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December 2, 2013

Via Personal Delivery

Mr. Jeff Derouen, Executive Director
Case No. 2013-00259
Kentucky Public Service Commission 211
Sower Blvd.
Frankfort, KY 40601

Re: Case No. 2013-00259 Exhibits to Direct Testimony of Tyler Comings Inadvertently Left Off of Filing (Public Version)

Dear Mr. Derouen,

Enclosed please find exhibits 9, 10, and 11 to the Direct Testimony of Tyler Comings, which were inadvertently left off of the filing of the public version of the testimony, filed on November 27, 2013 in the above-referenced matter via personal delivery. By copy of this letter, all parties listed on the Certificate of Service have been served via e-mail. Please place this document on file.

Sincerely,

Kristin A. Henry

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Testimony of Anthony S. "Tony" Campbell
President & CEO
East Kentucky Power Cooperative

November 14, 2013

SUMMARY

EKPC is a generation and transmission cooperative based in Winchester, KY. Our mission is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC. Nationwide, not for profit electric cooperatives serve 42 million people in 47 states.

We do not believe Congress ever intended for the Clean Air Act to regulate greenhouse gas emissions from power plants.

The proposed Section 111 regulations have already had a chilling impact on electricity generation in the U.S. When that proposed rule was issued, approximately 15 coal-fired power plants had received a PSD permit, but had not yet commenced construction. By the time the rule was withdrawn and re-proposed in 2013, most of those plants had been scrapped due to regulatory uncertainty, despite the exemption EPA included in the proposed rule.

In recent years electric utilities have faced a daunting array of environmental regulations on all fronts – air, water, and waste – that have contributed to widespread unit retirements. Coal-fired generation is essential to ensure energy diversity and to keep electricity prices low. Although natural gas prices are currently low, recent data from the United States Energy Information Administration ("EIA") shows that natural gas prices have increased by more than 50% since April 2012.

In addition to the realities and risks of rising natural gas prices, it is not feasible for the nation's existing coal-fired generating capacity to be transitioned to natural gas. Natural gas generation requires transportation from natural gas wells to power plants via an intricate network of interstate pipelines and compressor stations. These requirements raise infrastructure and national security concerns.

EKPC's greatest apprehension relates to regulations for existing sources. EKPC operates three baseload power plants fueled by coal and one plant operated by natural gas-fired combustion turbines. EKPC has invested almost $1 billion in retrofitting existing coal-fired power plants with modern air pollution control equipment. Further, EKPC spent another $1 billion to construct two of the cleanest coal units in the country. An existing source rule that requires CCS would leave EKPC, with no choice but to convert these units to natural gas, essentially wasting the extensive capital investments that have been made to lower pollutants from the coal-fired units.

EKPC is very worried about the supply of electricity to its rural cooperative members and its cost. There is a lack of technology that would allow EKPC to control GHG emissions, and a lack of demonstrated benefits to the environment. Most if not all coal-fired units will be forced to retire as a result of the regulation of GHG emissions, which would astronomically increase electricity rates and ultimately cause further job losses.

TESTIMONY OF ANTHONY S. "TONY" CAMPBELL
PRESIDENT & CHIEF EXECUTIVE OFFICER
EAST KENTUCKY POWER COOPERATIVE

BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

REGARDING

EPA'S PROPOSED GREENHOUSE GAS STANDARDS FOR ELECTRIC POWER PLANTS

November 14, 2013

A. Introduction

Chairman Whitfield, Ranking Member Rush and members of the Subcommittee, thank you for the opportunity to appear before you today. My name is Anthony S. "Tony" Campbell. I am the President and CEO of East Kentucky Power Cooperative ("EKPC"), and I have served in that position since 2009. I have previously served as CEO of Citizens Electric Cooperative in Missouri, and my career has also included positions at Corn Belt Energy and Soyland Power Cooperative, both in Illinois. I have a Bachelor's degree in Electrical Engineering from Southern Illinois University and a Master's degree in Business Administration from the University of Illinois.

Nationwide, not for profit electric cooperatives serve 42 million people in 47 states. While about 12 percent of the nation's meters are members of a rural electric cooperative, those co-ops own and maintain 42 percent of the nation's electric distribution lines, covering three quarters of the nation's landmass. Electric cooperatives employ about 70,000 people nationwide.

EKPC is a generation and transmission cooperative based in Winchester, Ky. Our mission is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC. EKPC generates electricity at three baseload power plants fueled by coal and one peaking plant fueled by natural gas. More than 90 percent of the power we generate is fueled by coal. EKPC's total generating capacity is about 3,000 megawatts, and that power is delivered over a network of high-voltage transmission lines totaling about 2,800 miles. EKPC employs about 700 people.

More than 1 million Kentucky residents and businesses in 87 counties depend on the power we generate. Our 16 owner-member cooperatives serve mainly rural areas in the Eastern and Central two-thirds of Kentucky. EKPC and its member cooperatives exist only to serve their members. Our electric cooperatives serve some of the most remote parts of Kentucky. The terrain in this region varies from rolling farmland in Central Kentucky to mountains in the eastern portion. On average, our cooperatives have about 9 consumers per mile of power line, while investor-owned utilities average 37 consumers per mile and municipal utilities average 48 consumers. We also serve some of the neediest Kentuckians. The household income of Kentucky cooperative members is 7.4 percent below the state average, and 22 percent below the national average.

B. Use of the Clean Air Act to Regulate Greenhouse Gases from Electric Utility Units

Congress never intended for the Clean Air Act to regulate greenhouse gas emissions ("GHG") from power plants. This fact is illustrated by EPA's attempts to promulgate GHG new source performance standards ("NSPS") under Section 111. The Administration's proposed GHG NSPS, first issued in April 2012, demonstrated unequivocally that the Administration seeks to end new coal generation through regulation. In that proposal EPA chose not to establish a separate standard for coal-fired units; instead, it lumped coal units together with natural-gas fired units into a new NSPS subcategory, and established a GHG emission limit that only some natural gas combined cycle units can achieve. These proposed Section 111 regulations have already had a chilling impact on electricity generation in the U.S. When that proposed rule was issued, approximately 15 coal-fired power plants had received a PSD permit but had not yet commenced construction. By the time the rule was withdrawn and re-proposed in 2013, most of those plants had been scrapped due to regulatory uncertainty, despite the exemption EPA included in the proposed rule. The impact of the proposed GHG NSPS on already permitted new coal plants was fully realized when EPA did not finalize the proposed GHG NSPS rule within a year after proposing it, and instead, re-proposed the rule in September without any exemption for transitional sources. EPA recognized in the preamble to the rule that there are only three new coal units under development that would not include carbon capture and sequestration ("CCS"), the proposed Wolverine project in Michigan, the Washington County project in Georgia, and the Holcomb project in Kansas.

Just last month the Supreme Court agreed to hear a challenge to EPA's regulations requiring major sources to obtain permits for GHG emissions along with traditional pollutants. The specific issue for which the Court granted certiorari is "whether the Agency's regulation of GHGs from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources." This case, *Utility Air Regulatory Group v. EPA*, tests EPA's authority to use the Endangerment Finding and the determination that GHGs from new motor vehicles must be regulated to protect public health and welfare as the basis to require PSD permits for new major sources of GHGs and major modifications to existing major sources of GHGs. Although this appeal will likely not directly address the regulations EPA is developing under Section 111 of the Clean Air Act, the real possibility that EPA's regulation of GHG emissions under the PSD permitting program may be struck down by the Supreme Court underscores the importance of Congressional guidance in this area.

While the current low price of natural gas has contributed to the decline in coal-fired electricity generation and the resurgence of natural gas-fired units, EPA's new regulations are an equally important factor in this trend. In recent years electric utilities have faced a daunting array of environmental regulations on all fronts – air, water, and waste – that have contributed to widespread unit retirements. According to the American Coalition for Clean Coal Electricity, EPA's rules have contributed to the closure of some 300 existing coal-fired units in 33 states.

Coal-fired generation is essential to ensure energy diversity and to keep electricity prices low. Although natural gas prices are currently low, recent data from the United States Energy Information Administration ("EIA") shows that natural gas prices have increased by more than 50% since April 2012. EIA's Annual Energy Outlook for 2013 projects that natural gas prices for the electric power sector will continue to increase by about 3.7% each year until 2040, and that total electricity demand will increase by 28% by 2040.[1] These estimates underscore the need for a diverse fuel mix that includes coal to meet these energy demands.

In addition to the realities and risks of rising natural gas prices, it is simply not feasible for the nation's entire existing coal-fired generating capacity to be transitioned to natural gas. Natural gas generation requires transportation from natural gas wells to power plants via an intricate network of interstate pipelines and compressor stations that allow the gas to be constantly pressurized. These requirements raise not only infrastructure concerns but also safety and national security concerns. If a key compressor station were to fail or be targeted in a terrorist attack, the nation's electric grid would be placed in jeopardy. When these natural gas supply requirements are contrasted with coal which is plentiful in supply, can be stockpiled at a 30-45 day supply, and can be transported via several different methods without the use of interstate pipelines, it makes no sense to require wholesale conversions from coal-fired generation to natural gas, particularly in areas of the country that are rich in coal resources and are not located in close proximity to natural gas wells.

Further regulations limiting GHG emissions from fossil fuel electric generating units are unnecessary and unreasonable. Coal-fired power plants in the U.S. contribute only approximately 4% to global GHG emissions.[2] The U.S. power fleet has already reduced CO_2 emissions by 16% below 2005 levels, with CO_2 from coal-fired power plants reduced by almost 25%.[3] These reductions are a result of the utility sector's shift to natural gas generation. EPA should allow coal-fired power plants to continue to make these reductions in a reasonable manner and in response to market pressures, instead of by regulatory fiat. Furthermore, the regulations at issue will not have a meaningful impact on global climate change. The minimal impact that these regulations will have on the environment further underscores the need for all GHG regulations to be economically achievable. Currently, EPA is developing GHG regulations for new and existing power plants without adequate input from coal states. None of EPA's listening sessions are located in Kentucky or any other coal state. Congressional action is necessary to keep EPA from regulating all coal-fired electricity generation out of existence.

C. The Whitfield-Manchin Discussion Draft Bill

EKPC supports the bipartisan Whitfield-Manchin discussion draft bill as common-sense legislation that provides important guidelines and parameters for EPA to follow in developing GHG regulations for new and existing power plants without causing irreparable harm to the U.S. economy. The Whitfield-Manchin discussion draft is different from many of the other bills and

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[1] EIA, *Annual Energy Outlook 2013*, April 2013, http://www.eia.gov/forecasts/aeo/.

EPA *Greenhouse Gas Reporting Program Data*, available at http://epa.gov/ghgreporting/ghgdata/reported/powerplants.html and Ecofys, *World GHG Emissions Flow Chart 2010*, available at http://www.ecofys.com/files/files/asn-ecofys-2013-world-ghg-emissions-flow-chart-2010.pdf.

[3] EIA, *Monthly Energy Review*, October 2013.

legislative riders that have been introduced in recent years, in that it does not seek to strip EPA entirely of its authority to regulate GHGs under the Clean Air Act. It narrowly responds to only one regulatory initiative by EPA – EPA's proposed regulation of GHG emissions from power plants under Section 111 of the Clean Air Act. This bipartisan bill is badly needed to ensure EPA does not promulgate a rule that jeopardizes the country's energy future, puts electricity reliability at risk, and severely harms the economy.

Although EPA's re-proposed GHG NSPS rule purportedly addressed many of the concerns raised in comments to the 2012 proposal, there are still many troubling aspects of the rule that require Congressional action. First, the proposed rule assumes that no new traditional coal-fired units will be built in the future and considers only IGCC and synfuel units in the rule's Best System of Emission Reduction (BSER) analysis for new coal-based unit CO_2 limits. Second, the proposed rule eliminated the 30-year compliance option that would have allowed utilities time to phase in use of carbon capture and storage (CCS). Instead, at least partial CCS is required to be implemented in new coal-fired power plants if new coal units are to achieve the BSER CO_2 limits. EPA identifies CCS projects that are currently being developed as evidence that CCS technology has been adequately demonstrated. However, none of the U.S. projects involve traditional coal units. Three of those projects are IGCC facilities that can more readily sequester CO_2 than conventional coal-fired power plants, and one project is a demonstration project at the Boundary Dam power station in Saskatchewan, Canada. In addition, EPA points to the Great Plains Synfuels project and a pilot CCS project that was operated at American Electric Power's Mountaineer Station in 2009 but subsequently cancelled, as examples of projects that have successfully implemented CCS. None of the generation projects are complete or currently operational and the synfuels project should not be used as a comparison for the electric generation industry.

All of the four CCS projects identified by EPA as currently under development[4] have received government funding. The Kemper IGCC project, which received a $270 million federal grant and $412 million in federal tax credits, recently announced that it will miss its May 2014 completion deadline. Delays at the Kemper IGCC project have contributed to an almost $5 billion cost that is almost double the original estimated cost of around $2.8 billion.[5] In addition, the Boundary Dam project recently announced a $115 million cost overrun despite receiving $240 million in funding from the Canadian government.[6] All of the four projects plan to sell captured CO_2 for enhanced oil recovery. EPA has not considered the taxpayer-funded portion of these project costs and does not appear to have accounted for cost overruns in its BSER analysis.

Any GHG emissions limit under Section 111 must reflect "the application of the best system of emission reduction which ... the Administrator determines has been adequately demonstrated." EPA has not presented any real evidence that CCS is adequately demonstrated. EKPC supports

[4] EPA identified Southern Company's Kemper County Energy Facility, SaskPower's Boundary Dam CCS Project, Summit Power Group's Texas Clean Energy Project (recipient of a $450 million federal grant), and Hydrogen Energy California, LLC's proposed IGCC facility (recipient of a $408 million federal grant).

[5] Associated Press, *Kemper County power project cost approaches $5 billion with latest rise* (updated Oct. 29, 2013 at 10:19 pm), http://blog.gulflive.com/mississippi-press-business/2013/10/kemper_county_power_project_co.html.

[6] Bruce Johnstone, *SaskPower CEO says ICCS project $115M over budget*, Regina Leader-Post (Oct. 18, 2013), http://www.leaderpost.com/business/energy/SaskPower+says+ICCS+project+115M+over+budget/9055206/story.html.

the language in the draft bill that would prevent EPA from imposing any GHG emission standard on new coal-fired units until such limit has been achieved by representative coal-fired units for at least a year, because EPA's determination that CCS has been adequately demonstrated does not reflect reality.

EKPC's greatest concern relates to regulations for existing sources. As stated earlier, EKPC operates three baseload power plants fueled by coal and one plant operated by natural gas-fired combustion turbines. Pursuant to a consent decree with EPA, EKPC has invested almost $1 billion in retrofitting existing coal-fired power plants with modern air pollution control equipment. Further, EKPC spent another $1 billion to construct two of the cleanest coal units in the country. An existing source rule that requires CCS would leave EKPC with no choice but to convert these units to natural gas, essentially wasting the extensive capital investments that have been made to lower pollutants from the coal-fired units. This would result because there is no demonstrated technology that would be able to control GHG emissions. In addition, EKPC has already expended all of its investment capital on pollution controls under the consent decree and has no additional funds to invest in new, expensive technologies such as CCS. The costs associated with such a transition would represent a devastating and unfair impact to our rural members who have already paid for pollution control upgrades to EKPC's existing generating units, only to deal with much higher electricity rates. Higher electricity rates would further harm Kentucky's economy, where coal production has decreased by 64% since 2000. Recent coal mining employment figures released by the Kentucky Energy and Environment Cabinet show only an estimated 12,342 individuals employed in Kentucky coal mines – the lowest level recorded since 1927 when the Commonwealth began keeping mining employment statistics.[7] With higher rates, manufacturing jobs would also disappear, further compounding the impact to the economy from the loss of mining jobs. These dire figures demonstrate that Congressional action is sorely needed to ensure that coal-fired generation can continue in states like Kentucky.

These concerns extend to Governor Beshear's Kentucky Climate Action Plan which proposes significant GHG emissions reductions from the electric generating sector beginning in 2020. Reductions at this level will result in the shutdown of EKPC's coal units for which hundreds of millions dollars have been spent on pollution controls to ensure that the units could comply with EPA's many new environmental regulations. EKPC, instead, favors an approach like the one that the Whitfield-Manchin discussion draft bill contemplates, which we believe will foster more flexible, creative approaches to reducing GHGs from new and existing sources.

Even if we ignore the economic devastation that will result from an adverse existing source rule, Congressional action is also necessary to prevent Section 111(d) from being used to regulate GHG emissions from existing power plants. It is EKPC's view that the discussion draft bill does not go far enough, since the bill seems to assume that Section 111(d) is an appropriate vehicle for regulating GHG emissions from existing stationary sources. The discussion draft bill requires only that Congress set an effective date for any standard of performance for existing sources under Section 111(d) and that such rules or guidelines may not take effect unless the Administrator has submitted to Congress a report containing:

[7] Kentucky Energy and Environment Cabinet, *Kentucky Quarterly Coal Report*, Q2 2013, http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q2-2013).pdf

(1) the text of such rule or guidelines;
(2) the economic impacts of such rule or guidelines, including potential effects on economic growth, competitiveness and jobs, and on electricity ratepayers; and
(3) the amount of GHG emissions that such rule or guidelines are projected to reduce as compared to overall GHG emissions.

While this may have the result of delaying indefinitely any regulations that EPA may promulgate under Section 111(d), EKPC supports a more permanent solution that clarifies that Section 111(d) cannot be used to regulate GHG emissions from existing power plants. Regardless of whether the utility sector may eventually succeed in challenging these regulations, Congress should put an end to the regulatory uncertainty surrounding existing power plants and clarify that Section 111(d) and, in fact, Section 111 as a whole, is not the appropriate mechanism for regulating GHG emissions from electric generating units.

C. Conclusion

EKPC appreciates the work of this Committee and the opportunity to present our views on EPA's regulation of GHGs from power plants. To summarize, EKPC's main concern is for our rural cooperative members. There is a lack of technology that would allow EKPC to control GHG emissions, and a lack of demonstrated benefits to the environment. Most if not all coal-fired units will be forced to retire as a result of the regulation of GHG emissions, which would astronomically increase electricity rates and ultimately cause further job losses. EKPC believes the transportation and national security concerns presented by natural gas pipelines and compressor stations, as well as the upward trend in natural gas prices make conversion to a gas-fired utility fleet much too risky for this country's energy security. I would like to reaffirm EKPC's support for the Whitfield-Manchin discussion draft bill. Congressional action is sorely needed to end the regulatory uncertainty surrounding the electric power sector and put the country back on a path toward full economic recovery.

2013 Carbon Dioxide Price Forecast

November 1, 2013

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Contents

1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy that sets a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

The Synapse 2013 CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. The current forecast updates Synapse's 2012 CO_2 price forecast, published in October 2012.[1] Our 2013 forecast incorporates new data that have become available since 2012, in order to provide useful CO_2 price estimates for utility resource planning purposes.

1.1. Key Assumptions

Synapse's 2013 CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast include:

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer-term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;

[1] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

- A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
- A series of executive actions taken by the President that spur demand for Congressional action;
- A Supreme Court decision that permits nuisance lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
- Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2 emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

To develop the 2013 CO_2 price forecast, Synapse reviewed several key developments that have occurred over the past year. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Updates to the U.S. carbon price used to assess the climate benefit of federal rulemakings;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the first allowance auctions under California's AB 32 Cap-and-Trade program;
- The results of a multi-year Energy Modeling Forum (EMF) research effort on the costs of U.S. emissions abatement from nine integrated assessment modeling teams; and
- Carbon price forecasts from the most recent IRP efforts of 28 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in sections 3 through 9, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

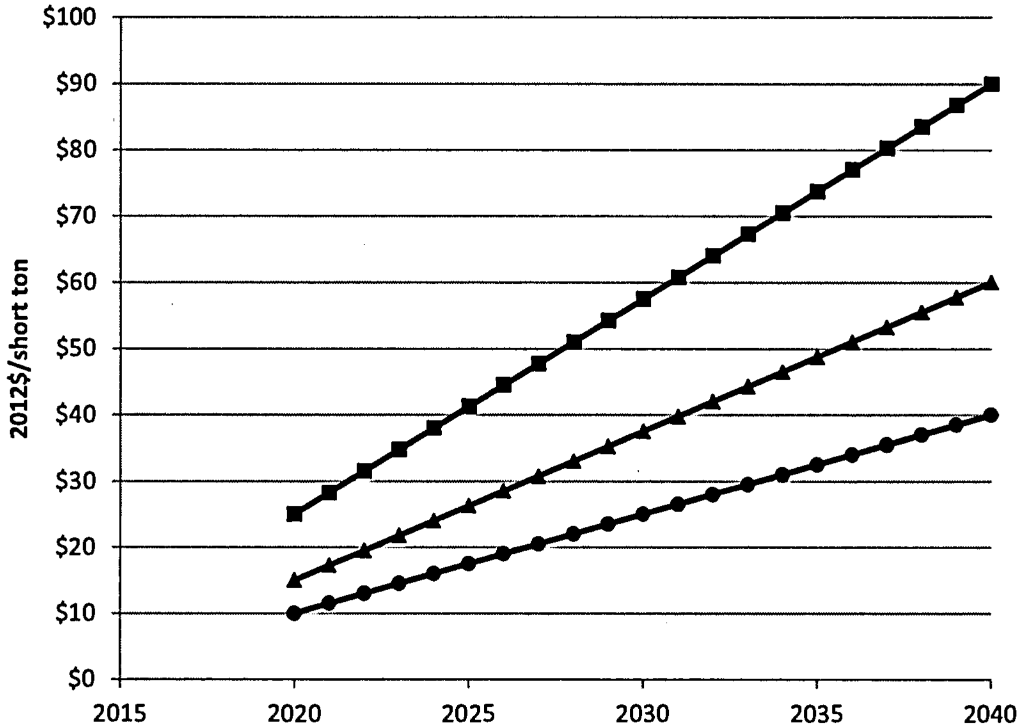
Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES- 1: Synapse 2013 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term "carbon price" or "CO_2 price": each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the "price of carbon"—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called "cap and trade"): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[4] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the "cap" in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called "internalizing an externality": The external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast's RGGI and California's Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no "cap"). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

[4] Whether or not allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency's (EPA's) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve": all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is almost achieved, and then asks: what would it cost to reduce emissions by one more unit to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information. McKinsey & Company has been a consistent producer of this type of analysis, an example being their 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.*

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change from the emission of one additional unit of pollutant. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is estimated as the social cost of carbon.

4. Federal Climate Action is Increasingly Likely

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[5] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[6] While this report is focused on electric sector CO_2 policies, similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[7,8]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lower cost. While state and regional policies combined with federal regulatory actions appear to be more likely than a federal cap-and-trade policy in the near term, according to a WRI analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[9]

[5] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[6] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[7] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[8] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

[9] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[10] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards on September 20, 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[11]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[12,13]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g. cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[14] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of

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[10] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[11] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[12] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[13] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[14] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[15]

End-use energy efficiency may be an important part of a comprehensive compliance strategy in a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states would be required to submit SIPs to the EPA by June 2016.

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at $7.53 per ton of CO_2 avoided.[16]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometime rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

[15] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[16] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review CSAPR. Even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard.
- *Coal Combustion Residuals (CCR) Disposal Rule:* On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by May 22, 2014.[17] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[18]

Other regulations which may raise costs for carbon-intensive resources include Regional Haze rules and cooling water rules under the Clean Water Act.

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[17] See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

[18] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in the 111th Congress: the American Clean Energy and Security Act of 2009, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in that session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[19] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill proposed a carbon fee of $20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

We expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. In contrast, federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures may be successful in achieving near-term targets of 17 percent below 2005 levels by 2020, but according to a WRI analysis are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[20] A broader approach will be increasingly attractive in order to meet these goals at lower costs, and our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

[19] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[20] See WRI's analysis of these scenarios in their 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

5. STATE AND REGIONAL CLIMATE POLICIES

Since the October 2012 release of our 2012 CO_2 price forecasts, there have been significant updates to the two existing regional and state cap-and-trade programs, the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[21]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. RGGI recently marked five years of successful CO_2 allowance auctions, with Auction 21 resulting in a clearing price of $2.67 per ton.[22] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[23]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation. Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[24]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

California's Cap-and Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's

[21] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[22] RGGI Auction 21 results available at: http://www.rggi.org/market/co2_auctions/results/Auction-21

[23] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

[24] Environment Northeast. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[25,26] On August 16, 2013, the California Air Resources Board held its fourth quarterly allowance auction, resulting in a clearing price of $11.11 per ton.[27] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

6. Assessment of Carbon Price for Federal Rulemaking

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[28] updated values were released in 2013.[29] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[30]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values--$11, $36, $55, and $101 per ton of CO_2 in 2013, rising over time— represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[31,32,33,34] While

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[25] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[26] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[27] CARB 2013b. "CARB Quarterly Auction 4, August 2013: Summary Results Report." August 21, 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/august-2013/results.pdf.

[28] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[29] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[30] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[31] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[32] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to twelve times larger than the Working Group's central estimate.

subject to significant uncertainty, this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[35, 36] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[37] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. Recent CO_2 Price Forecasts from the Research Community

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies in a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a

[33] Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10.

[34] Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7.

[35] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[36] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37

[37] Brad Blumer (2013). "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[38,39]

Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other more structural characteristics of the models. One question asked by this study that is of particular relevance to users of the Synapse CO_2 price forecast is: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between \$10 per tCO_2 and \$40 per tCO_2. In contrast, prices fell between \$20 per tCO_2 to \$80 per tCO_2 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

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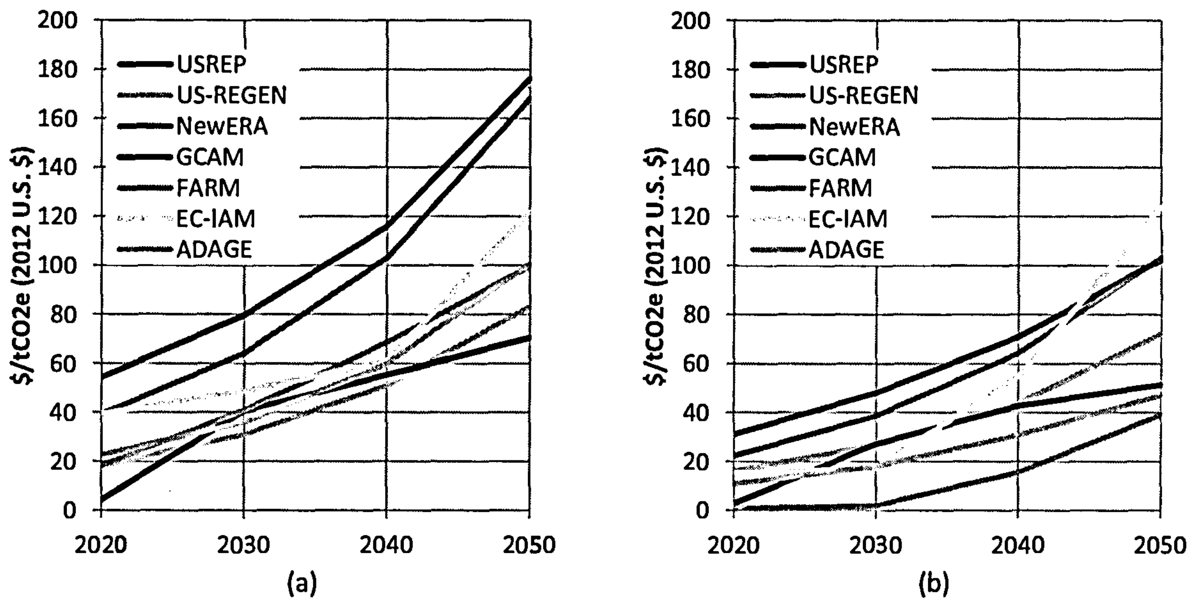
[38] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," (forthcoming). *The Energy Journal.*

[39] Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant. "Overview of EMF 24 Policy Scenarios," (forthcoming). *The Energy Journal.*

Figure 1: Allowance prices from EMF study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions) [35,36]



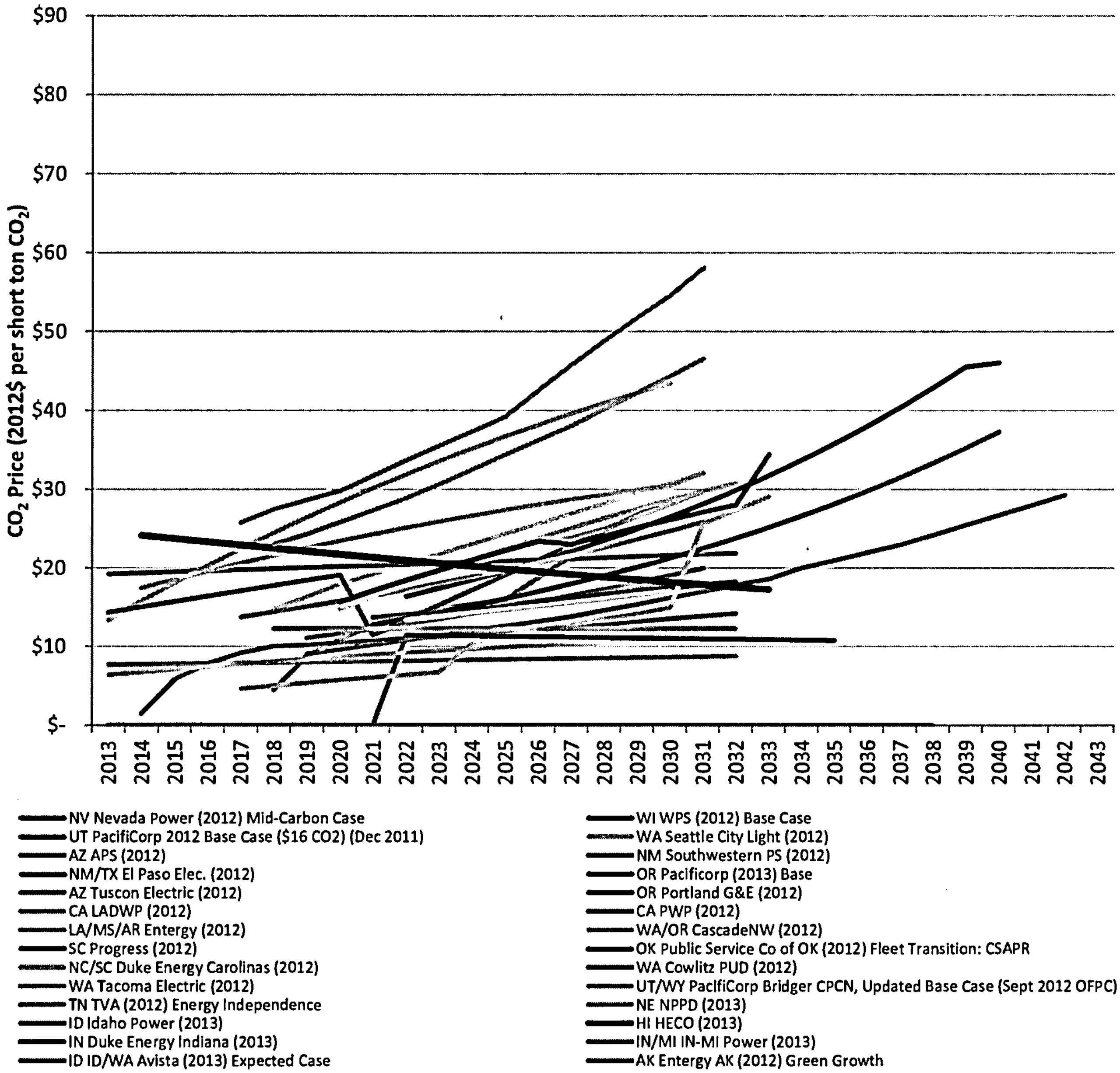
8. CO_2 PRICE FORECASTS IN UTILITY IRPS

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. Figure 2 summarizes the reference case values (often described as their "mid" or "central" values) of publicly available forecasts used by utilities in resource planning over the past two years.[40]

Despite ongoing obstacles to a federally legislated CO_2 price and challenges in Congress to addressing climate or energy policy in a meaningful way, many utilities are including an effective price for carbon in their planning. The majority of utility reference case carbon price forecasts start in the 2015-2020 timeframe, and rise gradually (in real terms) throughout the study period.

[40] Where a utility has released multiple IRP or IRP updates in the past two years, we have included only the most recent value. The IRPs shown here represent those publicly available by internet as of the October 2013.

Figure 2: Utility Reference Case Forecasts from 2012 and 2013



9. Overview of the Evidence for a Future CO_2 Price

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term.** The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed on September 20, 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent.** In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. SYNAPSE 2013 CO_2 PRICE FORECAST

Based on analyses of the sources described in sections 3 through 8 (above), and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure 3 and Table 1 show the Synapse forecasts over this period.

Figure 3: Synapse 2013 CO_2 Price Trajectories

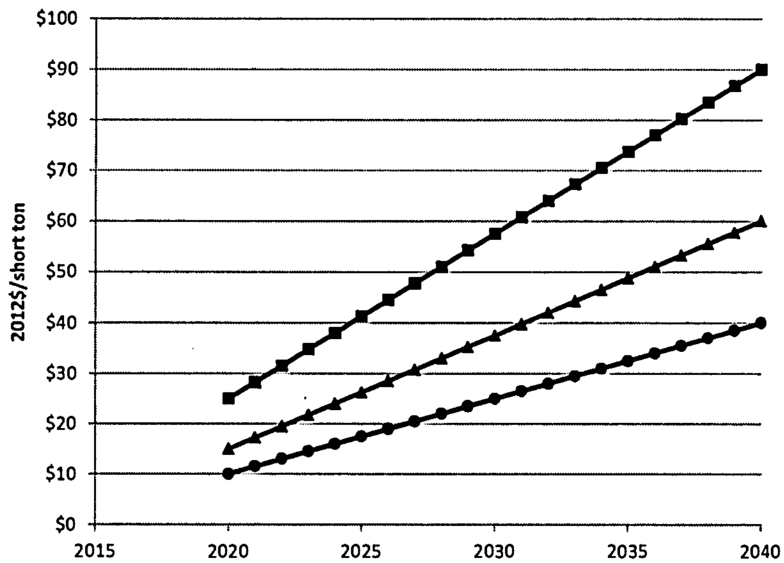


Table 1: Synapse 2013 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

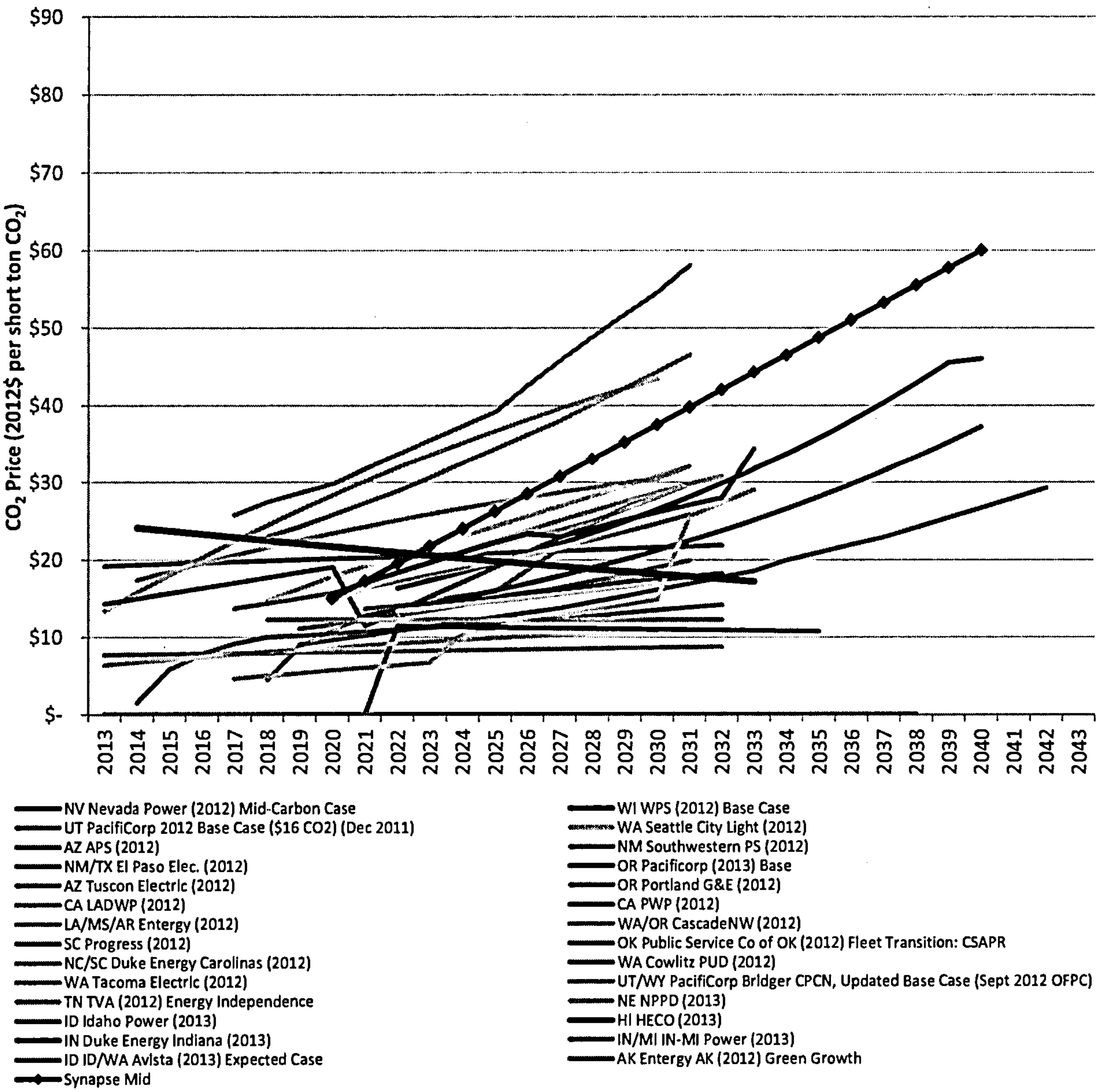
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more

aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 4, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 4: Synapse Mid Forecast Compared to Recent Utility Mid Case Forecasts



In Figure 5, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period. In Figure 6, the Synapse forecasts for 2020 are compared to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central values show less variation.

Figure 5: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

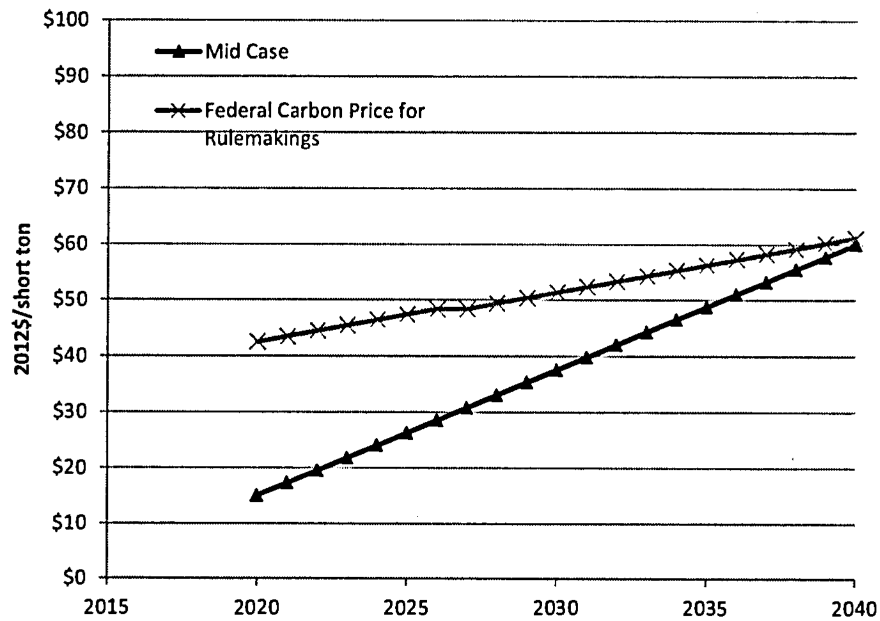
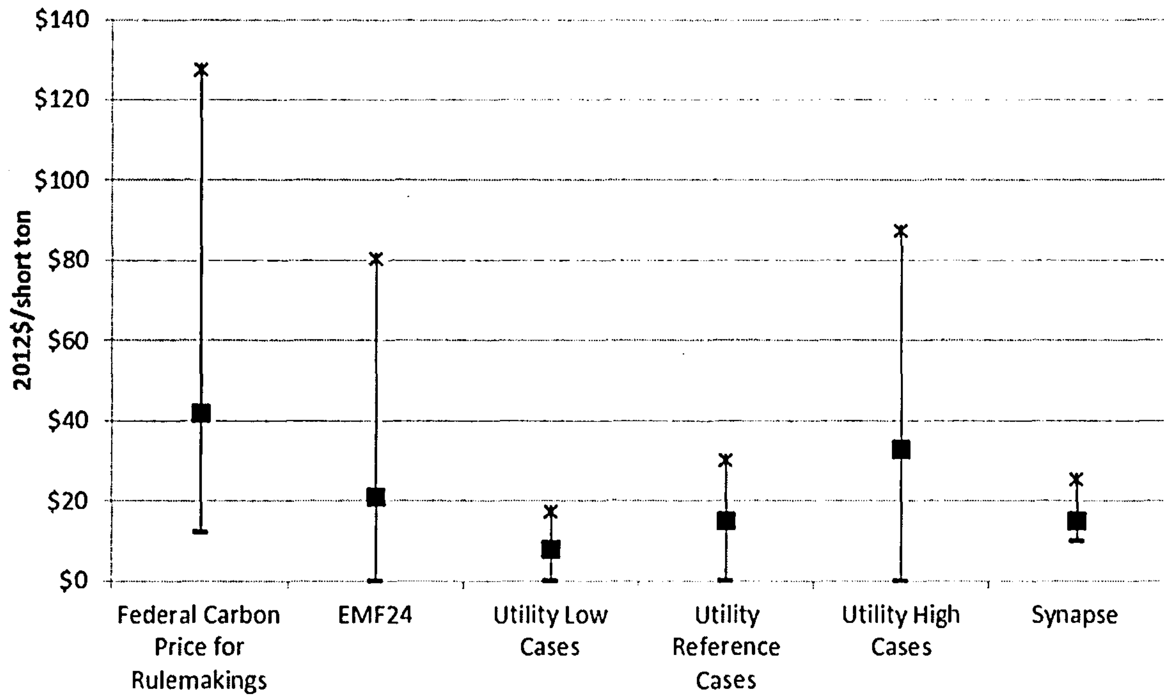


Figure 6: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



APPENDIX A: SYNAPSE FORECAST COMPARED TO UTILITY FORECASTS

Figure 7: Synapse CO_2 Price Forecast Compared to Recent Utility Low-case Forecasts

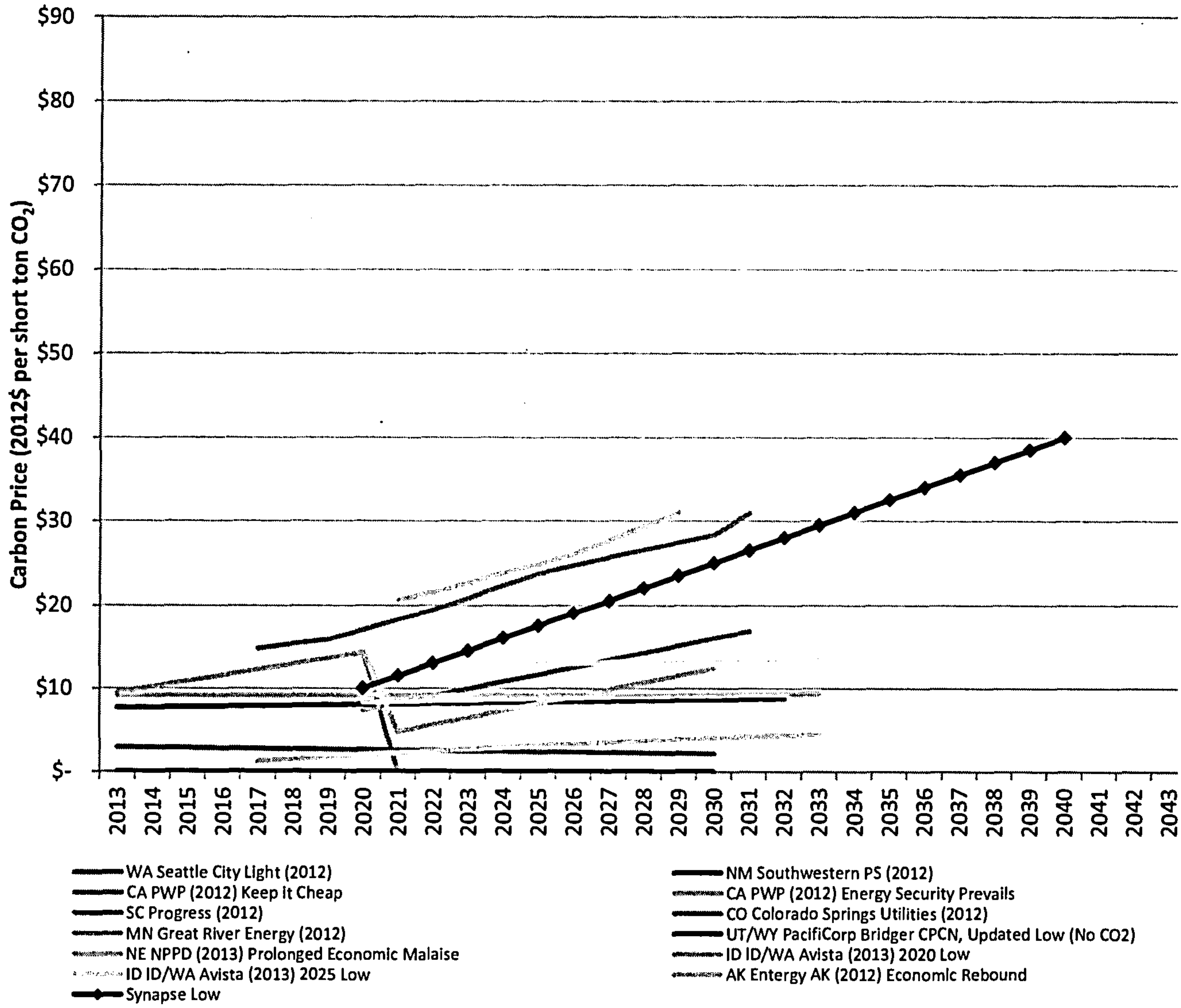
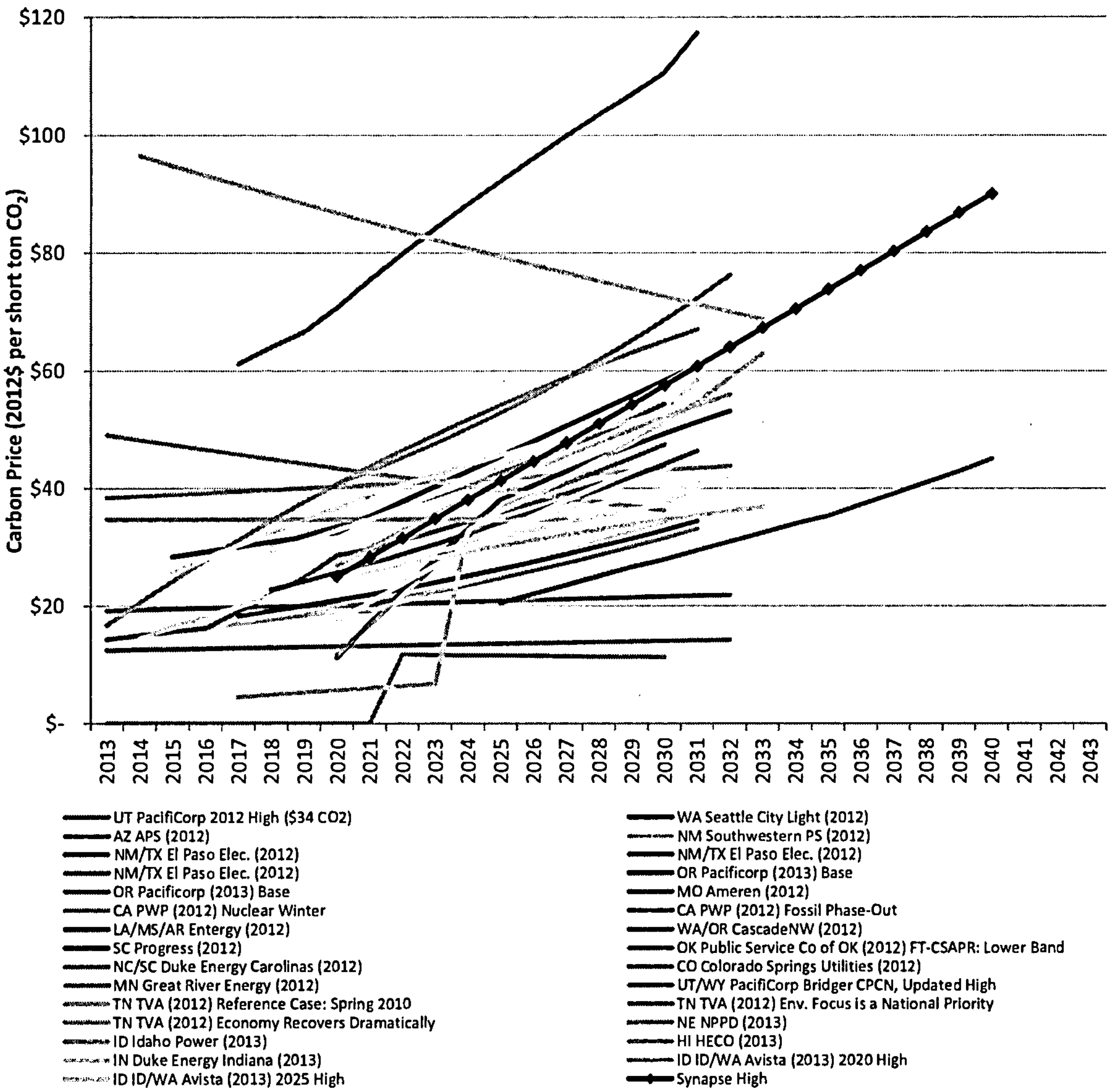


Figure 8: Synapse CO_2 Price Forecast Compared to Recent Utility High-case Forecasts



Business Wire
A Berkshire Hathaway Company

Fitch Affirms East Kentucky Power Cooperative's Sr. Secured Bonds at 'BBB'

October 29, 2012 11:41 AM Eastern Daylight Time

NEW YORK--(BUSINESS WIRE)--Fitch Ratings affirms the 'BBB' rating on the following East Kentucky Power Cooperative (EKPC) outstanding secured bonds:

--$25.9 million County of Mason, KY pollution control revenue bonds, series 1984B;

--$6.5 million Pulaski County, KY solid waste disposal revenue bonds, series 1993B.

In addition, Fitch affirms the rating of 'BBB' on EKPC's implied senior unsecured obligations. The rating takes into account $400.7 million of parity debt at Dec. 31, 2011.

The Rating Outlook is Stable.

SECURITY

The senior secured obligations are secured by a mortgage interest in substantially all of EKPC's tangible and certain of its intangible assets.

KEY RATING DRIVERS

GENERATION AND TRANSMISSION COOPERATIVE: EKPC supplies wholesale power to its 16 member-owner distribution cooperatives who serve predominantly rural territories in central and eastern Kentucky. The cooperative's generation fleet is geographically diverse; however, the vast majority of power is derived from the cooperative's coal-fired units.

SOLID UNDERLYING COOPERATIVE FUNDAMENTALS: EKPC supplies power to its members pursuant to long-term, take-or-pay contracts that extend through Jan. 1, 2051, and require members to purchase from EKPC nearly all of their power requirements to meet system needs. This contractual relationship, together with the diversity and financial wherewithal of the member distribution cooperatives are fundamental to the rating.

IMPROVING FINANCIAL PROFILE: EKPC's financial profile has stabilized in recent years following a series of operational challenges and financial distress during the period 2004-2006. A more defined and comprehensive strategic plan has been adopted by the new management team and board of directors, which appears to be on track and supports credit quality.

SUBJECT TO RATE REGULATION: The electric rates charged by EKPC and its members are regulated by the Kentucky Public Service Commission (KPSC), which could limit the cooperative's financial flexibility and may delay the timing or amount of necessary rate increases. Regulation by the KPSC to date has been largely supportive.

SUFFICIENT POWER SUPPLY RESOURCES: EKPC's current portfolio of power supply resources is generally sufficient to meet anticipated demand through 2018, obviating the need for significant construction activity or additional debt. The environmental compliance risks related to its coal-dominated portfolio are lessened by the presence of emissions control equipment at its most active units.

ACCEPTABLE FINANCIAL METRICS: Fitch-calculated financial metrics for 2011 include debt service coverage (DSC) of 1.25x and equity to capitalization of 10.2%, both of which are consistent with the rating category. Total debt to funds available for debt service (FADS) of 10.4x is weaker than comparable Fitch rated cooperatives but Fitch expects that EKPC's high leverage to moderate as equity builds up pursuant to the strategic plan.

WHAT COULD TRIGGER A RATING ACTION

EXECUTION OF STRATEGIC PLAN: Successful execution of the current strategic plan and achievement of the cooperative's financial objectives could trigger consideration for an upgrade.

RESTRICTIVE RATE REGULATION: Future regulatory decisions that prevent the cooperative from adequately recovering costs would likely result in downward pressure on the rating or Outlook.

CREDIT PROFILE

EKPC is a not-for-profit generation and transmission cooperative incorporated in 1941 and headquartered in Winchester, Kentucky. EKPC supplies wholesale energy, transmission and support services to its 16 member distribution cooperatives, who serve predominately rural territories throughout 87 counties in central and eastern Kentucky. In 2011, the EKPC membership provided retail electric service to more than 521,000 residences, farms and businesses. The rates and services provided by EKPC are regulated by the KPSC.

Adequate Power Supply Resources

EKPC owns and operates a portfolio of generating units with capacity totaling 2,929 MW. Nearly 64.3% of EKPC's generating capacity is coal-fired, but nine relatively new natural-gas fired units provide valuable peaking capacity, as well as fuel diversity. Additional capacity and energy supply to meet member load demand is derived from ownership of 15.2 MW of renewable landfill gas projects, its allocation of Southeastern Power Administration hydro-electric capacity, and modest amounts of purchased power. EKPC's existing resources are largely sufficient to meet forecasted demand over the near term. The cooperative has no plans for significant new construction prior to 2015.

EKPC has issued a request for proposals (RFP) to obtain up to 300 MW of generation resources with an online date between October 2015 and 2017. This capacity is planned to replace 200 MW of capacity from the Dale station as the unit approaches the end of its useful life in 2016, and potentially replace 100 MW of capacity from the Cooper unit 1. Power purchase agreements and facility ownership options are under consideration. Fitch does not evaluate the merits of owning versus purchasing power, but considers the costs and benefits to the entity of both scenarios.

Troubled Operating and Financial History

Over the past decade, EKPC has faced a series of circumstances which have challenged both the operational and financial performance of the cooperative. Beginning in 2004, alleged violations of environmental requirements, a forced outage at the cooperative's Spurlock Unit 1 generating facility and the determination that considerable new generating capacity would be required to meet anticipated load growth all contributed to higher operating expenses and capital requirements. At the same time, management's decision to forego timely rate increases produced negative net margins and severely strained cash flow. These events ultimately led to a period of financial distress.

Improved Performance Under New Leadership

In recent years a new leadership team has been assembled at the cooperative, which has worked to implement recommendations from a KPSC-ordered management audit, and draft a comprehensive strategic planning effort. Although the principal components of the strategic plan are still nascent, management's earlier initiatives have restored some stability to the cooperative's financial results and appear to have set the stage for continued improvement.

Fiscal 2011 results point to another year of stability and financial improvement, a result of KPSC's approved rate increase, healthier working capital, customer stability and fleet optimization. EKPC reported net margins of $55.8 million, an increase of 70% over the previous year. Fitch-calculated metrics for DSC and total debt to funds available for debt service were correspondingly stronger increasing to 1.25x and decreasing to 10.4x, respectively. EKPC reported a times interest earned ratio (TIER) of 1.48x, up from 1.28x in 2010.

Additional information is available at 'www.fitchratings.com'. The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

Applicable Criteria and Related Research:

--'Revenue-Supported Rating Criteria', dated June 20, 2011;

--'U.S. Public Power Rating Criteria', dated March 28, 2011.

For information on Build America Bonds, visit www.fitchratings.com/BABs.

Applicable Criteria and Related Research:

Revenue-Supported Rating Criteria

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=681015

U.S. Public Power Rating Criteria

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=665815

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