BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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In the Matter of Investigation of Integrated	)	**DOCKET NO. E-100**
Resource Planning in North Carolina - 2009	)	**SUB 124**

DIRECT TESTIMONY OF DAVID A. SCHLISSEL ON BEHALF OF ENVIRONMENTAL DEFENSE FUND, THE SIERRA CLUB, SOUTHERN ALLIANCE FOR CLEAN ENERGY AND THE SOUTHERN ENVIRONMENTAL LAW CENTER

PUBLIC VERSION

FEBRUARY 19, 2010

List of Exhibits

Exhibit DAS-1	Current Resume for David A. Schlissel
Exhibit DAS-2C	Duke Energy Carolinas' *The 2030 Vision*, dated June 4, 2009 [CONFIDENTIAL]
Exhibit DAS-3C	Duke Energy Carolinas' *Duke Energy Low-Carbon Strategy*, dated 8/25/09 [CONFIDENTIAL]
Exhibit DAS-4	*Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009
Exhibit DAS-5	*U.S. Natural Gas Supply: Then There Was Abundance*, American Gas Association, January 20, 2010
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PUBLIC VERSION

Q. What are your name, position and business address?

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc., 45 Horace Road, Belmont, MA 02478.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the General Staff of the Arkansas Public Service Commission, the U.S. Department of Justice, the Attorney General of the State of New York, cities and towns in Connecticut, New York and Virginia, state consumer advocates, and national and local environmental organizations.

I have testified before state regulatory commissions in Arizona, New Jersey, California, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan, Florida, North Dakota and Mississippi and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

PUBLIC VERSION

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy and the Southern Environmental Law Center.

Q. Have you testified previously before the North Carolina Utilities Commission?

A. Yes. I have testified before the North Carolina Utilities Commission in Dockets Nos. E-2, Sub 526; E-2, Sub 537; and E-7, Sub 790.

Q. What is the purpose of your testimony?

A. I have been asked to review the 2009 Integrated Resource Plans ("IRP") submitted by Duke Energy Carolinas ("Duke") and Progress Energy Carolinas ("Progress"). I was asked to focus on the following specific issues:

- The reasonableness of carbon dioxide ("CO_2") prices used in the IRPs.
- Projected carbon emissions.
- Planned retirements of existing coal units and opportunities for additional retirements.
- Natural gas-fired generation as an alternative to existing coal.
- The potential cost of compliance with environmental requirements.

This testimony presents the results of my review.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. Federal climate change regulation currently under consideration will require significant reductions in the nation's annual CO_2 emissions over the coming decades. Duke, however, projects that its annual CO_2

emissions will increase between 2010 and 2029 in each of the resource portfolios that it has presented in the Revised 2009 IRP in spite of its announced plan to retire approximately 1,600 to 1,700 MW of cycling coal units by 2020.

2. It is not surprising that Duke's annual CO_2 emissions are projected to increase between 2010 and 2029 because of the planned addition of the Cliffside Unit 6 baseload coal unit. The new Cliffside Unit 6, on its own, can be expected to emit approximately six million tons of CO_2 each year, or more than two million tons more CO_2 than was emitted in 2008 by all of the cycling coal units that Duke discusses retiring.

3. In order to actually reduce its annual CO_2 emissions over the coming decades, Duke will have to reduce its reliance on coal-fired generation by retiring even more coal-fired generating capacity than it has so far proposed to retire. Given that Duke already is planning to add new nuclear units to its resource mix, the alternatives for displacing additional coal units are building more natural gas-fired combined cycle units, adding more renewable resources and adding more energy efficiency than the Company now includes in its resource plans.

4. Although new natural-gas fired combined cycle units will emit some CO_2, the amounts they emit will be significantly less than a comparable amount of coal-fired capacity.

5. The Commission should not be concerned that Duke would become unreasonably dependent on natural gas if it added more natural gas-fired

combined cycle units to replace additional coal-fired generating capacity. New assessments show that there is far more natural gas available in the domestic United States than was projected even two years ago. This should enhance the value of using natural gas as a bridge fuel to a lower carbon future and should ameliorate future natural gas prices.

6. Duke and Progress should consider the potential costs of EPA regulation of coal combustion wastes in their IRP analyses.

7. The Base case CO_2 prices that Duke used in its 2009 IRP analyses were reasonable. However, given the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions, Duke should have looked at a wider range of scenarios than only $\pm$ 15 percent around that Base case set of CO_2 prices. .

8. The CO_2 prices used by Progress in its 2009 IRP analyses are compared to the range of CO_2 prices that Duke used in its 2009 IRP and to the CO_2 prices used in resource planning by Synapse Energy Economics, state commissions and other utilities.

Annual CO_2 Emissions

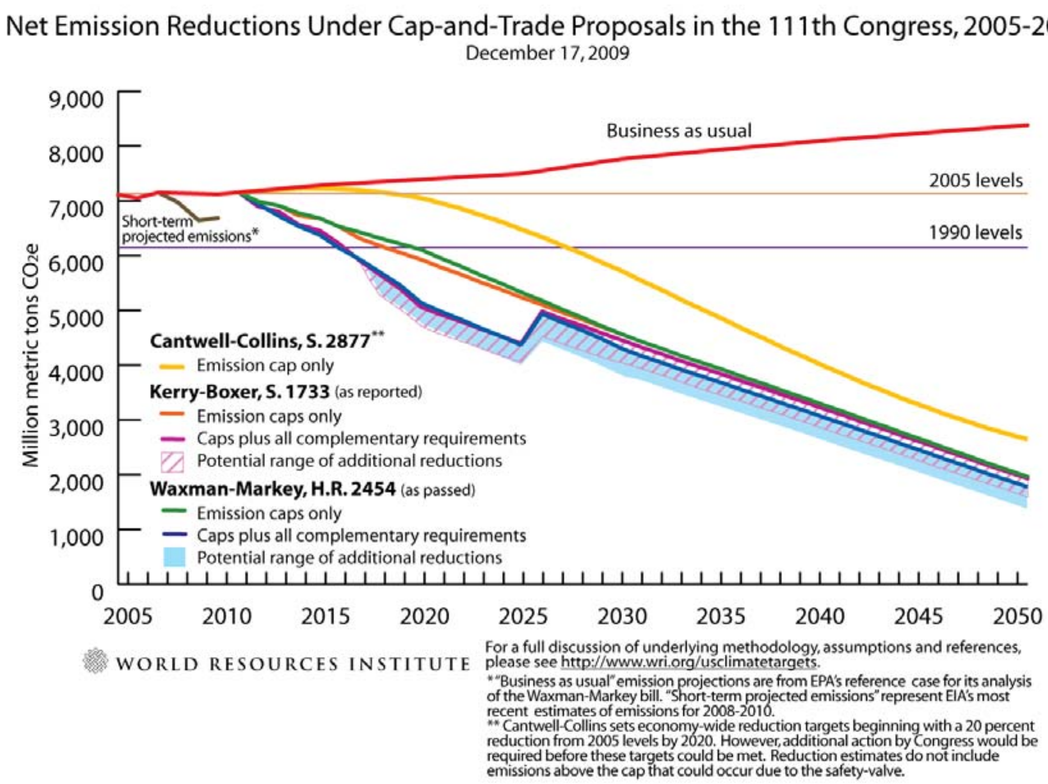
Q. What is the goal of the federal climate change legislation and policies that are being considered?

A. The general goal of most of the legislation and policies under consideration would be to reduce annual domestic U.S. CO_2 emissions by 60 percent to 80 percent from current levels by the middle of this century. It is generally believed by climate scientists that reductions of this magnitude might enable the world to avoid the most harmful effects of global climate change.

Q. What emissions reductions would be required under the bills that have been introduced in the current 111th U.S. Congress?

A. The emissions levels that would be mandated by some of these bills are shown in Figure 1 below:

Figure 1: Comparison of Legislative Climate Change Targets in the Current 111th U.S. Congress as of December 17, 2009



It is uncertain which, if any, of the specific climate change bills that have been introduced to date in the Congress will be adopted. Nevertheless, the general trend toward carbon regulation 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.

Q. Duke Energy, the parent of Duke, is a member of the U.S. Climate Action Partnership ("USCAP"). Are the emissions targets in the proposed legislation shown in Figure 1 above consistent with the emissions reduction goals recommended by the USCAP?

A. Yes. The United States Climate Action Partnership has recommended that national CO_2 emissions be reduced by 14 percent to 20 percent from 2005 levels by 2020, by 42 percent by 2030 and by 83 percent by 2050.[1] As shown in Table 1 below, the emissions targets in the Waxman-Markey legislation that has been passed by the U.S. House of Representatives are extremely similar to the goals promoted by the USCAP.

	USCAP	Waxman-Markey
2012	97%-102% of 2005 levels	3% below 2005 levels
2020	80%-86% of 2005 levels	17% below 2005 levels
2030	58% of 2005 levels	42% below 2005 levels
2050	20% of 2005 levels	83% below 2005 levels

Table 1: USCAP and Waxman-Markey CO_2 Emission Targets

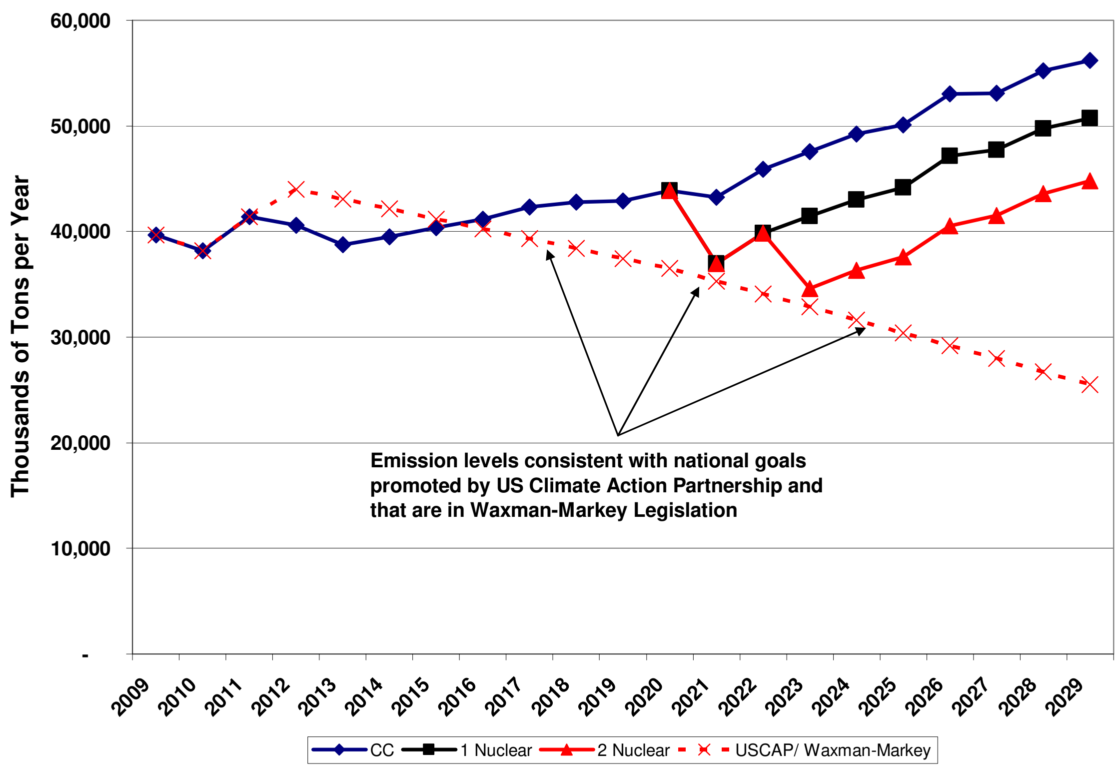
Q. What would Duke's annual CO_2 emissions be under its proposed IRP resource plan?

A. Duke discussed several modeling portfolios in its Revised 2009 IRP. These portfolios included no new nuclear units, one new nuclear unit and two new

[1] The United States Climate Action Partnership's website describes the group as follows. "USCAP is a group of businesses and leading environmental organizations that have come together to call on the federal government to quickly enact strong national legislation to require significant reductions of greenhouse gas emissions." www.us-cap.org USCAP materials refer to "the urgent need for a policy framework on climate change." www.us-cap.org.

nuclear units, respectively.[2] The annual CO_2 emissions for these resource portfolios are shown in Figure 2, below.[3]

Figure 2: Duke's Projected Future Annual CO_2 Emissions through 2030



The three solid lines in Figure 2 represent the CC (that is, no new nuclear units), the one new nuclear unit in 2021 and the two new nuclear units in 2021 and 2023 scenarios discussed by Duke in its 2009 IRP.

2 Duke Revised 2009 IRP, at pages 66 and 67.

3 Figure 2 shows the annual CO_2 emissions for the resource portfolios in which there were no new nuclear units, in which one new nuclear unit was added in 2021, and in which two new nuclear units were added in 2021 and 2023. Duke also modeled scenarios in which one new nuclear unit was added in 2018 and in which two new nuclear units were added in 2018 and 2019. Duke did not provide the annual CO_2 emissions for these other portfolios. However, it can be expected that their annual CO_2 emissions would be lower in the years 2018 through 2020 than the portfolios in which new nuclear units are added in 2021 and 2023 but would be approximately if not exactly the same in subsequent years.

Consequently, Duke's own projections show that its annual CO_2 emissions would increase in each of these three scenarios by between 13 percent and 42 percent (depending on the scenario) between 2009 and 2029 at the very time that legislation under consideration in Congress would be mandating reductions in emissions. In other words, Duke's CO_2 emissions would be going in the wrong direction, i.e. up, at a time when the mandated levels of emissions were being reduced.

Indeed, Duke's CO_2 emissions would be increasing during the very same years that its parent company Duke Energy is promoting, through the U.S. Climate Action Partnership, that national CO_2 emissions be significantly reduced.

Q. Do the CO_2 emissions trajectories shown in Figure 2 reflect the coal plant retirements that Duke discusses in the Revised 2009 IRP?

A. Yes. The CO_2 emissions trajectories shown in Figure 2 reflect the approximately 1,600 to 1,700 MW of coal plant retirements discussed at pages 40-43 of its January 11, 2010 Revised 2009 IRP.[4]

Q. Is it surprising that Duke is projecting that its annual CO_2 emissions will not go down between 2010 and 2029 given that it is proposing to retire more than 1,600 MW of existing coal capacity?

A. Not really. On its own, the proposed Cliffside Unit 6 coal unit will emit approximately six million tons of CO_2 each year, or more than two million tons more CO_2 per year than the total 2008 emissions of CO_2 from all of the coal units that Duke proposes to retire. In addition, Duke also is proposing to add between 5,700 MW and 6,700 MW of gas-fired capacity to its resource mix. Natural gas-fired units do emit CO_2 although they emit significantly less per MWh than coal-fired facilities.

Q. Is it possible that Duke will be required to actually reduce its CO_2 emissions between 2010 and 2030?

A. Yes. Duke's IRP modeling assumes that there will be legislation that will establish a cap-and-trade regime for CO_2 emissions allowances. Under a cap-and-trade scheme, Duke would not necessarily be required to reduce its emissions, but instead could purchase emissions allowances. It is possible, however, that, if Congress deadlocks on passing cap-and-trade legislation, the U.S. EPA will adopt regulations mandating actual reductions in CO_2 emissions under a command-and-control scheme. In those circumstances, Duke would have to actually reduce its CO_2 emissions rather than being able to simply purchase emissions allowances from other emitters.

Q. What actions will Duke have to take in order to reduce its annual CO_2 emissions?

A. Quite simply, Duke will have to reduce its reliance on coal-fired generation in order to significantly reduce its annual CO_2 emissions over the coming decades. To accomplish this, Duke will need to retire additional coal units beyond those already proposed for retirement. Given that the Company already is planning to include new nuclear units in its future resource mix, the alternatives for displacing additional coal units are building more natural gas-fired

[4] Duke Response to SELC Informal Data Request No. 13.

combined cycle facilities, adding more renewable resources and adding more energy efficiency than Duke now includes in its resource plans.

Q. Does the Company have any plans for actually reducing its CO_2 emissions?

A.

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5 Exhibit DAS-2C, at slide 6.
6 Exhibit DAS-3C, at page 16 – that is, the last slide

Q. You mentioned that one alternative for Duke to reduce its reliance on coal-fired generation is to build more natural gas-fired combined cycle facilities. Should the Commission be concerned that Duke would become unreasonably dependent on natural gas if it built more natural gas-fired combined cycle capacity to replace additional coal-fired generating capacity beyond the 1,600 MW that the Company currently is planning to retire by 2020?

A. No. First, it may not be necessary to replace coal-fired with gas-fired capacity on a MW for MW basis – in other words, some of the replacement capacity and energy may come from energy efficiency and renewable resources.

Second, Duke is projecting that gas-fired units will provide less than 0.4 percent of its needed energy from gas fired units in 2010 and only about 6 percent of its needed energy in 2029, even with the new combined cycle and combustion turbine capacity it is planning to add as part of its resource plan.[7] Thus, adding more natural gas-fired combined cycle capacity actually would help diversify Duke's current heavily coal-dependent generating mix.

Third, recent assessments suggest that there is far more natural gas available in the domestic U.S. This should enhance the value of using natural gas-fired generation as a bridge fuel to a lower carbon future and should ameliorate future natural gas prices.

In fact, the supplies of natural gas that have been identified in the past two years have been described as a structural change in the natural gas market. This structural change has two important impacts on future resource planning by companies such as Duke and Progress. First, as a result of the existing and expected supply glut, current and projected prices of natural gas have been reduced. At the same time, the dramatically increased supplies of natural gas that are being identified should be able to accommodate any increased demands from fuel switching as a result of federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early April of last year, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) a proposal to retire an existing gas-fired power plant and, in its place, to build a new coal-fired unit. Entergy explained that it no longer believes that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

> Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[8]

4. Recent Natural Gas Developments

> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000

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7 Revised 2009 IRP, at page 59

8 Exhibit (DAS-4). <u>*Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009</u>, at pages 6-8.

> through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
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> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. **The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….**
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> * * * *
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> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[9] [Emphasis added]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the American Gas Association and an independent organization of natural gas experts known as the Potential Gas Committee, the authority on gas supplies.

This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[10]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas and Pennsylvania and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas-demand.[11] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[12]

Finally, the American Gas Association ("AGA") has recently issued an assessment, "U.S. Natural Gas Supply: *Then There Was Abundance*," that detailed what the AGA term "the robust supply picture in the United States" and quelled

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[9] Id, at pages 17, 18 and 22.
[10] *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.
[11] Available at http://online.wsj.com/article/SB124104598912705 85.html.
[12] Id.

any doubts about the ability of natural gas to supply the country well into the next century."[13]

Q. What are Progress' projected annual CO_2 emissions under its proposed resource plan?

A. Unfortunately, Progress has not projected future CO_2 emissions as part of its IRP analyses.[14]

Potential Regulatory Compliance Costs

Q. In addition to carbon dioxide, are there other potential regulatory compliance issues and costs that electric utilities should take into account in their resource planning?

Yes. Electric utilities should include in resource planning the costs of other new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.

Q. What are coal combustion wastes?

A. Coal combustion wastes ("CCW"), also known as "coal ash" or "coal combustion products," consist of fly ash, bottom ash, boiler slag and flue gas desulfurization sludge and are typically disposed of in landfills and surface impoundments. CCW contains heavy metals such arsenic, nickel, cadmium,

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13 Exhibit DAS-6.
14 Progress Response to SELC Data Request No. 1, Item 1-8.

chromium, lead, manganese, selenium and thallium, as well as sulfates, chlorides, boron, polyaromatic hydrocarbons, phenols, polychlorinated biphenyls, cyanide, dioxins and furans. These substances can leach into water supplies when the waste comes into contact with water.

Q. Are coal combustion wastes regulated under North Carolina law?

A. It is my understanding that there are only limited requirements for disposal of CCW under North Carolina. For instance, North Carolina law exempts CCW surface impoundments and certain new CCW landfills from solid waste regulations. N.C.G.S. § 130A-295.4. At the same time, depending on the applicable permitting regulations, a liner may not be required for CCW landfills. N.C.G.S. § 130A-295.4(b); 15A N.C.A.C. 13B .0503. Moreover, liners are not required for CCW structural fill sites. 15A NCAC 02T .1201.

For slurry ponds permitted by the N.C. Division of Water Quality, groundwater monitoring and reporting is required, unless an exemption is granted.15A NCAC 02L .0110. In fact, the N.C. Division of Water Quality recently ordered Duke and Progress to begin testing the groundwater around their ash ponds in the state for contamination with toxic metals.[15]

In addition, Senate Bill 1004, enacted during the 2009 legislative session, placed coal ash impoundments under the Dam Safety Act and subjects dams that create coal ash ponds to direct inspection by the N.C. Department of Environment

[15] *State to require monitoring of ash ponds,* The Charlotte Observer, February 2, 2010.

and Natural Resources. Previously, electric utilities were only required to file reports with the Commission every five years.

Q. Is the EPA considering regulating coal combustion wastes?

A. Yes. EPA is currently considering proposed regulations to address coal combustion wastes.

Q. What has led to the EPA decision to consider regulating CCW?

A. A number of factors appear to have led the EPA to consider regulating CCW. First, a series of spills in late 2008 and early 2009, including the major spill of approximately one billion gallons of CCW at Tennessee Valley Authority's Kingston, TN coal plant in December 2008, drew the nation's attention to CCW storage.

At the same time, the EPA has found in a series of regulatory determinations that improper management of and disposal of combustion wastes from coal-fired power plants can and has resulted in surface water and groundwater contamination. EPA also has identified risks to human health and the environment from the disposal of CCW in landfills and surface impoundments.

For example, EPA's "Coal Combustion Waste Damage Case Assessment" dated July 9, 2007, recognized 24 proven cases of danger to human health or the environment and another 43 "potential" damage cases related to CCW. All but one of the 24 proven damage cases involved unlined disposal units.[16] EPA recently updated this list of damage cases to include coal ash spills at Martins Creek, PA, Gambrills, PA as well as the catastrophic spill of approximately one billion gallons of coal ash at TVA's Kingston, TN plant.[17]

The EPA also has identified gaps in state regulatory programs for disposal and management of CCW.[18]

Q. What are the possible forms that EPA regulation of CCW could take?

A. The EPA is evaluating whether to regulate CCW under the federal Resource Conservation and Recovery Act ("RCRA"). EPA is considering several options including 1) regulating CCW as hazardous waste under Subtitle C of RCRA, which would include a tracking system and federally enforceable permits; 2) regulating CCW as non-hazardous waste under Subtitle D of RCRA, which would include inducements for state solid waste programs and implementation of federal minimum regulations for landfills; 3) a hybrid approach, by which CCW would be considered a solid waste if certain conditions are met, but a hazardous waste if they are not; and 4) another hybrid approach whereby wet CCWs (in surface impoundments) would be regulated as hazardous wastes and dry CCWs (in landfills) would be regulated as non-hazardous wastes.

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16 U.S. EPA, Notice of Data Availability on the Disposal of Coal Combustion Wastes in Landfills and Surface Impoundments, 72 Fed. Reg. 49714, 49718-19 (Aug. 29, 2007).

17 75 Fed. Reg. 822 (Jan. 6, 2010).

18 72 Fed. Reg. 49716.

The EPA also recently announced that it may develop regulations setting financial responsibility requirements for power plants under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA," better known as "Superfund"), citing, among other things, the "significant cleanup costs that can be generated by this industry sector."[19]

Q. When is the EPA expected to issue a proposed regulation concerned CCW?

A. It is my understanding that the EPA is expected to issue a draft of its proposed regulation on CCW in the very near future, perhaps by the date of the hearings in this proceeding.

Q. Are there any estimates of the cost of complying with the anticipated EPA regulations concerning CCW?

A. The costs associated with the EPA's anticipated regulation of coal combustion wastes are uncertain and will depend on how the EPA classifies the wastes and plant specific factors (that is, wet versus dry storage, lined versus unlined, whether stored on the surface or not). Progress has stated the following in its December 1, 2009 *Plan to Retire 550 MWs of Coal Units Without SO2Controls*, that was filed in Docket E-2, Sub 960:

> EPA is currently considering re-characterizing the nature of and regulation of coal combustion products (bottom ash, fly ash and related materials, hereinafter CCPs) in response to TVA's Kingston Plant ash pond impoundment failure. Speculation is focusing on EPA's regulation of CCPs as a hazardous waste. A narrow usage exclusion may be possible where the finished product of CCP is fully encapsulated. Existing uses that involve land application or unconfined uses may be prohibited. If EPA

[19] 75 Fed. Reg. 816, 822 (Jan. 6, 2010).

> characterizes CCPs as a hazardous waste or otherwise increases the regulatory requirements applicable to CCPs, the handling, storage and disposal of this material will result in significantly increased costs of operation, and more sophisticated handling equipment and disposal requirements. Classification of power plant CCP operations as activities that produce hazardous wastes as defined by the Resource Conversion and Recovery Act (RCRA) would trigger a number of additional regulatory requirements as well as potential liability associated with closure of impoundments, leachate management and site remediation. Phase out of surface impoundments is under consideration by EPA.[20]

Q. What has the electric utility industry claimed regarding the cost impact of EPA regulation of coal combustion wastes?

A. Although the industry cost estimates may be exaggerated in order to dissuade the EPA from regulating CCW as hazardous waste, they do predict significant costs. For example, an October 30, 2009 letter to the Federal Office of Management and Budget from the Utility Solid Waste Activities Group[21] warned that:

> If [coal combustion wastes] were regulated as hazardous wastes, the economic impact on the utility industry would be enormous, resulting in power plant closures, increased electricity rates for consumers, corresponding power reliability concerns, and virtually eliminating all [CCW] beneficial uses.[22]

Testimony before Congress by a representative from EPRI similarly stated that:

> A national coal combustion products regulation will alter the technology and economics of coal-fired power plants. Some owners would decide to prematurely shut down rather than incur the costs of compliance, while others would convert their ash

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[20] At pages 7 and 8.
[21] The Utility Solid Waste Activities Group is described as an informal consortium of 80 utility operating companies, the Edison Electric Institute and others.
[22] At page 2.

handling and disposal systems and continue to operate in the post-regulation market.[23]

Q, What have been the costs of cleaning up CCW spills?

A. The cost to clean up the damage from the December 2008 release from Tennessee's Kingston plant has been estimated to range from $933 million to $1.2 billion.[24]

Q. How could Duke and Progress reflect this issue in their IRP analyses given all of the uncertainty associated with the EPA's possible regulation of coal combustion wastes?

A. The traditional way to address uncertainty in resource planning is to identify a wide range of the potential costs for key input assumptions.[25] Thus, Duke and Progress could identify ranges of the possible costs for the different ways in which the EPA may regulate coal combustion wastes (that is, hazardous or not, etc.) and then apply those ranges of costs in its IRP analyses.

Q. Have Duke and Progress properly taken the potential cost of CCW regulations into account in their IRPs?

A. No. Duke does not even discuss CCWs in its 2009 IRP. Progress mentions "consideration of coal ash as a hazardous waste" in a list of "significant challenges to deal with from a resource plan perspective," but does not appear to have reflected the potential costs in its actual planning analyses.

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23 Written Testimony of Ken Ladwig, Senior Research Manager at EPRI, before the Subcommittee on Energy and Environment of the United States House of Representatives, dated December 10, 2009.

24 "TVA Reports 2009 Fiscal Year Third Quarter Results," available at www.tva.gov/news/release/julsep09/3rd_quarter.htm.

25 For example, Duke considers ranges of potential CO_2, SO_2 and NOx allowance costs in its IRP analyses.

Q. Are there other potential regulatory compliance issues and costs that North Carolina also should be taken into account in their resource planning?

A. Yes. The already significant economic risks associated with operating coal plants will be heightened by imminent tightening of environmental regulation of pollutants produced by these plants. This year, the U.S. EPA already issued a new more demanding air quality standard for nitrogen oxides, and is scheduled to adjust standards relating to sulfur dioxide, particle pollution and ozone. EPA is also likely to issue regulations addressing interstate transport of air pollution. By 2011, EPA is scheduled to issue a federal implementation plan for regional haze, issue new source performance standards for key pollutants from electrical generating units and non-electrical generating unit boilers, and issue new standards for hazardous air pollutants, among other matters. It certainly is reasonable to expect that in most or all cases, EPA action will result in more stringent regulation of these pollutants.

Q. Do Duke and Progress adequately factor these impending air quality regulations into their IRP analyses?

A. It does not appear that Duke or Progress adequately factor into their IRP analyses the economic risks of continuing to operate existing coal-fired power plants in the face of new or more stringent air emissions requirements. Although Duke does say in its Revised 2009 IRP that it examined a range of potential SO_2 and NO_x emissions allowance prices, it does not discuss expected changes in air emissions requirements in much detail.[26] It also offers no evidence that the range

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[26] Duke Revised 2009 IRP, at pages 30-34.

of SO_2 and NO_x allowance costs it considered was reasonable. Appendix F of Progress' 2009 IRP, Air Quality and Climate Change, offers a similarly brief discussion of impending changes in air emissions requirements and also fails to explain how Progress considered these expected changes in its IRP analyses.

However, Progress includes a more complete and accurate discussion of impending regulatory changes in its *Plan to Retire 550 MWs of Coal Units Without SO2 Controls* ("Retirement Plan"), which concedes that the changes are expected to result in more stringent pollution control standards. Progress' Retirement Plan also includes a fairly realistic estimation of some of the timelines involved and indicates that Progress understands that the new standards will require the utility to alter its plans accordingly. The Progress Retirement Plan is a start at a candid and more realistic discussion of how impending pollution controls will affect the cost of continue to operate existing pulverized coal plants and will also affect the cost of construction and operation of other supply-side resources. But there is no evidence that Progress has factored the regulatory issues discussed in the Retirement Plan into its 2009 IRP.

Q. What action do you suggest the North Carolina Utilities Commission take to address this weakness in the utilities' IRP discussion of the risks associated with continuing to operate existing coal plants?

A. The Commission should require Duke and Progress, as well as other utilities, to submit as part of their IRP in this docket a detailed and accurate discussion of the expected new pollution control standards and a demonstration of how the utility is factoring the financial risk of these standards into its IRP. If, as it appears, any of the utilities has failed to adequately monetize the risk of impending regulation in their IRPs, the modeling underlying the IRP should be rerun to reflect the additional cost of continuing to run existing coal plants, and of constructing and operating supply-side resources in future.

Q. Why is it important to discuss these risks now, instead of waiting until all the expected regulations are finalized?

A. Factoring in foreseeable future regulation now will result in the utility, this Commission, and the public having better information about the true costs associated with various supply side resources as well as their relative cost when compared to demand side resources. That will translate into an improved ability to provide low cost, low risk power to the citizens of North Carolina in the future.

Q. Are you aware of any state regulatory commissions that require utilities to consider compliance with current and projected future environmental regulations in their IRP process?

A. I have not conducted a thorough review of state policies on this issue, but I am aware that the Arizona Corporation Commission recently approved an amendment to the IRP rules that would require enhanced consideration of environmental impacts of power generation. The amendment reads as follows:

Adding a new subsection to IRP rules, R14-2-703, Section D.

> "A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and a plan for reducing water consumption. The costs for compliance with current and project future environmental regulations shall be included in the analysis of resources required by R14-2-703 (D) and (E). A load-serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be

developed and reviewed by the Commission in other proceedings or stakeholder workshops." [27]

CO_2 Prices

Q. What prices did Duke assume in its 2009 IRP for CO_2 emissions?

A. Duke assumed a Base set of CO_2 prices that begins at $24.62 per ton in 2013 and increases to $93.80 per ton in 2030.[28] Duke also assumed a High set of CO_2 prices that are 15 percent above its Base set in each year and a Low set of CO_2 prices that are 15 percent below its Base set.

Q. What was the source of the CO_2 prices that Duke used in its 2009 IRP analyses?

A. In response to a data request, Duke stated that the CO_2 prices that it used in its 2009 IRP analyses were derived from the planning model used by its consultant, ICF International.[29]

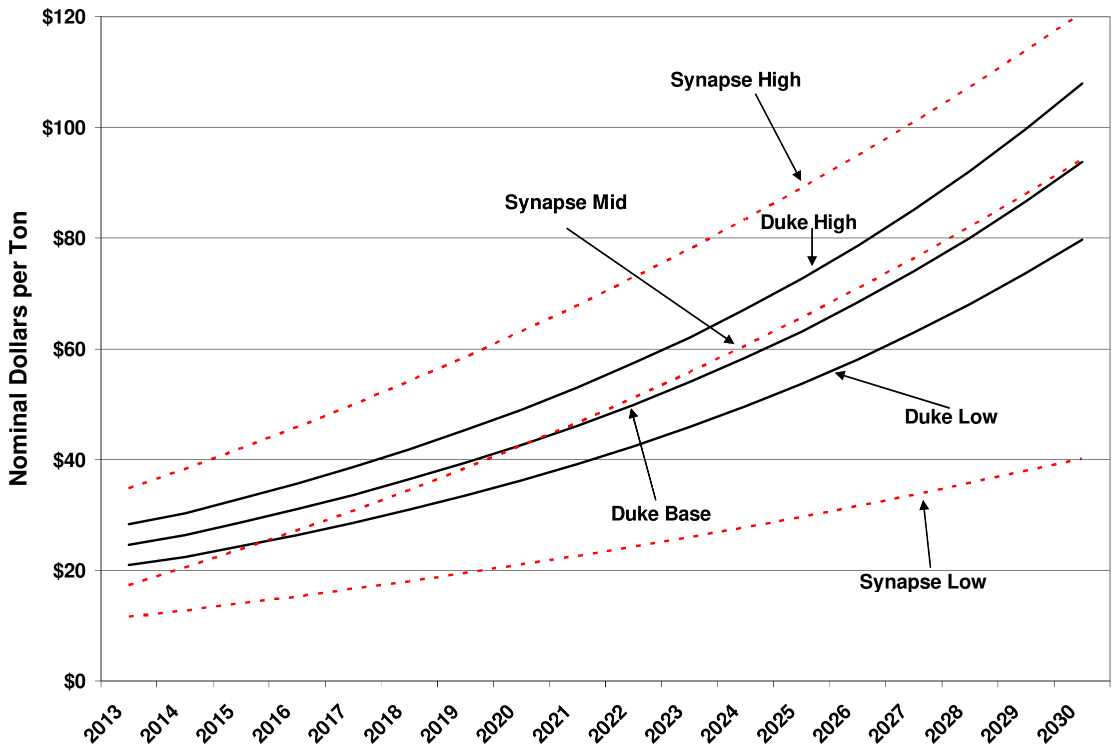
Q. Are the CO_2 prices that Duke has used in its 2009 IRP reasonable?

A. In general, yes. However, I believe that Duke should have used a wider range of scenarios than only $\pm$ 15 percent around its Base case set of CO_2 prices. It is important and prudent to consider such a wider range of possible CO_2 prices given the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions.

[27] Arizona State Corporation Commission website, available at http://images.edocket.azcc.gov/docketpdf/0000105829.pdf.
[28] Duke Response to SELC Informal Data Request No. 1.
[29] Duke Response to SELC Informal Data Request No. 11.

Figure 3, below, compares the annual CO_2 prices used by Duke in its 2009 IRP analyses with the CO_2 price projections that I helped developed in 2008 when I was with Synapse Energy Economics, Inc.[30]

Figure 3: Duke and Synapse CO_2 Prices in Nominal Dollars



As can be seen in Figure 3, the Duke Base and the Synapse Mid CO_2 price trajectories are very close – in fact, the Duke Base is above the Synapse Mid forecast in the early years. However, the Duke High CO_2 price forecast is significantly lower than the Synapse High forecast and the Duke Low CO_2 price forecast is significantly higher than the Synapse Low forecast. Because they

[30] The derivation of the Synapse CO_2 price forecasts is explained in Exhibit DAS-2.

encompass a wider range of possible future CO_2 prices, the Synapse forecasts allow for greater uncertainty than the Duke forecasts do.

Q. How do the CO_2 prices that Duke used in its 2009 IRP compare to other projections of future CO_2 prices?

A. Figure 4, below, compares the CO_2 emissions prices that Duke used in its 2009 IRP analyses with the current Synapse CO_2 price forecasts and the results of the independent modeling of the legislation that has been introduced in the U.S. Congress in recent years. These modeling analyses include:

- The U.S. Department of Energy's Energy Information Administration's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).[31]
- The EIA's October 2007 Supplement to the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.[32]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).[33]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).[34]
- The EIA's assessment of the *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009).[35]
- The U.S. Environmental Protection Agency's ("EPA")' *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).[36]
- The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).[37]

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31 Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.
32 Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf
33 Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf
34 Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
35 Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.
36 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.

- The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).[38]

- The EPA's *Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress* (June 2009)[39]

- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007).[40]

- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).[41]

- *The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts,* prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International (October 2007)[42]

- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways,* prepared by the International Resources Group for the Natural Resources Defense Council (May 2008).[43]

- *The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results,* Clean Air Task Force (January 2008).[44]

- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, April 2008.[45]

- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM),* a report by

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37 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
38 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
39 Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.
40 Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf.
41 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.
42 Available at http://www.nicholas.duke.edu/institute/econsummary.pdf.
43 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf.
44 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf.
45 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf.

the American Council for Capital Formation and the National Association of Manufacturers, March 2008.[46]

In total, these modeling analyses examined more than 85 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. In Figure 4:

- S.280 refers to the McCain-Lieberman bill introduced in 2007 in the 110th U.S. Congress
- S.1766 refers to the Bingaman-Specter bill introduced in 2007 in the 110th U.S. Congress
- S. 2191 refers to the Lieberman-Warner bill introduced in 2007 in the 110th U.S. Congress
- HR. 2454 refers to the Waxman-Markey bill introduced in 2009 in the current 111th U.S. Congress

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46 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.

Figure 4: Levelized Duke and Synapse 2008 CO_2 Prices Compared to Results of Modeling of Proposed Federal Legislation

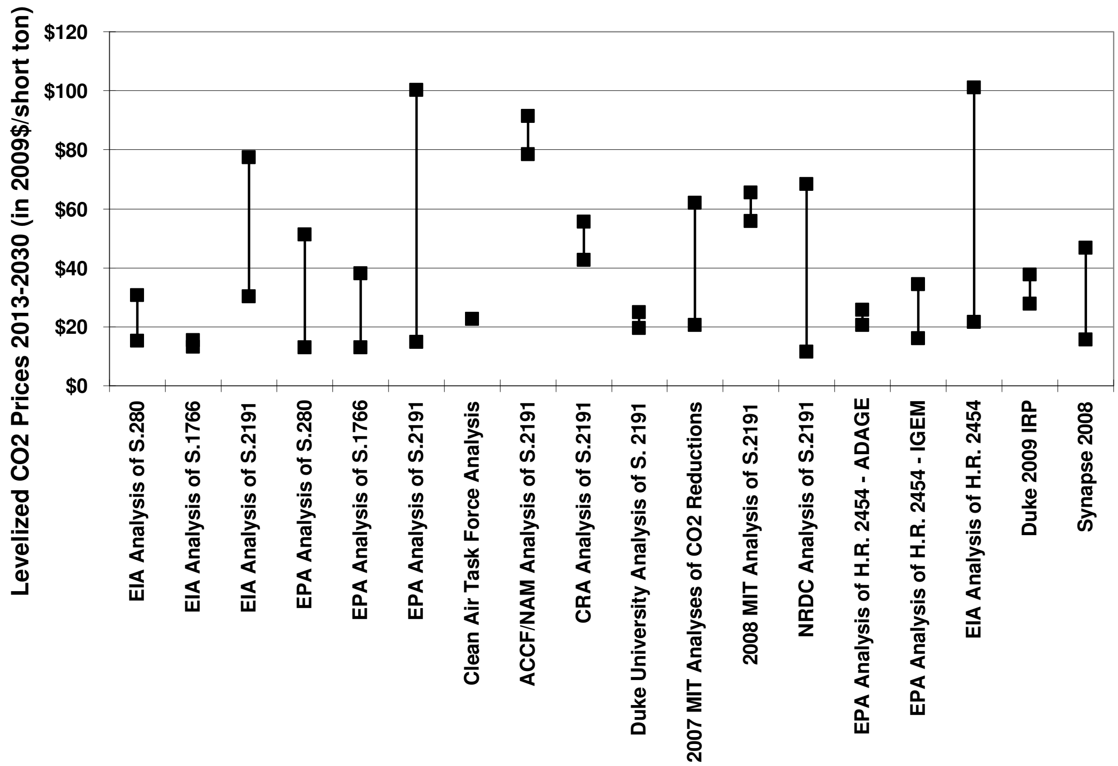

Figure 4 confirms that the range of CO_2 prices used by Duke was too narrow to reflect the potential uncertainties associated with the design and stringency of future federal regulation of greenhouse gas emissions.

Q. Does Figure 4 include the modeling of the recent Waxman-Markey bill that has been passed by the U.S. House of Representatives?

A. Yes. The third through fifth bars from the right in Figure 4 provide the ranges of levelized CO_2 prices from the recent modeling of the Waxman-Markey bill by the EIA and the EPA. However, it is not certain that whatever bill is ultimately passed by the U.S. Congress actually will reflect the terms of that legislation. This is the reason why the results of the modeling of the other legislation that has been introduced in previous U.S. Congresses remain relevant.

Q. What CO_2 prices did Progress use in its 2009 IRP analyses?

A.

Q. Are these CO_2 prices reasonable?

A. No. It is not reasonable to use a of CO_2 prices given the uncertainties associated with the timing, stringency and design of federal regulation of greenhouse gas emissions. Moreover, of CO_2 prices used by Progress in its 2009 IRP analyses is unreasonably for use as even a main or base case.

Q. How do the CO_2 prices used by Progress compare to the CO_2 prices used by Duke in its 2009 IRP analyses and to the Synapse CO_2 price forecasts?

A. As shown in Figure 5, below, the CO_2 prices used by Progress are compared to both the Duke Base CO_2 prices and the Synapse Mid CO_2 price forecast. In fact, as can be seen in Figure 5, of CO_2 prices used by Progress in its 2009 IRP analyses CO_2 prices but are than Duke's Low CO_2 prices after 2020.

PUBLIC VERSION

Figure 5: Annual Progress, Duke and Synapse CO_2 Prices in Nominal Dollars [CONFIDENTIAL]

Figure 6, below, then compares the CO_2 prices used by Progress in its 2009 IRP analyses with the Duke and Synapse CO_2 prices and the results of the modeling of the legislative proposals that were included in Figure 2 above.

Figure 6: Levelized Progress, Duke and Synapse CO_2 Prices Compared to Results of Modeling of Proposed Federal Legislation [CONFIDENTIAL]

Q. How do the CO_2 prices that Progress used in its 2009 IRP analyses compare to the CO_2 prices that other utilities and state regulatory commissions are using in resource planning?

A. As Figures 5 and 6 above show, of CO_2 prices that Progress used in its 2009 IRP analyses compared to the range of CO_2 prices that Duke used in that company's 2009 IRP, as well as the CO_2 prices that Synapse Energy Economics has recommended be used in IRP and other resource planning analyses. Figure 7, below, compares the CO_2 prices that Progress has used with the CO_2 prices that some other utilities and some regulatory commissions have been using in resource planning analyses.

Figure 7: Levelized Progress Energy CO_2 Prices Compared to Prices Used by Other Utilities and State Regulatory Commissions in Resource Planning [CONFIDENTIAL]

Q. What is your recommendation concerning the CO_2 prices that Progress should use in its resource planning analyses?

A. Progress has said that it is currently evaluating numerous possible changes to its resource plan, including additional coal unit retirements, and that it anticipates making decisions on resource options prior to filing its next comprehensive IRP in 2010.[47] The Company should use CO_2 prices in these analyses and should examine a wide range of potential CO_2 prices such as the Synapse Mid, Low and High forecasts presented in Figures 3 and 5, above.

Q. Does this complete your testimony?

A. Yes.

[47] Progress 2009 IRP at page 3.

David A. Schlissel

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SUMMARY

I have worked for thirty six years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

PROFESSIONAL EXPERIENCE

Coal-fired Generation – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Investigated whether project participants had adequately considered the risks associated with building a new coal-fired power plant. The most significant of these risks are the likelihood of federal regulation of greenhouse gas emissions and rising construction costs. Examined whether there are lower cost, lower risk alternatives than proposed coal-fired plants.

Electric System Reliability - Evaluated whether new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proosed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Analyzed power plant operating data from the NERC Generating Availability Data System (GADS). Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Nuclear Power - Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates and cost collection plans. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Electric Industry Regulation and Markets - Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Evaluated the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets. Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Evaluated whether new electric generating facilities are used and useful. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than ninety proceedings before regulatory boards and commissions in twenty three states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009
The costs and risks associated with the proposed Kemper County IGCC power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-138) –Sepember and October 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

Georgia Public Service Commission (Docket No. 27800-U) – December 2008
The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and Sepember 2008
The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008
The estimated cost of Duke Energy Indiana's Edwardsport Project.

Public Service Commission of Maryland (Case 9127) – July 2008
The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007
AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009
The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007
Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

Iowa Utility Board (Docket No. GCU-07-01) – October 2007
Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007
Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

Louisiana Public Service Commission (Docket No. U-30192) – September 2007
The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007
The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008
Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007
The appropriate carbon dioxide ("CO_2") emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana's proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – March 2007
Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

Florida Public Service Commission (Docket No. 070098-EI) – March 2007
Florida Light & Power Company's need for and the economics of the proposed Glades Power Park.

Michigan Public Service Commission (Case No. 14992-U) – December 2006
The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007
Duke's need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006
Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006
Whether APS's acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006
Quantification of plaintiff's business losses during an extended power plant outage and plaintiff's business earnings due to the shortening and delay of future plant outages. [Confidential Expert Report]

Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005
The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales. [Confidential Testimony]

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - June 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - May 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - November 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) – December 1985 and January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

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Comments on Consumers Energy's Electric Generation Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant, July 2009.

Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant. July 2009

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

The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station, April 2009.

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New Hampshire Senate Bill 152: Merrimack Station Scrubber, March 2009.

The Risks of Building and Operating Plant Washington, Presentation to the Sustainable Atlanta Roundtable, December 2008.

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Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

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Don't Get Burned, *the Risks of Investing in New Coal-Fired Power Plants,* Presentation to the New York Society of Securities Analysts, February 26, 2008.

*Don't Get Burned,*Report for the Interfaith Center for Corporate Responsibility, February 2008.

The Risks of Participating in the AMPGS Coal Plant, Report for NRDC, February 2008.

Kansas is Not Alone, *the New Climate for Coal*, Presentation to members of the Kansas State Legislature, January 22, 2008.

The Risks of Building New Nuclear Power Plants, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

The Risks of Building New Nuclear Power Plants, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

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Carbon Dioxide Emissions Costs and Electricity Resource Planning, New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

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The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

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Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

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Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

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Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2010 - President, Schlissel Technical Consulting, Inc.

2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***EX PARTE*:**	)	
APPLICATION OF	)	
ENTERGY LOUISIANA, LLC	)	
FOR APPROVAL TO REPOWER	)	
THE LITTLE GYPSY UNIT 3	)	**DOCKET NO. U-30192**
ELECTRIC GENERATING FACILITY	)	
AND FOR AUTHORITY TO COMMENCE	)	
CONSTRUCTION AND FOR	)	
CERTAIN COST PROTECTION AND	)	
COST RECOVERY	)	

REPORT AND RECOMMENDATION
CONCERNING THE LITTLE GYPSY UNIT 3 REPOWERING PROJECT

NOW COMES Applicant, Entergy Louisiana, LLC ("ELL" or the "Company"), and, pursuant to the Commission's Order No. U-30192-B dated March 13, 2009, respectfully submits this Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project (the "Repowering Project" or the "Project"). For the reasons explained more fully below, ELL recommends to the Commission that ELL (i) continue the temporary suspension of the Repowering Project; and (ii) make a filing with the Commission seeking a longer-term delay (three years or more) of the Repowering Project as well as appropriate accounting for the Project costs until the Commission can determine the permanent ratemaking treatment of these costs. A longer-term delay of the Project is appropriate given the uncertainty of various key factors that drive the economics of the Project, including but not limited to:

1) The sharp fall off in natural gas prices, both in the short term but also as projected for the long term by many industry experts, which affects the economics of the Repowering Project;

2) The implementation of various new federal energy policies, including a mandatory Renewable Portfolio Standard and other policies that may affect the economics of the Project; and

3) The uncertainties caused by the recent financial crisis and its effects on the U.S. and global economies.

The longer-term delay will allow ELL to gain better clarity regarding these uncertainties and better understand the effects of these recent changes on the economic viability of the Repowering Project. This delay is consistent with the direction set forth in the Commission's Order Nos. U-30192, dated March 19, 2008, to monitor the economic viability of this Project as part of the Commission's Quarterly Monitoring Plan process.

I. Introduction

During the past few months, there have been dramatic and unforeseeable changes in the U.S. and world economies, the likelihood of various new federal energy policies, as well as a significant decline in the prices of various commodities, including natural gas and crude oil. While it is not possible to predict accurately what the future holds, the level of uncertainty associated with these issues causes concern and a need to pause when considering a commitment as significant as the Repowering Project.

Recognizing these changes, the Commission, at the March 11, 2009 Business & Executive Meeting, issued an Order requiring ELL to suspend, temporarily and to the extent practicable, the current development of the Repowering Project.[1] Specifically, the Commission adopted a Motion stating that:

[1] Order No. U-30192-B, dated March 13, 2009.

> *There have been significant changes that have occurred relating to the Little Gypsy Repowering Project during the past few months, including the recent structural change in the market for natural gas, changes in the capital and financial markets, and the general state of the economy.*
>
> *Given these changes, I move that the Commission direct that Entergy Louisiana, LLC immediately suspend, to the extent possible, on a temporary basis, the Repowering Project and take the steps reasonably necessary to minimize project spending during the period of suspension. I understand that ELL has issued letters formally suspending certain contracts associated with the Repowering Project, and I also move that the Commission direct that these suspensions shall remain in place during the period of suspension.*
>
> *ELL is directed to continue to review the current economics of the Repowering Project and develop a recommendation regarding whether it is appropriate for ELL to make a filing with the Commission to formally delay the Repowering Project for an extended time.*
>
> *By no later than the April 2009 B&E session, ELL shall inform the Commission whether ELL intends to make such a filing.*[2]

For the same reasons that the Commission noted in its Order, prior to the issuance of that Order, ELL proactively responded to the change in the risks and expected value of the Project by taking steps to minimize spending on the Project while the Company conducted further analysis with a view toward determining whether a longer-term delay of the Project would be in the best interest of customers. ELL's analysis shows that, although there are certain risks associated with the continued volatility of natural gas, the expiration of vendor contracts, and the potential expiration of existing environmental permits for the Project, a longer-term suspension and delay of the Project is nonetheless appropriate and would be a prudent action by ELL.

Since the Commission voted to certify the Repowering Project in November 2007, ELL has, as required by Order No. U-30192 and U-30192-A[3], continually monitored the economics of

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[2] *Id.*

the Project to ensure that the Project would provide the benefits contemplated by the LPSC when it certified the Project. As part of the Commission-approved Monitoring Plan, ELL has performed and provided to the Commission, through its Staff, ongoing analyses concerning the projected net benefits of the Project to customers, using the latest information concerning a host of assumptions, including but not limited to the projected costs of natural gas, petroleum coke, coal, and carbon dioxide ("CO_2") regulation through allowances and/or taxes.

As recently as the January 8, 2009 Supplemental Monitoring Report, the Project continued to show positive net benefits to customers when compared to the alternative of a CCGT facility. In the Monitoring Report for the Fourth Quarter 2008, however, which was submitted to the Commission Staff and the Intervenors on February 16, 2009, the Repowering Project's economics, using the most recent assumptions, for the first time projected negative net benefits – indicating that the Repowering Project was projected to cost customers more than the hypothetical CCGT alternative on a net present value basis. At about this same time, on February 25, 2009, the LDEQ issued the final air permit for the Project, which otherwise cleared the way for ELL to commence on-site construction activities for the Project.

In view of the recent adverse change in the projected economics of the Project and given the significant changes in the economy and the uncertainty created by the potential development of new and in some cases more aggressive federal energy policies under the new Administration, the Company believed that it would be appropriate to further evaluate whether continuing with the Repowering Project at this time would be in the best interest of customers. Thus, the Company undertook steps to minimize spending on the Project while further analysis was performed, including, on March 4, 2009, suspending all activity under three of the four largest

[3] LPSC Order No. U-30192-A, dated July 2, 2008.

contracts relating to the Project, pursuant to the suspension terms of the contracts, and directing the vendor under the fourth contract to take substantial steps to slow the rate of spending. While ELL believes these short-term suspension steps will not immediately delay the in-service date of the Project if the Company ultimately decided to proceed with construction in the near term, the suspension of these contracts allows ELL to minimize spending while it further analyzes whether the Project continues to satisfy the objectives set forth in the Commission's certification Order U-30192, dated March 19, 2008 given recent events.

Since suspending its largest contracts and minimizing the work performed by the Project contractor, ELL has determined that it is in the best interest of customers that the Project be placed into a longer-term delay, that is, a delay of three years or longer. To implement such a delay, it will be necessary for ELL to cancel its current contracts and otherwise terminate the Project activities. However, if total costs to customers are to be minimized under a long-term delay, such steps are immediately necessary. In addition, as ELL will discuss in the last section of this report, a longer-term delay may require ELL to start over in some or all of the permitting processes. Further, if the Project is delayed for an extended period, there is a material risk that one or more permits would not be granted or would be granted subject to conditions that make the Project less attractive economically.

II. Summary of the Recommendation

The Company recommends that the Project be placed in a longer-term delay in consideration of the significant uncertainty associated with this Project caused by the recent changes that have occurred in the commodity markets, the economy, and in U.S. energy policy. A longer-term delay will allow the Company to gain additional clarity regarding a number of these issues, thus mitigating the risk that the Project will not provide long-term benefits to customers.

Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently—and for the first time—projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT[4]) resource.[5]

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 ELL to incorporate various new technologies into their long-term resource

[4] The acronym "CCGT" refers to a Combined Cycle Gas Turbine, which is a relatively newer gas-fired technology.

[5] Prior to this time, the Project had consistently been expected to provide both fuel diversity benefits and positive net economic value on a present value basis relative to a CCGT. Although the LPSC recognized that the volatility of gas prices could cause the net benefits of the Project to become negative at times, all five of the Company's prior filings (direct and rebuttal, July 2008 Monitoring Report, December 2008 Supplemental Report, and January 2009 Supplemental Report) pointed to positive net benefits. As such, this was the first time in which the fuel diversity benefit from the Project was expected to come at an additional cost to ELL customers.

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. Renewable resources are being evaluated by the Entergy System[6] and will be a key consideration in the 2009 Strategic Resource Plan.

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 a reason to delay the Project, one of the benefits of the longer-term delay will be greater level of certainty regarding this cost.[7]

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. As the Commission is aware, in addition to the Repowering Project, ELL is engaged in the Waterford 3 Steam Generator Replacement Project, which is estimated to cost

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[6] The electric generation and bulk transmission facilities of the six Entergy Operating Companies are planned and dispatched as a single, integrated electric system, referred to as the "Entergy System" or the "System." In addition to ELL, the six Entergy Operating Companies include Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc. Entergy Arkansas, Inc. and Entergy Mississippi, Inc. have provided notice of their intention to terminate their participation in the Entergy System Agreement.

[7] There have been recent updates suggesting that CO2 costs may be higher than expected at the time of certification. For example, the 2009 ICF Multi-Client Study reflects CO2 costs that are much higher than ICF predicted in the Multi-Client Study that was presented during the certification proceeding in this matter. A higher CO2 cost would adversely affect the Project economics.

approximately $511 million. ELL also is in need of acquiring additional CCGT capacity and expects to make various investments in its transmission system during the period of time that the Repowering Project is under construction. When engaging in a large project such as the 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 ELL'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 ELL to plan to fund these other projects and retain additional liquidity while delaying the Repowering Project until the additional clarity can be gained regarding the Project economics.

These revised market outlooks, particularly the sharply lower gas price forecasts, and potential policy outcomes create significant uncertainty in the economics of the Repowering Project. The change in the long-term gas forecasts reduces the value of the fuel savings that the Company and the LPSC anticipated would be provided by the Project. Thus, the "small premium" that the LPSC contemplated could be associated with the Project relative to the cost of an alternative resource such as a CCGT could be much higher—a change from all prior economic analyses, even those performed as late as January 2009. On a more near-term basis, over the first five years of the Project, the net cost to customers of the Repowering Project was originally estimated to equal $145 million; however, the current analysis indicates the total net cost to customers over the initial five years of the Project has more than doubled and is approximately $350 million.

Considered together, the uncertainties associated with the recent changes in the Project economics and market forces driving them, as well as the developments in the federal energy policy and issues raised by the turmoil in the financial markets, suggest that ELL should delay the Repowering Project for a longer term (three years or more) in an effort to gain more clarity and certainty and allow ELL to better determine whether the Project reflects the lowest reasonable cost alternative for customers or whether other alternatives will be better suited to address customer resource needs. Accordingly, ELL recommends to the Commission that ELL make a filing seeking to delay the Project for an extended period of time.

In recommending to the Commission that the Project be delayed for a longer-term, the Company is mindful of the Commission's guidance in Order No. U-30192 that the volatility of natural gas prices could cause the net benefits of the Project to become negative at times during the construction schedule and that a significant part of the justification for the Project is the fuel diversity benefits it offers – benefits not available from a CCGT alternative. The recent structural change in the natural gas market, however, suggests that, across a reasonable range of assumptions, the economics of the Project will be negative relative to a CCGT. Thus, the small "premium" caused by short-term fuel price volatility that the Commission believed could be offset by the fuel diversity benefit provided by the Repowering Project appears, to be materially larger than reasonably could have been expected. A longer-term delay will allow ELL to determine whether the Project, in fact, represents the lowest reasonable cost alternative available to diversify ELL's fuel mix to protect customers from volatile natural gas prices.[8]

[8] Although this filing is made on behalf of ELL, it should be noted that these same factors also merit a delay in the decision of Entergy Gulf States Louisiana, L.L.C. ("EGSL") to participate in the Project at this time. The Commission is considering whether to allow EGSL to participate in the Repowering Project as part of Phase 2 of this proceeding.

III. Recommendation

As noted above, ELL bases its recommendation that the Project be delayed for a longer-term on the recent and significant changes in the Project's economics. This report therefore begins by setting forth the details concerning the change in the Project's economics and discusses the uncertainties raised by the current state of the economy and possible changes in federal policy under the Obama administration. Then, to ensure that the Commission is fully informed of the Project status and spending, the report discusses the current status in some detail. Finally, the report details the current status of the various environmental permits for the Project and the effect on these permits of a longer-term delay in the Project. A longer-term delay is likely to require ELL to seek new or significantly modified permit approvals for the Project, and ELL cannot know today whether such approvals will be obtainable or what conditions may be imposed. This risk is one that ELL has considered and the Commission must consider in deciding whether a longer-term delay of the Project is appropriate.

A. Project Economics

1. Previous Economics

The Repowering Project was undertaken in large part to add supply diversity to the ELL generation portfolio and reduce reliance on gas-fired resources. ELL's generation portfolio was and continues to be weighted toward natural gas-fired resources. Relative to other utilities, ELL's natural gas dependency is high. This dependency on natural gas-fired resources exposes customers to risk relating to changes in natural gas prices. Based on the information available at the time of the original decision to proceed, the Repowering Project was the lowest reasonable cost alternative for reducing reliance on natural gas-fired resources. The Commission recognized in its Order approving the Project that the Project may result in a "small premium" for customers over its useful life relative to the cost of a CCGT resource – that is, that the cost of the Little Gypsy Repowering Project over its useful life ultimately could exceed the cost of a CCGT.[9] Nevertheless, at the time that the Repowering Project was certified, the Company's analyses indicated that it was more likely than not that the Repowering Project would be a lower cost alternative than a CCGT. The Company's analysis did indicate that there was a risk that under certain sets of assumptions, the Repowering Project could become a more costly alternative than a CCGT. The Commission found, however, that the fuel diversity benefit provided by the Repowering Project was sufficiently important that the Project should be certified despite this risk.[10]

The positive economics of the Repowering Project continued through 2008, with each Monitoring Report and a supplemental report prepared by ELL reflecting benefits from the Project. These positive economics continued even though, in 2008, ELL was required to delay the Project in order to obtain additional environmental permitting. Because of then-increasing commodity prices and the additional financing costs for a longer construction period, this delay added to the cost of the Project, increasing the total cost, inclusive of AFUDC, from $1.55 billion to $1.76 billion. However, at this time, gas prices also were increasing and reaching record high levels. Thus, the July 2008 Monitoring Report indicated that the Repowering Project continued to be economic relative to the CCGT alternative. At that time, the Net Present Value of the Repowering Project relative to the CCGT was positive $236 million, similar to the benefit considered by the LPSC when the Project was certified. Gas prices continued to trend upward

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[9] *See* LPSC Order No. U-30192 (March 19, 2008) at 17, 24,

[10] *Id*. at 24.

for the remainder of the Summer of 2008, further affirming the economics of the Repowering Project.

2. Economics Today

Recent developments in natural gas market and resulting changes in projections for long-term natural gas price levels have decreased the value of the Little Gypsy Repowering Project since the Commission certification. Thus, while the Repowering Project would provide a physical hedge against high natural gas prices, there now appears to be significant uncertainty as to the value of this hedge relative to a CCGT alternative. Given current forecasts of natural gas prices, it now appears that the CCGT alternative may be more economic than the Repowering Project across a range of assumptions.

ELL has prepared several economic analyses of the Repowering Project during the first quarter of 2009. Consistent with prior analyses, the Company used the PROSYM production cost modeling tool along with the current estimate of total Project cost, "sunk" costs, and assumptions about key inputs (forecasted natural gas prices, forecasted petroleum coke, and coal prices, etc.). These analyses compare the 40-year life-cycle economics of completing the Repowering Project with the alternative of canceling the Project and initiating a project to construct a new CCGT facility of equivalent capacity and utilization. The analyses follows the same methodology utilized by ELL in the prior viability analyses as well as the economic analysis presented in Exhibit APW-28 in the Company's Rebuttal Testimony filed in October 2007 in Phase I of this proceeding. The table below reflects the results of the ongoing Project analyses.

Table – Results of PROSYM Economic Analyses At Points in Time ($'MM)*

EFFECT ON TOTAL SUPPLY COST LG3 COMPARED WITH CCGT ($MM)	Direct Testimony (July 2007)	Rebuttal Testimony (Oct 2007)	Quarterly Monitoring Report (July 2008)	Supplemental Monitoring Report (Jan. 2009)	Sensitivity ICF Fuel / Emission Outlook (2008 / 2009)	Quarterly Monitoring Report (Feb. 2009)	Current Analysis (March 2009)
With LG3 Repowering Project							
Total PROSYM Fuel and Purchased Power	$81,821	$147,107	$166,300	$163,288	$166,900	$150,660	$155,267
Incremental Non-Fuel Revenue Requirement	$2,174	$2,237	$2,420	$2,403	$2,403	$2,403	$2,399
Total	$83,995	$149,343	$168,720	$165,691	$169,303	$153,062	$157,666
With Equivalent CCGT							
Total PROSYM Fuel and Purchased Power	$83,575	$149,093	$168,214	$165,027	$168,295	$151,964	$156,521
Incremental Non-Fuel Revenue Requirement	$514	$594	$694	$691	$691	$691	$792
Total	$84,089	$149,687	$168,908	$165,717	$168,985	$152,655	$157,313
Net Benefit / (Cost) of LG3RP over CCGT	**$94**	**$344**	**$188**	**$26**	**($317)**	**($408)**	**($354)**
Less Value of Existing LG3 Unit		($31)	($31)	($31)	($31)	($31)	($31)
Add: Committed Cost			$80	$220	$243	$274	$291
Net Present Value	**$94**	**$313**	**$236**	**$215**	**($106)**	**($165)**	**($94)**

* Values for direct testimony represent 25-year NPV. All other analyses reflect 40-year NPV values.

The current economic analysis indicates that the Net Present Value of the Repowering Project relative to the CCGT is negative $94 million. That is, as compared to July 2008, the Project economics have deteriorated by $330 million even after taking increased committed costs into consideration.

The decrease in projected Project economics between July 2008 and today is driven by an assumption of lower long-term gas prices. The July 2008 analysis assumed long-term gas prices of (2007$ levelized 2013 – 2036). The current analysis assumes long-term gas prices of (2007$ levelized 2013 – 2036). Although there has been some movement in other assumptions, which, in combination, partially offset the decrease in the gas prices, the reduction in gas prices of $1.41/mmBTU is the principal driver of the change in the overall projected economics. The table below reflects the key assumptions used in the economic analysis and how those assumptions have changed over time.[11]

Table – Key Assumptions Used In Economic Analyses

KEY ASSUMPTIONS (Levelized 2007$)							
	Direct Testimony (July 2007)	Rebuttal Testimony (Oct 2007)	Quarterly Monitoring Report (July 2008)	Supplemental Monitoring Report (Jan. 2008)	Sensitivity ICF Fuel / Emission Outlook (2008 / 2009)	Quarterly Monitoring Report (Feb. 2009)	Current Analysis (March 2009)
All in Fuel Costs for LG3 ($/mmBtu)							
Henry Hub Natural Gas ($/mmBtu)							
CO_2 Emission Cost ($/ton)							

* Included in the fundamental analysis only.

ICF International, a global professional services firm that is recognized as one of the leaders in providing expert opinions regarding the outlook with respect to fuel and emissions pricing, updated its long-term natural gas and CO_2 emissions forecast in early 2009. ELL utilized ICF's 2006/2007 Multi-client previous natural gas and CO_2 forecasts in its Rebuttal testimony in October 2007 and, therefore, has presented a sensitivity analysis of the Project economics using the updated ICF Multi-Client information. As shown in the table above, ICF's

[11] The Table reflects the 40 year analysis period used to evaluate the Project economics. Because 40-year commodity price assumptions are not generally available to the Company, ELL simply trends the cost up at an assumed rate of inflation for the years not available through the forecast.

updated 2008/2009 forecast for CO_2 emission cost is more aggressive than ELL's forecast for CO_2 costs on a long-term basis for the period extending through 2052. This higher forecast has a negative effect on the Project economics.

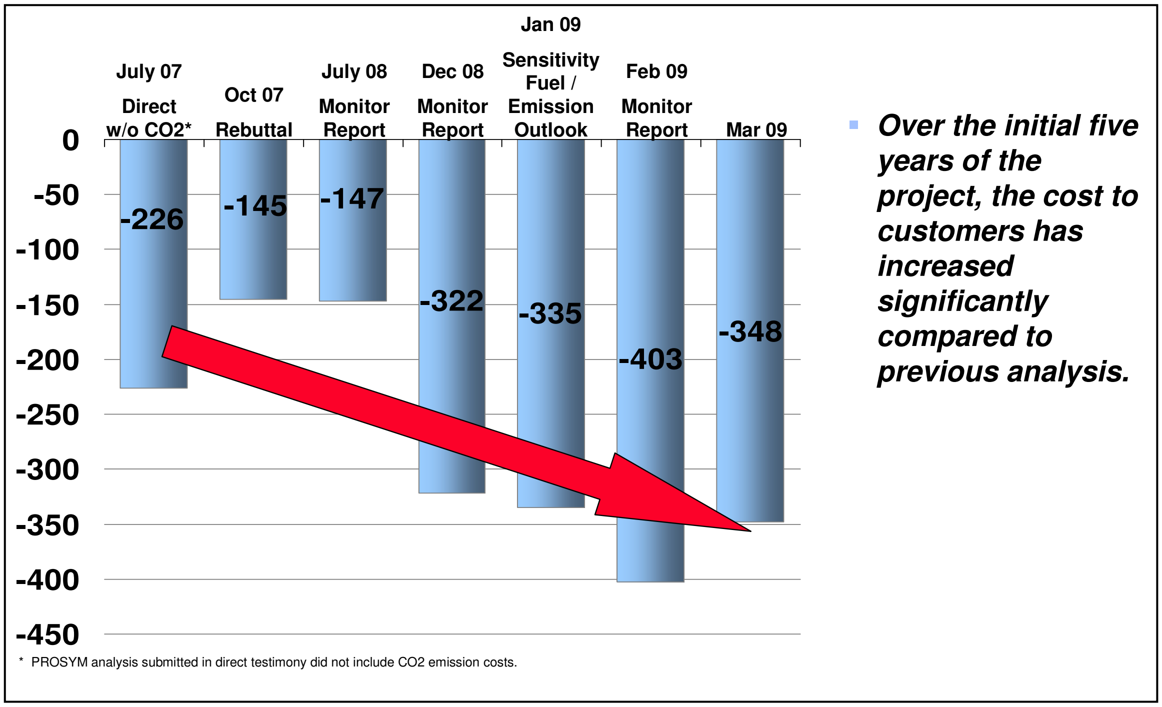
It should be noted that, in one sensitivity analysis the Company has prepared, the Project continues to reflect a break even or possibly positive economic value. This scenario assumes that the fuel mix for the Project is 80% pet coke and 20% coal, instead of the 60%-40% fuel mix that the Company has used as the reference case in all of its analyses. Utilizing a fundamental analysis consistent with the methodology used in Direct and Rebuttal testimony, if the Project burned 80% pet coke, the net benefit would improve by approximately $160 million and would, therefore, approach breakeven or, based on the recent PROSYM, be slightly positive.

ELL's most recent analysis suggests that the Repowering Project may no longer be economic relative to a CCGT alternative and addresses the effects of new and significant uncertainties that have emerged in the wake of the current economic crisis and changes that are being contemplated in federal energy policies. Although the economic results of the Project analysis are based largely on the assumed price of natural gas, as discussed subsequently, it appears that it is not unreasonable to assume that natural gas prices will remain significantly lower than the historic highs experienced in 2008. This means that the Project could, in fact, be a relatively costly physical hedge against high natural gas prices, as opposed to the "small premium" that the Commission contemplated as the possible cost of this hedge when it certified the Project. Further, one must consider these economics in light of the uncertainties caused by the current economic and policy changes.

3. Changes to the Early Year Project Economics

In assessing the potential effect of a long-term delay on the relative economics of the Project, the Company has reviewed the projected customer savings benefit or cost (when negative) over the initial five years of the Project and has compared this metric to previous analysis. As shown in the table below, the net cost to customers over the first five years has increased significantly when compared to the October 2007 Rebuttal testimony analysis.

Customer Benefits / (Costs) Over the First 5 Years of the Project ($MM)*



* Based on PROSYM analysis.

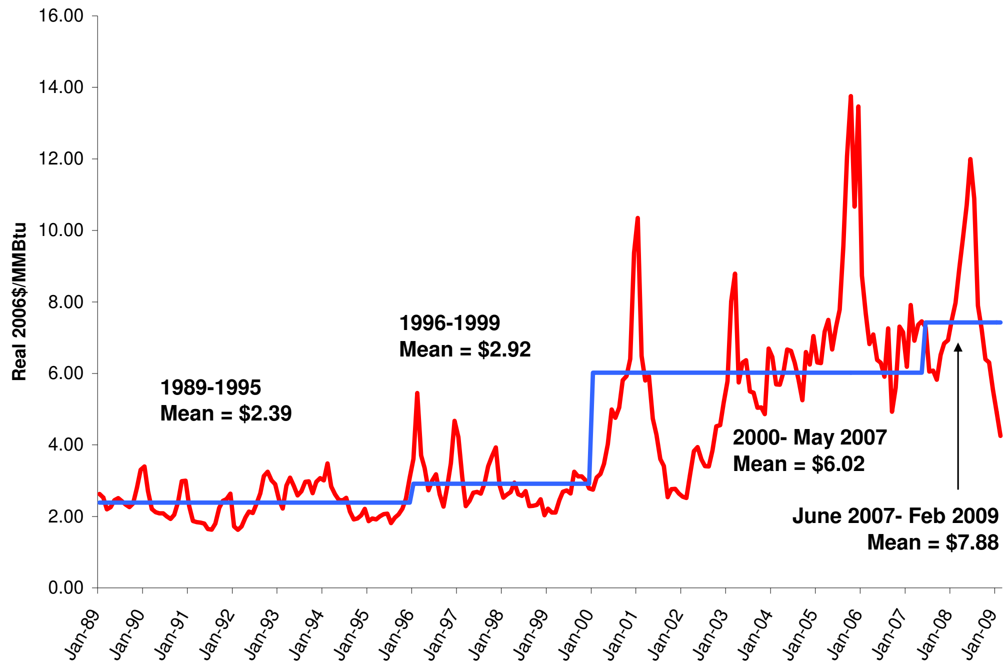
Whereas the net cost to customers was originally estimated to equal $145 million over the first five years, the current analysis indicates the total net cost to customers over the initial five years of the Project has more than doubled and is approximately $350 million. The Company recognizes this metric is not applicable when evaluating the overall life-cycle benefits of a resource; however, similar to the upward trend seen in the following discussion of the breakeven natural gas price, the trend in this metric indicates there is more risk in relying on the back-end cost benefits of the Project to produce benefits over its life-cycle. The higher customer costs in the first five years of the Project life, stemming mainly from lower expected natural gas prices in these years, supports the rationale for a longer-term delay in the Project. Delaying the Project provides headroom by avoiding substantial costs during the periods when gas prices are projected to be lower, and the Project does not provide customers with total savings.

4. Recent Natural Gas Developments

Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $13.32/mmBtu. Since that time, natural gas prices have declined sharply, with recent Henry Hub prices $3.63/mmBtu (nominal).[12] The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.

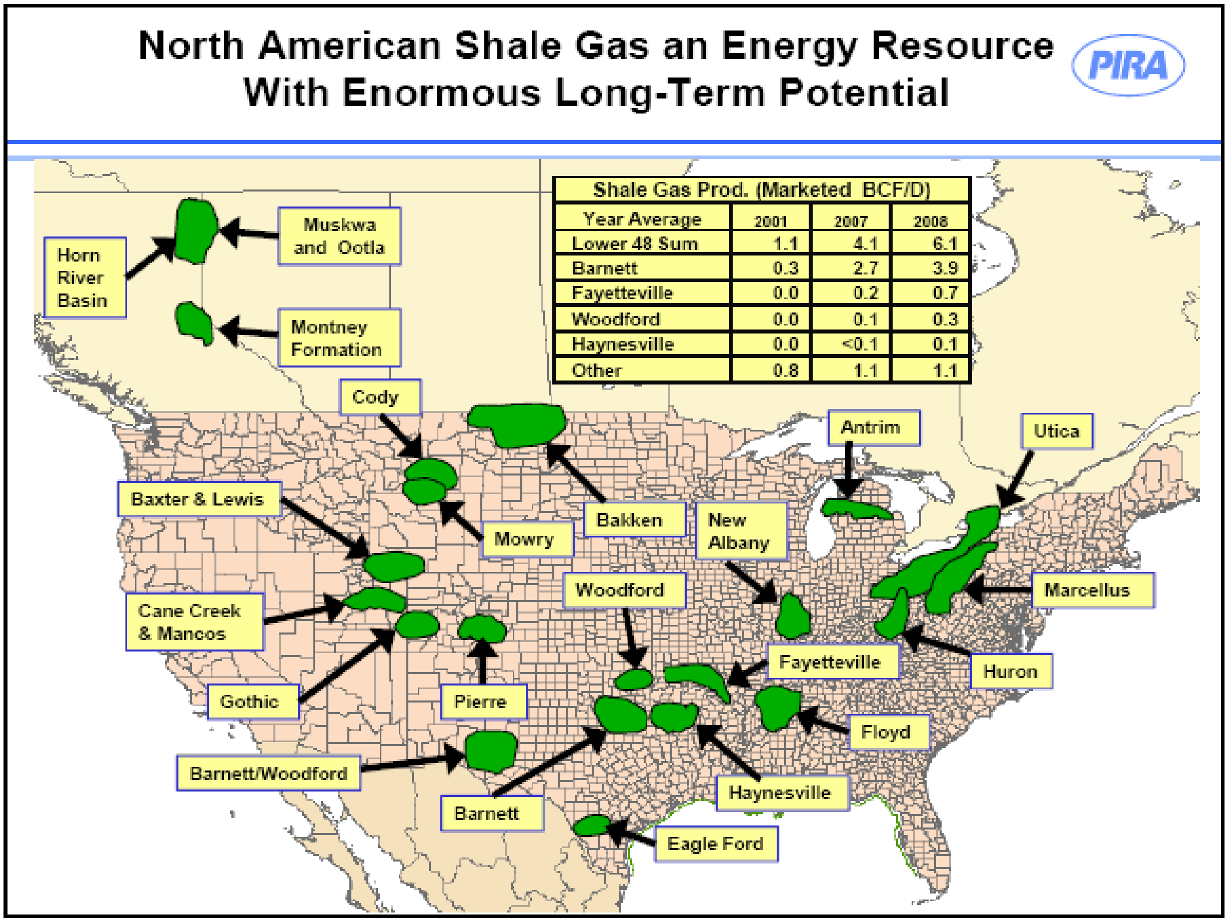
[12] NYMEX settlement for Henry Hub contracts for April 2009

Historical Natural Gas Prices and Volatility



However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run. From 2001 to 2008, shale gas production in the lower 48 states increased from 1.1 billion cubic feet per day (BCF/D) to 6.1 BCF/D, an increase of more than 450%.

North American Shale Gas



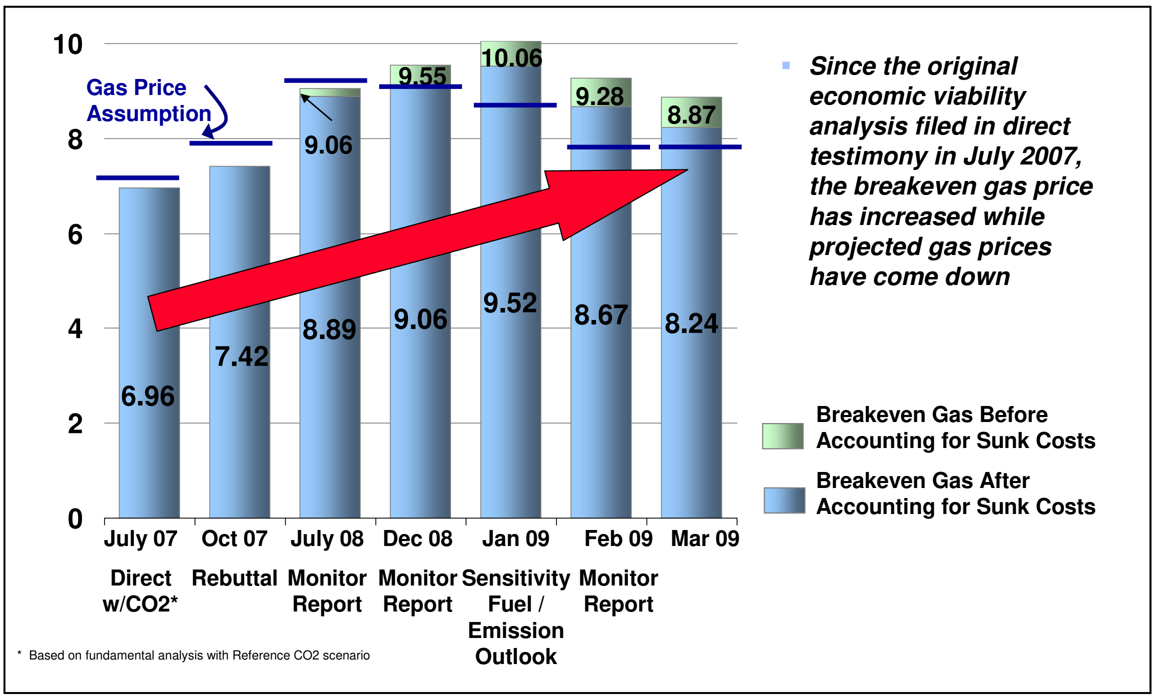
Source: PIRA

5. Breakeven Gas Price

In order to assess further the implications of current gas price projections on the long-term Project economics, the Company has assessed the "breakeven" gas price for the Project over the course of the Project. The "breakeven" gas price is the gas price at which the economics of the Project would match those of a CCGT alternative, that is, the gas price that would give the CCGT alternative the same net present value as the Repowering Project. If the price of natural gas is expected to exceed the breakeven price, then the Project would be economic (less expensive) relative to a CCGT alternative. If the price of natural gas is below the breakeven price, then the Project would be uneconomic (more expensive) relative to a CCGT.

The breakeven analysis relies on a fundamental analysis consistent with the methodology used in ELL's Direct and Rebuttal Testimony. The analysis indicates that, given current assumptions, including accounting for the Project's sunk cost, the breakeven gas price is approaching $8.24/mmBtu (in real 2007 $s). In other words, the Repowering Project is economic relative to the CCGT only if gas prices average above this level on a real, levelized basis over the life of the Project. Below is a chart comparing the breakeven price of natural gas that is required to cause the Project to be economic relative to a CCGT alternative across several different points in time.

Breakeven Gas Price ($/mmBtu)



Notes:
1. All gas prices quoted in real 2007 dollars.
2. Direct and Rebuttal Testimony based on 30-year fundamental analysis for 2012 – 2041. All other analysis based on 40-year analysis for 2013 – 2052.

As shown in the above chart, the analyses conducted over the course of the Project indicated that long-term gas price projections were above the Project's breakeven gas price until early 2009. This relationship suggested that the Repowering Project was likely to be economic relative to a CCGT alternative in the long-run. In the current analysis, however, the relationship has reversed. The breakeven gas price is now above projected long-term gas prices. Moreover, the gap between projected long-term gas prices and the breakeven gas price is $0.45/mmBtu ($7.79 projected compared with $8.24 breakeven) in real 2007 dollars when including sunk costs and over $1.00/mmBtu when excluding sunk costs.

The conclusion from the breakeven analysis is that one must believe that the levelized price of natural gas must remain higher than $8.24 (real 2007 dollars) over the life of the Project if it is to provide economic benefits to customers. In this case, however, as discussed previously, there is a reasonable basis to question this assumption due to the enormous potential of non-conventional resources and other forces that will help to lower natural gas prices. Thus, the breakeven analysis supports a longer-term delay of the Project.

6. Conclusions Regarding Economic Analysis

The cost of the Repowering Project and that of other baseload generation alternatives are subject to significant uncertainties that can change materially their relative economics. In the case of the Repowering Project, a chief uncertainty is long-term natural gas price levels, but the Project also is influenced by the effects of potential energy, environmental and policy issues, which are discussed in the next section, and by whether the timing of this investment is appropriate given the current capital markets. As recognized in the Commission's Order certifying the Project, "the cost-effectiveness of the Repowering Project remains very uncertain because one cannot predict with certainty the ultimate cost of possible CO_2 regulation and natural gas prices over the next 30 years."[13]

At the time of the certification proceeding and through the beginning of 2009, the Project was expected to produce both fuel diversity benefits as well as net economic benefits relative to a CCGT supply alternative. Thus, the important fuel diversity benefit of the Project was expected, under most assumptions, to be economic relative to a CCGT alternative.

Today, this conclusion is uncertain, and this uncertainty is the reason that ELL seeks a longer-term delay of the Project. Recent significant changes in the natural gas market and resulting structural declines in projections of long-term gas prices now make the expected economics of the Repowering Project less attractive relative to a CCGT alternative. Given the current cost of the Project and projected long-term natural gas prices, the Repowering Project does not appear to represent the lowest reasonable cost alternative for meeting ELL's baseload needs at this time. Further, there are new risks to the Project's long-term economics raised by the structural change in the natural gas market and ongoing economic crisis and emerging federal response and potential policy initiatives and timing, which were not knowable at the time of the earlier Project decisions. These new uncertainties pose additional risks to long-term electricity demand and supply requirements that suggest the timing of the Project should be reconsidered.

Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and ELL cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods. Thus, the cost premium that the LPSC believed might be

[13] Order No. U-30192 (March 19, 2008) at 28 (referring to testimony of Staff witness Matthew Kahal).

"small," as stated in its Order,[14] could be much higher. Under these circumstances, ELL believes that it is appropriate to delay the Repowering Project at this time and revisit this option in the future.

C. Uncertainties that May be Resolved During the Longer-Term Delay

Although changes in the natural gas market (and the associated changes in the expected future path of natural gas prices) is a key driver of the Company's recommendation at this time, the ultimate economics of the Repowering Project are also a function of the outcome of a variety of additional factors, each of which is highly uncertain. These include the long-term effects of the current global recession on the demand for energy; the possible imposition of federally-mandated RPS, which could change the structure of ELL's portfolio and further depress the long-term price of natural gas; the sustainability of the long-term non-conventional natural gas supply, which is a key driver of the expected lower natural gas costs; additional clarity regarding the cost of CO_2 compliance; the possibility of capturing lower long-term commodity costs in a future project; and, other factors. Continuing with the Repowering Project at this time would result in an irreversible investment decision based on the significant capital requirements associated with this Project, yet the resolution of the various uncertainties could produce scenarios in which the outcome of a decision to proceed would not benefit the Company's customers.

At this time, because of lower natural gas prices, the Commission and the Company have the ability to mitigate the effects of these uncertainties by exercising flexibility and delaying decisions that otherwise would result in irrevocable capital expenditures. Delaying a final

[14] Order No. U-30192 (March 19, 2008) at 24.

investment decision can create value for ELL customers by providing time to clarify and resolve uncertainties, increasing the likelihood that the Project, if ultimately undertaken, will produce net benefits for ELL customers over its lifetime. For instance, during a two or three year delay period, ELL is likely to learn whether we are in a severe but short recession or a long-term period of slow growth; whether the U.S. Congress will pass RPS and/or CO_2 legislation and, if so what the cost of compliance might be and the effect on ELL's resource needs; and, the extent to which the development of North American non-conventional gas reserves will constrain domestic natural gas prices for an extended period of time. Greater clarity on all of these uncertainties, about which much will likely be learned over the next two to three years, will allow a better final investment decision to be made. Because it is reasonable to expect that at least some additional clarity regarding these key issues will emerge over the next few years, a decision to delay is reasonable and prudent.

D. Capital Considerations

As the Commission is no doubt aware, the United States and world are in the midst of a severe economic crisis. The capital markets have become increasingly constrained, and investors are charging large premiums to invest in bonds, even in the case of utilities, which traditionally have been considered so-called "safe harbor" investments. While ELL cannot know today how the financial turmoil will affect the funding of the Project, it is reasonable to expect challenges and possibly added cost, which would weaken further the Project economics. Given the uncertainties in the economics of the Repowering Project, it would seem to be a more prudent use of capital for ELL to plan to fund these other projects and preserve its liquidity for unexpected events while delaying the Repowering Project until the additional clarity can be gained regarding its economics.

ELL discussed issues involving access to capital in its Direct Testimony in Phase 2 of this proceeding. However, at the time of that filing, ELL did not know whether the current tightening of the credit markets would be sustained. It now appears that it could take several years for the financial markets to recover.

The turmoil in the financial markets must cause ELL to consider the timing of investing in a capital project of the size of the Repowering Project given its uncertain economics and ELL's need to fund a number of other large investments. ELL is engaged in the Waterford 3 Steam Generator Replacement Project, which was recently certified by the Commission, and is estimated to cost approximately $511 million. ELL also is in need of acquiring additional CCGT capacity and has opportunities currently available to it. ELL expects to make various investments in its transmission system during the period of time that the Repowering Project is under construction. On top of these capital needs, ELL must seek recovery for its costs associated with the 2008 Hurricanes Gustav and Ike. The current estimated cost of these storms to ELL is $390 to $405 million, and there is a need to fund the depleted storm reserve. Although ELL expects that it will be permitted to recover its prudently incurred storm costs, that recovery is not likely to begin until 2010, and ELL is, therefore, entering the 2009 hurricane season with no storm reserve and no funding in place for its outstanding storm costs. Taken together, the projects that ELL needs to complete and ELL's need to ensure that it has adequate liquidity to address storm events counsel against undertaking an investment of the size of the Repowering Project at this time given its declining economics.

The longer-term delay of the Repowering Project will allow ELL to concentrate its financial resources on projects such as the Waterford 3 Steam Generator Replacement Project and on CCGT and transmission investment, all of which will provide benefits to customers. The delay also will permit ELL to resolve its cost recovery for Hurricanes Gustav and Ike. Given the uncertain economics of the Repowering Project, ELL believes that it is prudent to concentrate its resources on these other projects and preserve its liquidity for unexpected events until additional clarity can be gained regarding the economics of the Repowering Project.

E. Potential Supply Options

As part of the ongoing supply planning process and in light of the uncertainty associated with this Project, the Entergy System currently is pursuing the following initiatives to evaluate other supply options:

- Renewable Resources – The Entergy System issued a Request for Information ("RFI") for Renewable Resources to the market on March 31, 2009 in an effort to obtain information from third parties regarding the potential for the development of renewable generation resources in the area in which the Entergy System provides service. This information will prove valuable as ELL assesses the effects of a likely RPS as discussed herein and which technologies may be most appropriate to meet the needs of customers as well as the RPS.
- Energy Efficiency – The System currently is pursuing various initiatives regarding energy efficiency, including fulfillment of a commitment in this proceeding to complete a study of the DSM potential in the areas served by

ELL and Entergy Gulf States Louisiana, L.L.C ("EGSL").[15] The role of DSM in long term planning also is included in the LPSC's ongoing Integrated Resource Planning ("IRP") Docket. Finally, demand response programs and time-of-use rates were piloted by EGSL in 2008 and will be further evaluated in 2009 as part of the second phase of the advanced metering infrastructure (AMI) pilot in Baton Rouge.

- Long Term CCGT Resources – The System continues to evaluate opportunities for the procurement of long-term CCGT resources and, on March 31, 2009, posted notice that it intends to move forward with a long-term RFP for these resources. This RFP will include a self build CCGT option at the Company's Ninemile site, which will be compared against other market alternatives. In addition, the System continues to be in discussions with various suppliers for resources that may provide compelling benefits to customers.

IV. Status of Project Development and Spending

ELL has incurred approximately $160 million of cost through February 28, 2009 on a life-to-date basis for the Repowering Project. ELL estimates that, should it cancel the Project, the total cost of the Project would be approximately $300 million, including actual spending and estimated contract cancellation costs, although the total cost could be higher depending upon when the contracts are cancelled. The portion of this figure attributable to contract cancellation

[15] As previously discussed in testimony before the LPSC, DSM is not a substitute for the supply role that would be provided by the Repowering Project. However, it will help meet the Companies' resource needs and may, with other initiatives, affect the total resource portfolio.

costs is only an estimate, as ELL must negotiate with many of the Project vendors in order to determine the actual cancellation costs. ELL has necessarily focused its discussions to date with vendors on issues surrounding the temporary suspension of the contracts; as such, ELL is not yet in a position to report on the status of the negotiation of cancellation costs for those contracts. ELL plans to begin canceling these contracts over the next few weeks and will be able to develop a complete cost estimate after it completes these cancellations and can determine the full costs to which it is obligated.

During February 2009, the Company determined that, in light of the deterioration in the Project's projected economics and other factors, including recent changes at the federal level, it would be appropriate to slow the rate of spending on the Project while further analysis was undertaken concerning the continued viability of the Project. During this time, the Company directed the Project Team to take necessary steps to minimize the costs incurred for the Project while also balancing the necessity of maintaining the projected in-service date. The Project Team analyzed the four largest contracts where the majority of dollars were being expended and identified discretionary steps that it could take to minimize spending during this period without immediately affecting the Project's construction schedule or projected in-service date. The Project Team also suspended entering into any new contracts unless they were required to maintain the construction schedule. For those that were required to maintain the construction schedule, when feasible, the Project Team bifurcated the new contracts to enter into only the required portions and to defer the remainder.

On March 4, 2009, as part of the above-described effort to slow Project spending, the Company instructed the Project Team to suspend substantially all activity under three of the Project's four largest contracts in order to minimize cost. The terms of these contracts permit

ELL to suspend activity under the contracts for a limited period of time, as it deems necessary, without having to cancel the contracts and renegotiate new contracts if the Project were to move forward. In addition, as of early March 2009, work under each of these contracts had progressed to a point that suspension would not be expected to affect the construction schedule significantly. However, the maximum time that these contracts may remain under suspension ranges from three months to one year. If the suspension exceeds the maximum time allotted, the contracts accord the vendors a right either to cancel their contracts or require a renegotiation of terms. Suspensions longer than three months are therefore impracticable, as the resulting contract cancellations would require that new contracts be negotiated and priced with either the same or new vendors.

Further, ELL is generally responsible under the contract terms for reimbursing incremental costs incurred during suspension. These incremental costs could include costs of storage, transportation to storage, and corrosion protection, among other items.

In addition to the above efforts to suspend activities under significant contracts, ELL directed its Engineering, Procurement, and Construction ("EPC") contractor, which is the principal contractor for the Project, to slow spending, including, specifically to do the following:

- defer any planned personnel moves, site mobilization, or additions to the project team;

- allow project team reductions for all personnel not listed as key personnel (reduction in key personnel must have ELL approval, per the contract);

- continue requests for proposals and evaluations of pending purchase orders and subcontracts, but not to approve any additional subcontracts or purchase orders without ELL approval;

- demobilize the site preparation subcontractor as required to limit activities to returning the site to an acceptable condition, and, further, to demobilize all personnel and equipment not required for this activity; and

• work with ELL to determine other cost control actions to reduce cost commitments and evaluate the requirements to maintain Work and Agency Orders that ELL suspends.

ELL believes that it should manage the Project spending consistently with the objective of obtaining a longer-term delay and further minimizing costs to customers, unless otherwise directed by the Commission. Thus, ELL plans to take immediate steps to minimize spending further on the Project, including the termination and/or cancellation of current contracts with vendors.

The timing of the cancellation of the contracts is important; in general, the sooner the contracts are cancelled, the lower the cancellation costs. The Project contracts have limited suspension periods, generally ranging from three months to one year, and contract provisions allow vendors to be compensated to maintain the suspensions. Thus, ELL must establish a timely suspension management plan. As part of this plan, ELL intends to cancel its contracts in April 2009.

It is important to understand that the management of the Project spending and contracts would differ if the contracts were being managed with a view to being able to restart the Project in the next three months to one year and that, if the Project were to be restarted within this time, there could be additional costs beyond those contemplated by the current Project estimate such as, for example, storage costs and costs to treat and protect fabricated materials so that they would be available for use when the Project resumed. However, given the high probability that the economic viability of the Project will not materially improve over the near term and considering the need to minimize overall costs for ELL and its customers, ELL believes that it is appropriate to implement a longer-term delay and immediately begin the orderly winding down of Project activities

V. Status of Environmental and Other Permits

ELL has obtained all major environmental permits required to begin construction of the Project. As detailed below, however, a delay in the Project places these permits at risk and may adversely affect the Project's economics and technological feasibility in the event the Project were later re-initiated. Below is a list of the major environmental permits that it needs to commence construction, including the following:

Type	Permit	Issuer
Air	Prevention of Significant Deterioration Permit To Construct	Louisiana Department of Environmental Quality ("LDEQ")
Air	Title V Operating Permit, including case-by-case Maximum Achievable Control Technology ("MACT") analysis	LDEQ
Air	Title IV Acid Rain Permit	LDEQ
Water	Section 404 Dredge and Fill ("Wetlands") Permit/Section 10 Rivers and Harbors Act Permit	U.S. Army Corps of Engineers
Water	Section 401 Water Quality Certification	LDEQ
Water	Coastal Use Permit	Louisiana Department of Natural Resources ("LDNR")
Water	Stormwater Control Permit/General Permit Coverage	LDEQ
Land Use	Project Approval	Lake Ponchartrain Levee Board

In addition to the above permits, which have been obtained, additional permits – (i) for modifications to wastewater discharges (Louisiana Pollutant Discharge Elimination System permit modification) and (ii) for the proposed post-combustion product landfill (solid waste permit) –must be obtained. These last two permits are not required to commence construction on the Project but would be required prior to operation of the new generating unit (for the wastewater permit) and prior to the start of landfill construction (for the solid waste permit).

Importantly, a short-term or longer-term delay in the Project would affect the above-described permits in a variety of ways. A short-term delay in the Project – lasting approximately 60-90 days – would affect only the Prevention of Significant Deterioration Permit To Construct. Specifically, if construction on the Project does not begin by May 30, 2009, an extension of the required start-by construction date included in the Prevention of Significant Deterioration Permit To Construct would be required. LDEQ originally issued this permit on November 30, 2007, and it expires on May 30, 2009 unless construction has begun or binding commitments to begin construction have been entered by that date. However, an extension of the construction start date requirement can be requested from LDEQ. Nonetheless, this is the most pressing deadline related to the environmental permits.

A suspension or multi-year delay in the Project would affect the permits in other, more significant ways. ELL would be required to seek renewal of existing permits, permit extensions, or new permits for the Project, including new air permits. Moreover, it is possible that any extensions, renewals, or new permits would contain new provisions that would have a significant effect on the economics or technological feasibility of the Project. If it proceeds with implementing a longer-term delay in the Project, ELL would seek extensions or renewals of the permits, when allowed by law or regulation and when beneficial to continuing Project viability, but it is not possible to know whether such extensions would be granted or for what period of time. Thus, if a decision is made to delay the Project for an extended period, that choice should be made with an awareness and acceptance of the fact that, as a result, ELL may be required to start over in some or all of the permitting processes. Further, if the Project is delayed for an extended period, there is a material risk that one or more permits would not be granted or would be granted subject to conditions that make the Project less attractive economically.

In particular, and in addition to the effects described above, the longer-term delay of the Project would affect the various permits as follows:

- Title V Operating Permit: LDEQ issued this permit initially on November 30, 2007 (without the MACT determination, which was added later as a modification). The permit expires on November 30, 2012 unless an application for renewal is filed on or before May 30, 2012. The permit also requires that construction begin within two years of permit issuance, or by November 30, 2009. ELL can request an extension of this deadline.

- New Regulatory Requirements: ELL may be required to comply with new regulatory requirements relating to air emissions that become effective before the onset of construction or before permits are extended or renewed. Examples of these requirements are limits on the emission of carbon dioxide and other greenhouse gases, technological standards for mercury and similar emissions, and additional controls required by tightened national ambient air quality standards for ozone that may affect St. Charles Parish. In particular, a designation of St. Charles Parish as not in attainment of EPA's new ozone standard could require LDEQ to deny an extension of the construction start-date requirement in the PSD permit in favor of requiring a new permitting process.

- Wetlands Permit/Section 10 Rivers and Harbors Act Permit: The Corps of Engineers permit expires on February 28, 2014. ELL would require an extension to continue construction operations regulated by this permit after that date.

- Coastal Use Permit: This permit expires on January 9, 2014. Extensions are not provided for this type of permit, so a new permit may be required if construction activities allowed by the permit are not completed by that date. The permit requires that "reasonable progress" continue to be made on the project during the life of the permit. If a new permit were required, new proposed regulations that would require the "beneficial use" of dredged materials could apply to the project, increasing mitigation costs.

Recently, new issues have arisen regarding EPA's jurisdiction over CO_2 emissions. In the wake of the United States Supreme Court's decision in *Massachusetts v. EPA*, EPA is expected to publish a determination in April 2009 that CO_2 emissions cause or contribute to an endangerment to human health and welfare. This "endangerment finding" is a condition precedent to EPA's regulation of CO_2 emissions from mobile sources, such as automobiles and trucks, under Title II of the Clean Air Act, § 201(a)(1). Once EPA makes the endangerment finding, the agency must then develop applicable emissions standards for mobile sources. These emission standards are not to take effect, however, until "after such period as the Administrator finds necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period." CAA § 202(a)(2). It is unknown whether the endangerment finding would have an effect on the pending permit; however, assuming that the Company was able to gain an extension of the PSD permit, if construction did not begin by the expiration of the extension period, and a new PSD permit was required after the promulgation of CO_2 regulations, that permit likely would include CO_2 limits or technology requirements that differ from those present under the existing PSD permit.

VI. Conclusion and Recommendation

For the reasons set forth above, ELL recommends to the Commission that ELL (i) continue the temporary suspension of the Repowering Project; and (ii) make a filing with the Commission seeking a longer-term delay (three years or more) of the Repowering Project as well as appropriate accounting for the Project costs until the Commission can determine the permanent ratemaking treatment of these costs.

Respectfully submitted,

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New Orleans, Louisiana, this 1st day of April, 2009

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Energy Economics, Inc.

Synapse 2008 CO_2 Price Forecasts

July 2008

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1. INTRODUCTION

Synapse has prepared a 2008 CO_2 price forecast for use in Integrated Resource Planning (IRP) and other electricity resource planning analyses. The 2008 Synapse Low CO_2 Price Forecast starts at $10/ton[1] in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars. The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013, in 2007 dollars, 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 in 2007 dollars, but then climbs to $53/ton by 2030. The levelized cost of this mid CO_2 price forecast is $30/ton in 2007 dollars.

In 2006, Synapse developed a set of CO_2 price forecasts for use in IRP and other electricity resource planning analyses.[2] Those forecasts ranged from a low of $10.23 levelized over the years 2013-2030, to a high of $37.11 levelized over the same period (all in 2007 dollars).

Significant developments in the past two years led Synapse to re-examine and revise its 2006 CO_2 price forecasts to ensure that these forecasts reflect an appropriate level of financial risk associated with greenhouse gas emissions. 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 contain emissions reductions that are 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. In addition, in the past two years, additional information has been developed regarding technology innovations in the areas of renewables, 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

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1 Throughout this paper, emission allowance prices are quoted in dollars per ton. This should be interpreted as dollars per short ton of CO_2. Prices in the economic literature and in international trading are often quoted in dollars per metric ton of CO_2 or dollars per metric ton of carbon, but the units we use are more typical of US carbon pricing schemes.

2 CO_2 price: Carbon dioxide (CO_2) is one of a cohort of six gases known to contribute to the atmospheric greenhouse effect which are collectively called greenhouse gases, or GHG. Most of the policies being designed at state, federal, and international levels propose to limit emissions of CO_2 as well as methane (CH_4), and nitrous oxide (N_2O), amongst others. Although these other gases are more potent greenhouse gases than CO_2, carbon dioxide is far more abundant and is the primary greenhouse gas emitted as a result of fossil fuel combustion. The “allowance price” is the price to emit one unit of CO_2, or more precisely, quantity of GHG equivalent to the 100-year global warming potential of one unit of CO_2. In shorthand and for simplicity, we refer to the “allowance price to emit one short ton of carbon dioxide equivalent greenhouse gas” as the “CO_2 price”.

allowance prices in electricity resource planning and selection for the period 2013 to 2030.

As discussed in our earlier carbon price reports, we conclude that federal regulation of greenhouse gas emissions is certain. However, the costs of any program will be affected by important details that are still uncertain, such as the timing, goals, and design of the program that will ultimately be adopted and implemented. Therefore, it is critical to consider a reasonable range of CO_2 emissions allowance prices in resource planning to achieve decisions that are robust in an uncertain future just as resource planners normally consider a range of fuel prices. For this reason, we provide high, low and mid CO_2 allowance price forecasts.

This report discusses the specific factors and developments that we have considered in re-examining and revising the Synapse forecast of CO_2 prices for use in resource planning and selection. In general, our CO_2 price forecasts are based on:

1. Our review of the current political conditions in the U.S. concerning the issue of climate change and responses thereto;
2. The results of publicly available modeling analyses of greenhouse gas regulatory proposals in the current U.S. Congress;
3. The ranges of CO_2 prices used by utility regulatory commissions and utilities in electric resource planning;
4. Our review of the estimated costs for technological solutions to electric sector carbon emissions such as energy efficiency, renewable resources, nuclear power, and carbon capture and sequestration;
5. Our work experience and professional judgment on global climate change and electric resource planning issues.

2. NEW DEVELOPMENTS SINCE THE SPRING OF 2006

The most significant new developments since Synapse released its original CO_2 price forecasts in the spring of 2006 include the following:

Increasing Evidence of Climate Change

The Intergovernmental Panel on Climate Change (IPCC) released the IPCC Fourth Assessment Report, in 2007.[3] This report, a consensus document reflecting the views of hundreds of the world's top climate scientists, concluded in far stronger language than had any previous version that the climate of the Earth has been, and will continue to be, adversely affected by human-induced climate change. The report noted that "warming of the climate system is unequivocal", and that "Observational evidence from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases." The report documents increases in both surface temperature and sea level, as well as reductions in snow cover, that result directly from human activities. Finally, the report notes that "Continued GHG emissions at or above current rates would cause further warming and induce many changes in the global climate system during the 21st century that would *very likely* be larger than those observed during the 20th century."

The IPCC report, and numerous related scientific studies and reports, continue to corroborate and strengthen a consistent message: while uncertainties remain in the nature and timing of certain specific *impacts* of climate change, human-caused climate change is now established beyond any credible scientific doubt. The social and economic costs of climate change will be large and detrimental to societies all over the world, although those in less-developed regions are more likely to suffer greater damages in the short term. Importantly, the expected damages and costs associated with climate change rise with increasing levels of greenhouse gases in the atmosphere, as do the risks of crossing dangerous thresholds into cataclysmic impacts, such as the loss of the largest Antarctic glaciers and the resulting inundation of coastal regions around the world. Actions taken by governments and societies today will make an enormous difference in the ultimate economic and societal costs and dislocations associated with climate change.

Increased Political Support for Serious Government Action on Climate Change

A number of developments demonstrate growing political support for, and anticipation of, serious action by federal and state governments in the U.S. to mitigate climate change. These developments include:

- Bipartisan support for climate change legislation – Senators and representatives of both major parties support the climate change legislation introduced in the

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3 http://www.ipcc.ch/

current Congress, and the presumptive nominees for President from both major parties also support some form of aggressive climate change legislation.

- Carbon Principles issued by three leading financial institutions – Citi, JPMorgan Chase, and Morgan Stanley developed climate change guidelines for advisors and lenders to power companies in the United States. These Principles create an approach to evaluating and addressing carbon risks in the financing of electric power projects.[4] Several other financial institutions, such as Bank of America and Credit Suisse, have adopted the Principles.
- State and Regional Actions to reduce greenhouse gas emissions – More than 30 states have developed or are developing climate change plans. Some states, like California, Montana, Oregon and Washington, have adopted explicit performance based standards regarding long-term investments in baseload generation. The California Energy Commission requires that new investments in baseload generation comply with a standard of 1,100 lbs of CO_2 per MWh. The Northeast states are implementing a regional cap on carbon emissions. States in the upper Midwest and the West are also acting regionally to address CO_2 emissions. As of Dec. 2007, 25 states had adopted Renewable Portfolio Standards that require certain percentages of energy consumption be supplied by renewable resources.
- Judicial decisions regarding greenhouse gases– In April 2007, the U.S. Supreme Court found in Massachusetts v. EPA that CO_2 is an air pollutant under the Clean Air Act.5 For this reason the EPA has statutory authority to regulate emissions of CO_2. 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."
- A state court in Georgia has subsequently ruled that an air permit cannot be issued for a new coal-fired power plant without CO_2 emission limitations based on a Best Available Control Technology ("BACT") analysis.[6]
- Increasingly stringent federal legislative proposals that would require much more substantial reductions in greenhouse gas emissions than the proposals introduced in earlier sessions of Congress (see below).
- A 2007 resolution adopted by the National Association of Regulatory Utility Commissioners (NARUC) encouraged utility requirements to "assess and incorporate carbon-related risks in their planning and decision-making processes."[7]

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4 Carbon Principles adopted February 8, 2008. For more information see: http://www.carbonprinciples.com/

5 127 S. Ct. 1438 (2007)

6 *Friends of the Chattahoochie, Inc. and Sierra Club v. Dr. Carol Couch, Direct Environmental Protection Division, Georgia Department of Natural Resources and Longleaf Energy Associates,* LLC, Final Order in the Superior Court of Fulton County, State of Georgia, Docket No. 2008CV146398, issued on June 30, 2008.

7 NARUC, *Resolution on State Regulatory Policies Toward Climate Change,* adopted November 2007.

Federal Legislative Proposals

To date, the U.S. government has not required greenhouse gas emission reductions in the private sector. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms, such as cap and trade programs, for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as various details pertaining to offsets, allowance allocation, “safety valve” maximum allowance prices and other issues. The major federal proposals that would require greenhouse gas emission reductions that had been submitted in the 110th U.S. Congress are summarized in Table 1 below.

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

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein-Carper S.317	Electric Utility Cap & Trade Act	2007	▪ 2006 level by 2011 ▪ 2001 level by 2015 ▪ 1%/year reduction from 2016-2019 ▪ 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe S.485	Global Warming Reduction Act	2007	▪ 2010 level from 2010-2019 ▪ 1990 level from 2020-2029 ▪ 2.5%/year reductions from 2020-2029 ▪ 3.5%/year reduction from 2030-2050 ▪ 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	▪ 2004 level in 2012 ▪ 1990 level in 2020 ▪ 20% below 1990 level in 2030 ▪ 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	▪ 2%/year reduction from 2010 to 2020 ▪ 1990 level in 2020 ▪ 27% below 1990 level in 2030 ▪ 53% below 1990 level in 2040 ▪ 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	▪ Cap at 2006 level by 2012 ▪ 1%/year reduction from 2013-2020 ▪ 3%/year reduction from 2021-2030 ▪ 5%/year reduction from 2031-2050 ▪ equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	▪ 2012 levels in 2012 ▪ 2006 levels in 2020 ▪ 1990 levels by 2030 ▪ President may set further goals ≥60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	▪ 2005 level in 2012 ▪ 1990 level in 2020 ▪ 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.
Boxer-Lieberman-Warner S. 3036	Substitute for S. 2191	2008	▪ 4% below 2005 level in 2012 ▪ 19% below 2005 level in 2020 ▪ 71% below 2005 level in 2050	Economy-wide
Markey HR. 6186	The Investing in Climate Action and Protection Act	2008	▪ 2005 level in 2012 ▪ 20% below 2005 level by 2020 ▪ 80% below 2005 level by 2050	Economy-wide

The emissions levels that would be mandated by these bills that are shown in Figure 1 below, reproduced from a recent World Resources Institute analysis.[8]

[8] Version as of June 2008, available at http://pdf.wri.org/usclimatetargets_2008-06-18.pdf.

Each of the major legislative proposals that have been introduced in the 110th Congress would require far more substantial reductions in greenhouse gas emissions than would have been required by the proposals that had been introduced in Congress by the spring of 2006. For example, Figure 2 compares the emissions caps that would have been required by Senate Bill S. 2028 in the 109th Congress with the emissions levels that would be mandated under Senate Bills S. 2191 and S. 3036.

Figure 1: Comparison of Legislative Climate Change Targets in the Current 110th U.S. Congress

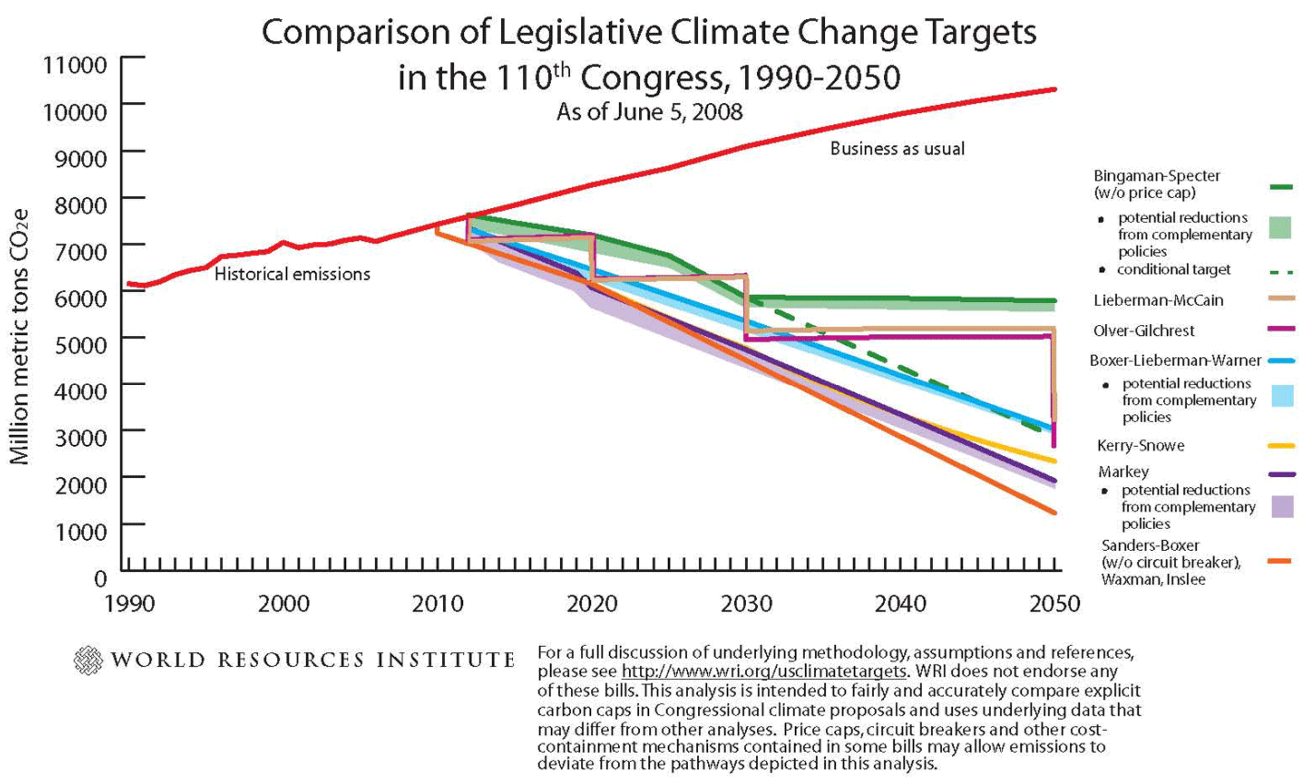
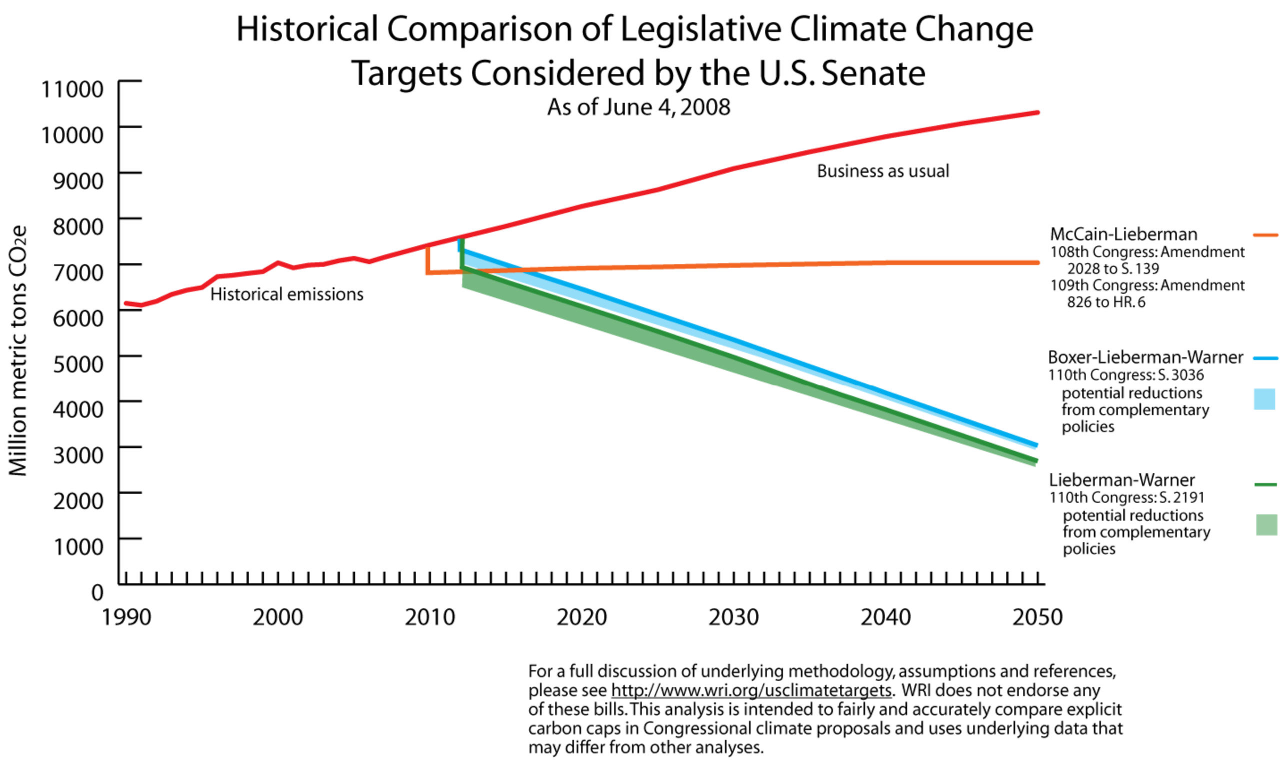


Figure 2: Historical Comparison of Legislative Climate Change Proposals in U.S. Congress



It is uncertain which, if any, of the specific climate change bills that have been introduced to date in the Congress will be adopted. The general trend is clear, however, and it would be a mistake to ignore it in long-term decisions concerning electric resources: over time the proposals in Congress are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

3. FACTORS THAT INFLUENCE CO_2 PRICES

A large number of modeling analyses have been undertaken to evaluate the CO_2 allowance prices that would result from the major climate change bills introduced in the current Congress. It is not possible to compare the results of all of these analyses directly because the specific models and the key assumptions vary. However, the results of these analyses do provide important insights into the ranges of possible future CO_2 allowance prices under a range of potential scenarios.

These analyses included the following:

- The Energy Information Administration of the U.S. Department of Energy's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).[9]
- The October 2007 Supplement to the EIA's assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.[10]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).[11]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).[12]
- The U.S. Environmental Protection Agency's ("EPA") *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).[13]
- The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).[14]
- The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).[15]
- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007).[16]
- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).[17]

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9 Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.
10 Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf
11 Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf
12 Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
13 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
14 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
15 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
16 Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf
17 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.

- *The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts, prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International, (*October 2007)[18]
- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways,* prepared by the International Resources Group for the Natural Resources Defense Council, *NRDC (May 2008)*[19]
- *The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results,* Clean Air Task Force, (January 2008).[20]
- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, (April 2008).[21]
- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM),* a report by the American Council for Capital Formation and the National Association of Manufacturers, NMA, (March 2008).[22]

The results of these and other analyses show that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. These include: the base case emissions forecast; 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; the presence or absence of a "safety valve" price; and emissions co-benefits.[23]

Based on our review of the more than 75 scenarios examined in the modeling analyses listed above we conclude that:

1. Other things being equal, more aggressive emissions reductions will lead to higher allowance prices than less aggressive emissions reductions.
2. Greater program flexibility decreases the expected allowance prices, while less flexibility increases prices. This flexibility can be achieved through increasing the percentage of emissions that can be offset, by allowing banking of allowances or by allowing international trading.[24]

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18 Available at http://www.nicholas.duke.edu/institute/econsummary.pdf
19 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf
20 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf .
21 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf ….
22 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.
23 Discussed in more detail in *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning* Synapse Energy Economics, May 2006
24 One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify. Emissions reductions must be credited only once, and offsets and trades must be associated with verifiable actions to reduce atmospheric CO_2. A generally accepted standard is the "five-point" test: "at a minimum, eligible offsets shall consist of actions that are real, surplus,

3. The rate of improvement in emissions mitigation technology is a crucial assumption in predicting future emissions costs. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in integrating carbon-free generation technologies. Improvements in the efficiency of coal burning technologies and in the costs of nuclear power plants could also be a factor.

   In general, those scenarios in the modeling analyses with lesser availability of low-carbon alternatives have the higher CO_2 allowance prices. When low carbon technologies are widely available, CO_2 allowance prices tend to be lower.

4. Complementary energy policies, such as direct investments in energy efficiency or policies that foster renewable energy resources are a very effective way to reduce the demand for emissions allowances and thereby lower their market prices. A policy scenario which includes aggressive energy efficiency and/or renewable resource development along with carbon emissions limits will result in lower allowance prices than one in which these resources are not directly addressed.

5. Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x, SO_2 and mercury. Adopting carbon reduction technology results not only in cost savings to the generators who no longer need criteria pollutant permits, but also in broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas.

6. Projected emissions under a business-as-usual scenario (in the absence of greenhouse gas emission restrictions) have a significant bearing on projected allowance costs. The higher the projected emissions, the higher the projected cost of allowance to achieve a given reduction target.

verifiable, permanent and enforceable." Still, there appears to be a benefit in terms of overall mitigation costs to aim for as much flexibility as possible, especially as it is impossible to predict with certainty what the most cost-effective mitigation strategies will be in the future. Models which assume greater program flexibility are likely to predict lower compliance costs for reaching any specified goal.

4. THE SYNAPSE 2008 CO_2 ALLOWANCE PRICE FORECASTS

The Synapse 2008 CO_2 price forecasts begin in 2013. This is a reasonable assumption since it is likely that climate change legislation will be passed by the next Congress and that the implementation of the regulatory scheme may take two years.

The Synapse Low CO_2 Price Forecast starts at $10/ton[25] in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars.

This Low Forecast is consistent with the coincidence of one or more of the factors discussed above that have the effect of lowering prices. For example, this price trajectory may represent a scenario in which Congress begins regulation of greenhouse gas emissions slowly by either:

1. including a very modest or loose cap, especially in the initial years,
2. including a safety valve price similar to the Technology Accelerator Payment in the current Bingaman-Specter Legislation (S. 1766), or
3. allowing for significant offset flexibility, including the use of substantial numbers of international offsets.

The factors could also include a decision by Congress to adopt a set of aggressive complementary policies as part of a package to reduce CO_2 emissions. These complementary policies could include an aggressive federal Renewable Portfolio Standard, more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario), and/or substantial energy efficiency investments. Such complementary policies would lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade or carbon tax policies, and would lower the expected allowance prices associated with the achievement of any particular federally-mandated goal.

The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013, in 2007 dollars, 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.

This High CO_2 Price Forecast is consistent with the occurrence of one or more of the factors identified above that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets, greater restrictions on the use of offsets, some restrictions on the availability of or the high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration, and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

There are some CO_2 price scenarios identified in recent analyses that are significantly higher than our Synapse High Price Forecast. These scenarios represent situations with

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25 Throughout this paper, emission allowance prices are quoted in dollars per ton. This should be interpreted as dollars per short ton of CO_2. Prices in the economic literature and in international trading are often quoted in dollars per metric ton of CO_2 or dollars per metric ton of carbon, but the units we use are more typical of US carbon pricing schemes.

limited availability of alternatives to carbon-emitting technologies and/or limited use of international and domestic offsets. We do not believe that the CO_2 prices characteristic of such scenarios are likely in the current political environment, given that there may potentially be avenues available for meeting likely emissions goals that would mitigate the costs to below these levels. This may change over time due to changes in technical, economic, and political circumstances, more stringent CO_2 emissions targets, and/or developments in scientific evidence and of the impacts of a changing climate.

Synapse also has prepared a Mid CO_2 Price Forecast that starts close to the low case, at $15/ton in 2013 in 2007 dollars, but then climbs to $53/ton by 2030. The levelized cost of this mid CO_2 price forecast is $30/ton in 2007 dollars, which is the midpoint between the $15/ton Low CO_2 Price Forecast and the $45/ton High CO_2 Price Forecast. The Mid CO_2 price forecast represents a scenario in which CO_2 allowance prices begin rather low, perhaps reflecting the hesitance of the U.S. Congress to impose high costs in the short run, but then climb significantly over time as federal regulation of CO_2 emissions becomes progressively more stringent.

The 2008 Synapse High, Mid and Low CO_2 Price Forecasts are shown in Figure 3 and Table 2 below:

Figure 3: Synapse 2008 CO_2 Price Forecasts

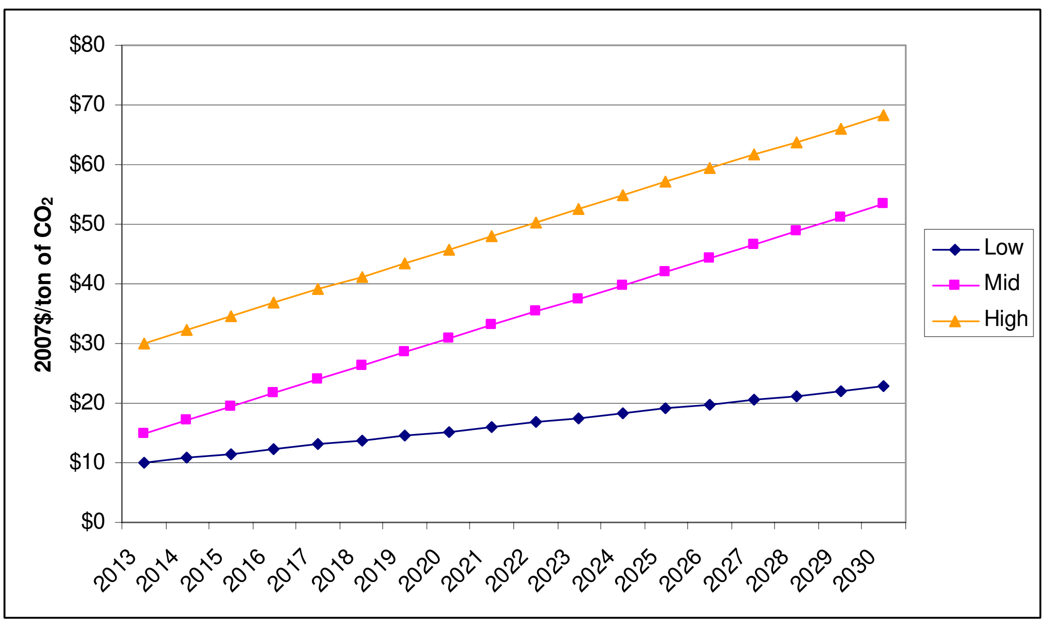

Table 2: Synapse 2008 CO_2 Price Forecasts (in 2007 dollars)

Year	Low	Mid	High
2013	$10.00	$15.00	$30.00
2014	$10.80	$17.30	$32.30
2015	$11.50	$19.50	$34.50
2016	$12.30	$21.80	$36.80
2017	$13.00	$24.00	$39.00
2018	$13.80	$26.30	$41.30
2019	$14.50	$28.50	$43.50
2020	$15.30	$30.80	$45.80
2021	$16.00	$33.10	$48.10
2022	$16.80	$35.30	$50.30
2023	$17.50	$37.60	$52.60
2024	$18.30	$39.80	$54.80
2025	$19.00	$42.10	$57.10
2026	$19.80	$44.30	$59.30
2027	$20.50	$46.60	$61.60
2028	$21.30	$48.80	$63.80
2029	$22.00	$51.10	$66.10
2030	$22.80	$53.40	$68.40

Given the significant uncertainty in the timing and design of CO_2 regulatory programs, we believe that the use of a range of CO_2 prices, such as that represented by the Synapse Low and High CO_2 Price Forecasts ($15/ton to $45/ton on a levelized basis between 2013 and 2030) is appropriate in utility resource planning.

The Synapse CO_2 price forecasts are consistent with the results of the analyses of current legislative proposals and recent forecasts by regulatory commissions and utilities. For example, Figure 4 compares the annual CO_2 prices in the Synapse Low, Mid and High Forecasts with the CO_2 prices in the scenarios examined by the EIA, EPA, MIT, and Duke University in their assessments of the proposals that have been introduced in the current U.S. Congress. The Synapse forecasts are shown in the solid red lines. A number of the analyses resulted in allowance price trajectories that were significantly higher than the Synapse forecasts. As noted earlier, however, we do not believe that the highest scenarios are realistic given the current political environment and the options available for mitigating high price impacts from carbon regulation.

Figure 4: Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Annual CO_2 Prices (in 2007 dollars)

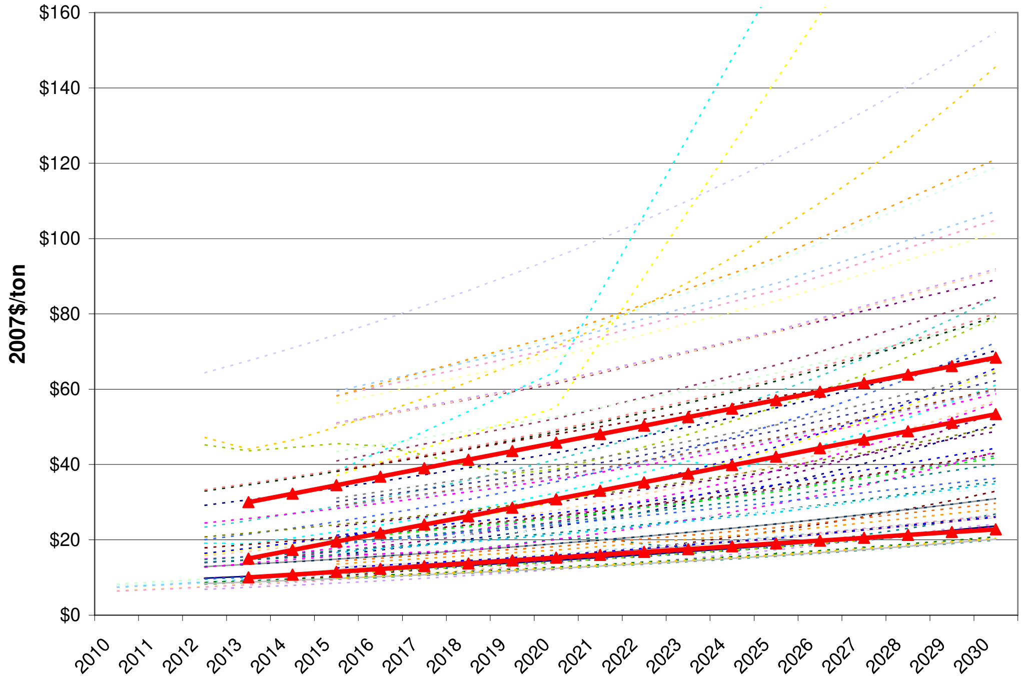

Figure 5 presents a similar comparison but in a simplified format. In Figure 5, rather than annual costs, the comparison is in terms of levelized costs for the years 2013 through 2030, also in 2007 dollars.[26] Also, in Figure 5 only the high, low, and median cases for each study are presented.

26 Synapse used a real discount rate of 7.32% for calculating levelized values. This is equivalent to 10% nominal and 2.5% inflation. We used the CPI to convert past year dollars to 2007 dollars. At the same time, we used a 2.5% inflation rate to convert future year dollars back to 2007 dollars.

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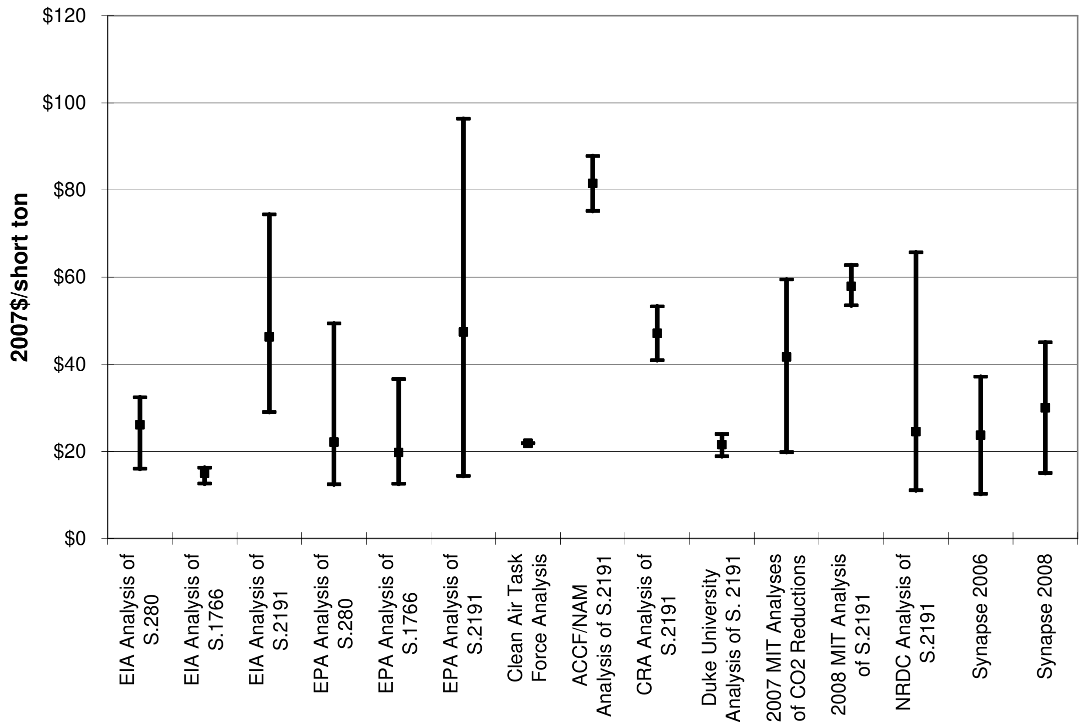
Figure 5: Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Levelized CO_2 Prices (2013-2030, in 2007 dollars)



As shown in Figure 6, the 2008 Synapse CO_2 Price Forecasts also are consistent with the ranges of CO_2 prices that an increasing number of regulatory commissions and utilities are using in electric resource planning analyses. [27]

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27 Synapse used a real discount rate of 7.32% for calculating levelized values. This is equivalent to 10% nominal and 2.5% inflation. We used the CPI to convert past year dollars to 2007 dollars. At the same time, we used a 2.5% inflation rate to convert future year dollars back to 2007 dollars.

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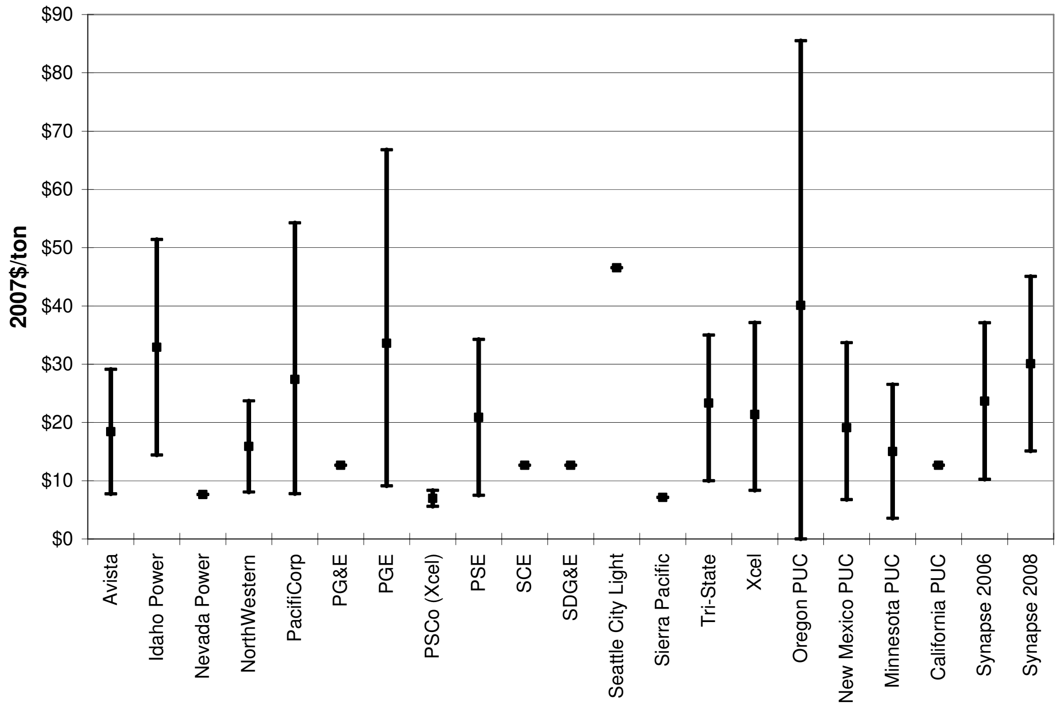
Figure 6: Synapse 2008 CO_2 Price Forecasts vs. CO_2 Prices Used by Regulatory Commissions and Utilities in Resource Planning Analyses (2013-2030, in 2007 dollars)



5. CONCLUSION

In 2006, Synapse developed an initial forecast of CO_2 allowance prices for use in electricity resource planning. In the past two years, we have seen a number of developments that have caused us to refine our expectations for the likely emission allowance costs under federal greenhouse gas regulation. More recent legislative proposals reveal a greater understanding, in Congress and among the pubic, of climate change and the emissions reductions that will be necessary to avoid dangerous climate change. As a result, long-term emission reduction targets contained in current federal proposals are more stringent than those from prior sessions, approaching the reduction levels identified by the scientific community as necessary to avoid dangerous climate change. This trend leads us to conclude that allowance prices will be higher than we projected back in 2006.

Simultaneously, today's legislative proposals reveal a more sophisticated understanding of the advantages and value of a comprehensive approach to achieving emission reductions. These proposals incorporate complementary energy policies, such as incentives for technology innovation, funds targeted to energy efficiency, restrictions on non-CCS new coal, and/or emissions performance standards, which are likely to mitigate the cost of achieving aggressive emissions goals. Further, provisions for program flexibility and trends in technological innovation hold promise to limit the price impact in the long term. Based on all of these factors, we believe our allowance price projections for the period 2013 to 2030 represent an appropriate range of values to facilitate robust decision-making for an uncertain future, in which carbon emissions will be regulated by some as-yet undefined federal regime.