowances. Adding another new coal-fired power plant with Smith Unit #1 units would certainly be a major step in the wrong direction. EKPC instead should be examining plans and options for reducing, not increasing, its greenhouse gas emissions by building the proposed Smith Unit #1 coal-fired power plant.

Finding 4: EKPC's new Spurlock Unit #3, Spurlock Unit # 4 and Smith Unit #1 coal units would each emit approximately 2.5 million tons of CO_2 each year. There currently is no commercially viable technology for capturing CO_2 emissions from these CFB coal plants.

Each of EKPC's new CFB coal plants can be expected to emit approximately 2.5 million tons of CO_2 equivalents each year for a likely 60 year operating life. That would mean that these units would emit an additional 450 million tons, in total, of CO_2 into the atmosphere if they are operated for 60 years unless some technological fix, or silver bullet, is developed to capture CO_2 emissions from coal plants like these units and permanently sequester the CO_2 in the ground.

However, there is currently no technology for economically reducing carbon emissions from a power plant that could be added once the timing and stringency of federal emissions limits are known. This is because unlike for other power plant air emissions like sulfur dioxide and oxides of nitrogen, there currently is no commercially demonstrated, economically viable method for the post-combustion removal of CO_2 from 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 CFB coal-fired power plants like the Spurlock Unit #3, Spurlock Unit #4, and Smith Unit #1 coal units. 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 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 Smith Unit #1 would be expected to be in the range of 10.4 cents to 11.7 cents per kilowatt hour. If shown to be technically and legally feasible, the costs of transporting and permanently sequestering the CO_2 in the ground would be in addition to these costs.

The proposed Waxman-Markey legislation would add a performance standard to the Clean Air Act for coal-fueled power plants that, like Smith Unit #1, have not received their required air permits. The legislation requires that electric generating units that are permitted between January 1, 2009 and December 31, 2019 (i.e. received a Clean Air Act preconstruction approval or permit) must achieve an emissions limit that is 50% below their annual CO_2 emissions.[18] They must achieve compliance four years after the EPA Administrator finds that certain measures of commercialization have been achieved, but no later than January 1, 2025. Electric generating units that are initially permitted after January 1, 2020 must achieve an emissions limit that is 65% below their annual CO_2 emissions. The EPA Administrator may revise the emissions standard downward after 2025 to reflect emissions limits achievable through the best system of emission reduction that EPA deems to have been adequately demonstrated.

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 plant in order to capture and, ultimately, sequester 90 percent or more of its CO_2 emissions. Because if carbon capture and sequestration technology is not added to these new coal plants, EKPC's member cooperatives and their retail customers instead would have to pay tens to hundreds of millions of dollars each year to buy allowances to cover the plants' CO_2 emissions.

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[18] American Clean Energy and Security Act, Amendment in the Nature of a Substitute, Title I, Subtitle B, Section 116 Performance Standards for Coal-Fueled Power Plants.

Finding 5. Ratepayers will face significant financial risk associated with the decision to lock in increasing carbon emissions for the coming decades at a time when those emissions will be costly.

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 account in such a long-lived investment.

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.[19]

> 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.[20]

Similarly, as Standard and Poor’s has explained, it is reasonable to expect that:

> 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.[21]

Numerous modeling analyses of federal policy proposals for mandatory greenhouse gas reductions in the U.S are available (e.g. 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

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

20 Ibid.

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

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 or absence of a "safety valve" price.

Based on a number of factors, including our assessment of the results of these modeling analyses, Synapse has developed a set of CO_2 price forecasts that we believe provides a reasonable range of possible future CO_2 allowance values. These forecasts are presented in Figure 3:

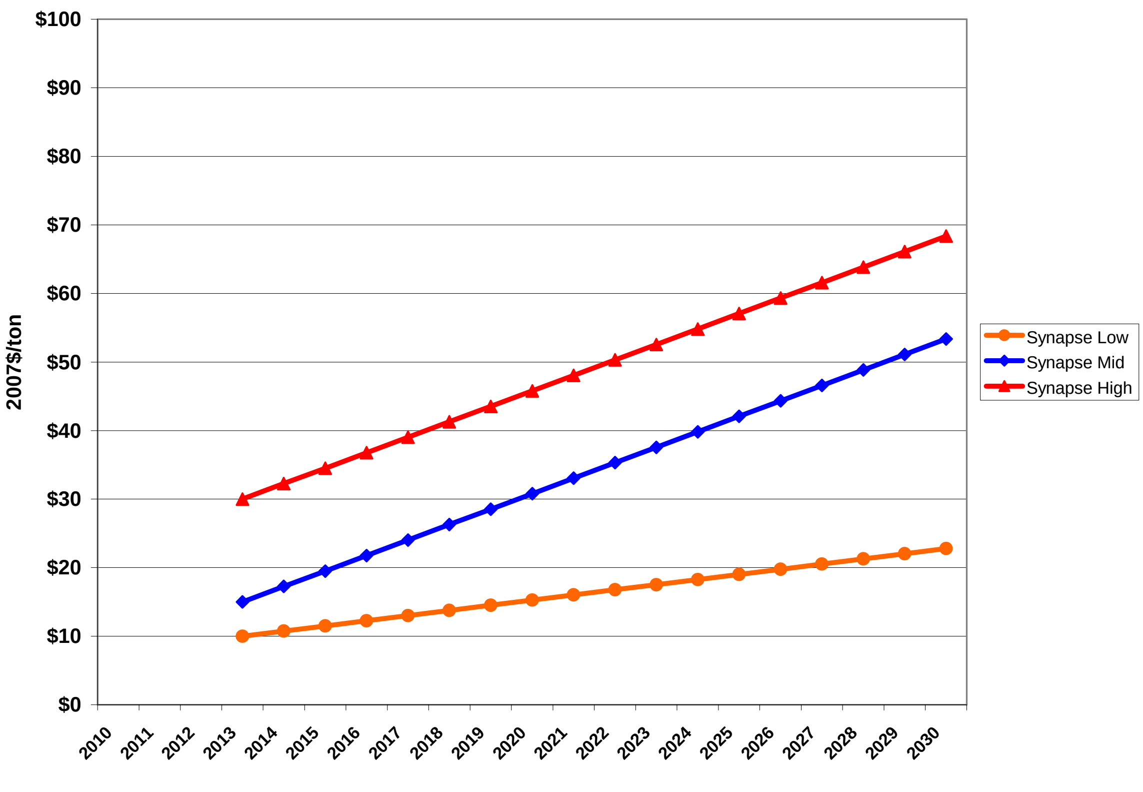

Figure 3. Synapse 2008 CO_2 allowance price forecasts.

The 2008 Synapse CO_2 Price Forecasts shown in Figure 5 are all in 2007 dollars. The Synapse Low CO_2 Price Forecast starts at $10/ton in 2013 and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars. The 2008 Synapse High CO_2 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, also in 2007 dollars. Synapse also has prepared a Mid CO_2 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 CO_2 price forecast is $30/ton, in 2007 dollars.

Synapse first developed a set of CO_2 price forecasts in the spring of 2006. However, significant developments since that time led Synapse to re-examine and raise those CO_2 price forecasts this past summer to ensure that they reflect an appropriate level of financial risk associated with greenhouse gas emissions.[22] 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 under consideration in the 110th U.S. Congress 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 CO_2 emissions allowance prices in electricity resource planning and selection for the period 2013 to 2030 (as discussed below).

EKPC's 2009 IRP filing says that it has imputed a cost of $40 per ton for carbon emissions based on previous legislation proposed under the Bingaman and Lieberman-Warner Bills (in the 110th Congress). It is unclear, however, whether this $40 per ton figure is per ton of CO_2 or per ton of carbon emitted. If the $40 figure is for each ton of carbon emitted, this only represents a cost of approximately $10 to $11 per ton of CO_2. This would be an extremely low CO_2 cost compared to the allowance prices projected by a wide range of studies from such objective sources as the U.S. EPA and Department of Energy, Duke University and the Massachusetts Institute of Technology.

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 proposed Smith Unit #1, EKPC's member cooperatives and their retail customers instead would have to pay tens to hundreds of millions of dollars each year to buy allowances to cover the plants' CO_2 emissions – allowances that would be auctioned as part of the cap-and-trade program. The annual costs for purchasing the allowances for the approximate 2.5 million tons of CO_2 that the proposed Smith CFB plant would emit each year are shown in Figure 4, below. The annual costs in this Figure reflect the Synapse High, Mid and Low CO_2 price trajectories shown in Figure 3, above. Although Figure 4 only goes through 2030, EKPC's customers would have to pay these increasing annual costs right through the end of the operating lives of its coal plants, or until the capability for carbon capture and sequestration is added to the facility.

[22] 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

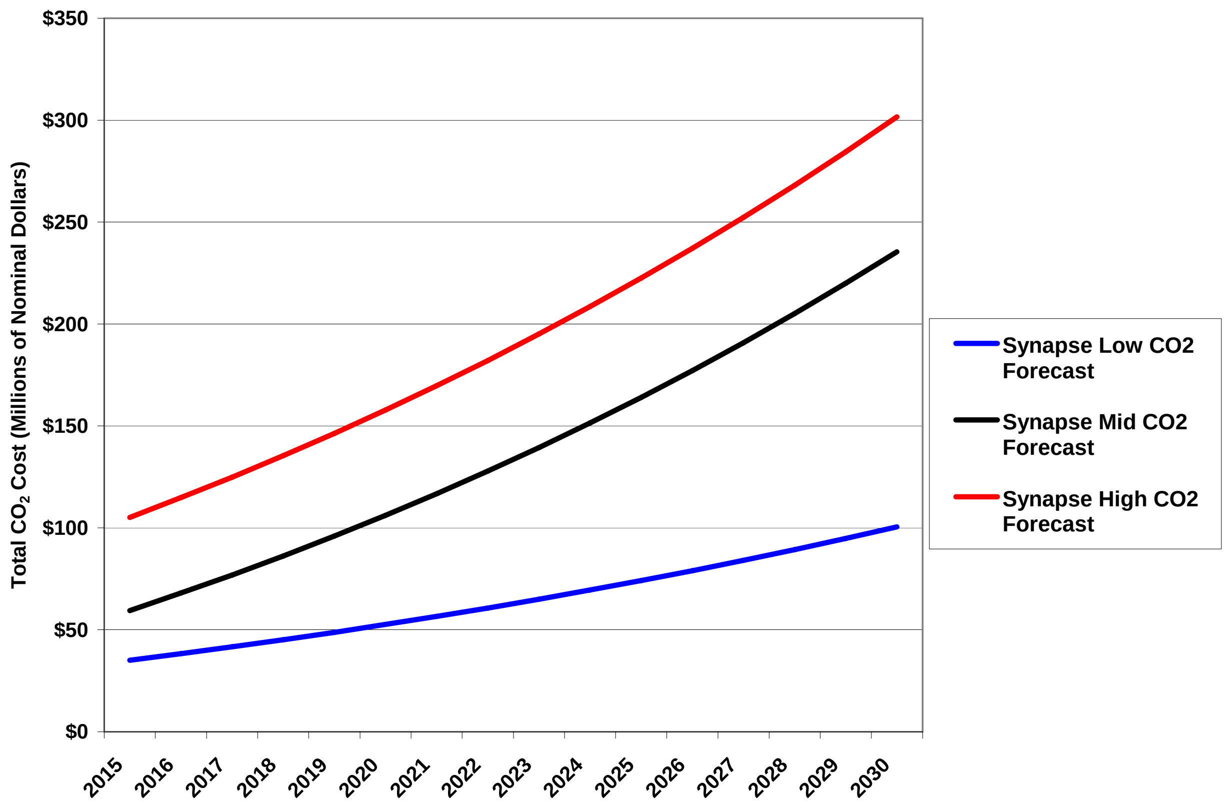

Figure 4. Proposed Smith CFB Coal Plant annual CO_2 costs (millions of nominal dollars).

Thus, if it builds the proposed Smith CFB coal-fired power plant, EKPC's customers may have to pay between $35 million and $105 million for the CO_2 emitted by that plant in 2015, and these costs could rise to between $100 million and $300 million in 2030. Of course, EKPC's member cooperatives and their retail customers also likely would have to pay for some of the CO_2 emitted by its other coal and gas-fired power plants.

In fact, it was noted earlier in this report that EKPC's overall CO_2 emissions in 2023 may be some 7.8 million tons above the levels that would be consistent with the national caps in the proposed Waxman-Markey legislation. Purchasing emissions allowances for these 7.8 million tons of CO_2 would cost EKPC's member cooperatives and their ratepayers between $203 and $609 million, in the year 2023 alone. Similar expenditures could be expected in other years, as well.

Finding 6. The construction cost of proposed Smith Unit #1 could be higher than EKPC's currently estimated $766 million cost.

EKPC has said that the estimated construction cost for the proposed Smith Unit #1 is $766 million. However, 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 5, below, which shows the increases between the actual construction costs of the recently completed Spurlock Unit #3 and Spurlock Unit #4 CFB plants and the proposed Smith Unit #1.[23]

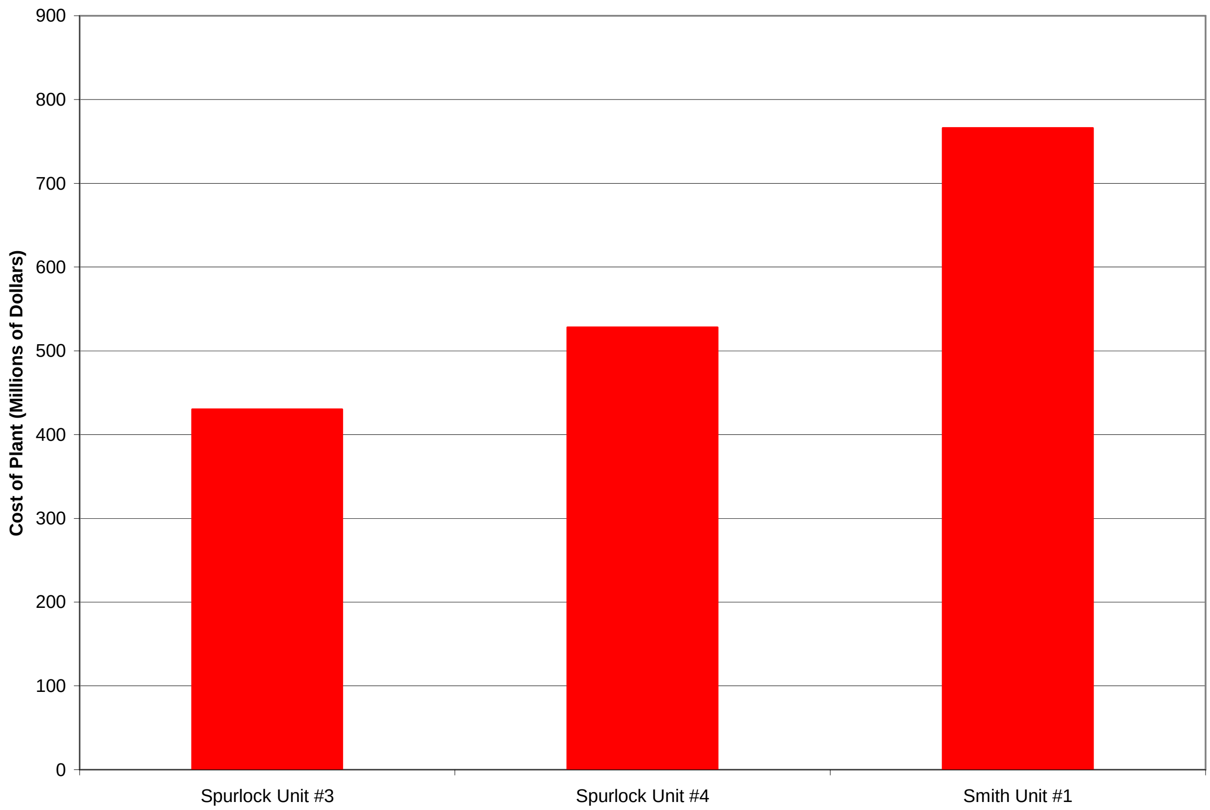

Figure 5. Construction Costs of EKPC's Three 278 MW Coal-Fired Power Plants.

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. The estimated cost of AMP-Ohio's proposed Meigs County Coal Plant nearly tripled in the three years between October 2005 and October 2008.

There are, of course, no guarantees that the construction costs of new coal plants such as Smith Unit #1 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

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23 Some of this cost difference is explained by the plan for better controls on Smith Unit #1for criteria pollutants.

2008, nearly three years into construction. This shows that even plants that are under construction are not immune to cost increases.

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.[24]

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.[25] 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.

Finding 7. 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 90 coal power plant cancellations, delays and rejections by state regulatory commissions.

EKPC 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 90 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.

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 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.[26]

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

25 Ibid, at page 18.

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

In April of 2008, the Virginia State Corporation Commission rejected a proposed coal plant citing uncertainties of costs, technology, and unknown federal mandates.[27] 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."[28]

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."[29] 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."[30]

Then, in November 2008, the Public Service Commission of Wisconsin rejected the proposed 300 MW (net) Nelson E. Dewey CFB coal-fired power plant. 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.[31] 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."[32]

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:

- 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

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

28 Id, at page 5.

29 Id, at page 10.

30 Id, at page 10.

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

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

> because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it.[33]

- 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."[34]

- 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:

> 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.[35]
>
> 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.[36]

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:

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

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

35 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.

36 http://www.aeci.org/NR20080303.aspx.

- 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 East 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 gasses are commercially feasible, which it believes is not likely before the end of the next decade.[37]

- 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.[38]

- 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, New Mexico and Nebraska, voted to shift its focus from building 2 or 3 proposed coal plants to natural gas, renewable energy and efficiency.[39]

- In mid-May 2009, four Electric Membership Corporations withdrew from the proposed Plant Washington coal project in Georgia, citing high costs and concerns about the uncertainties surrounding federal climate legislation.

- 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.[40] 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."[41] 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

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

38 http://www.alliantenergy.com/Newsroom/RecentPressReleases/023120.

39 "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.

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

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

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….

With regard to CO_2 legislation, while the Commission and the Company certainly anticipated that CO_2 regulation would be in place over the life of this Project and incorporated CO_2 compliance costs into its evaluation, there seems to be an emerging momentum to implement CO_2 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 CO_2 legislation and how it will affect the Project economics. CO_2 costs, as the Company has always made clear, are an important factor in the Project economics, and while the possible implementation of CO_2 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.[42]

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.

[42] Ibid, at pages 6-8.