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

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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
Exhibit DAS-6	*Synapse 2008 CO_2 Price Forecasts*

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.

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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

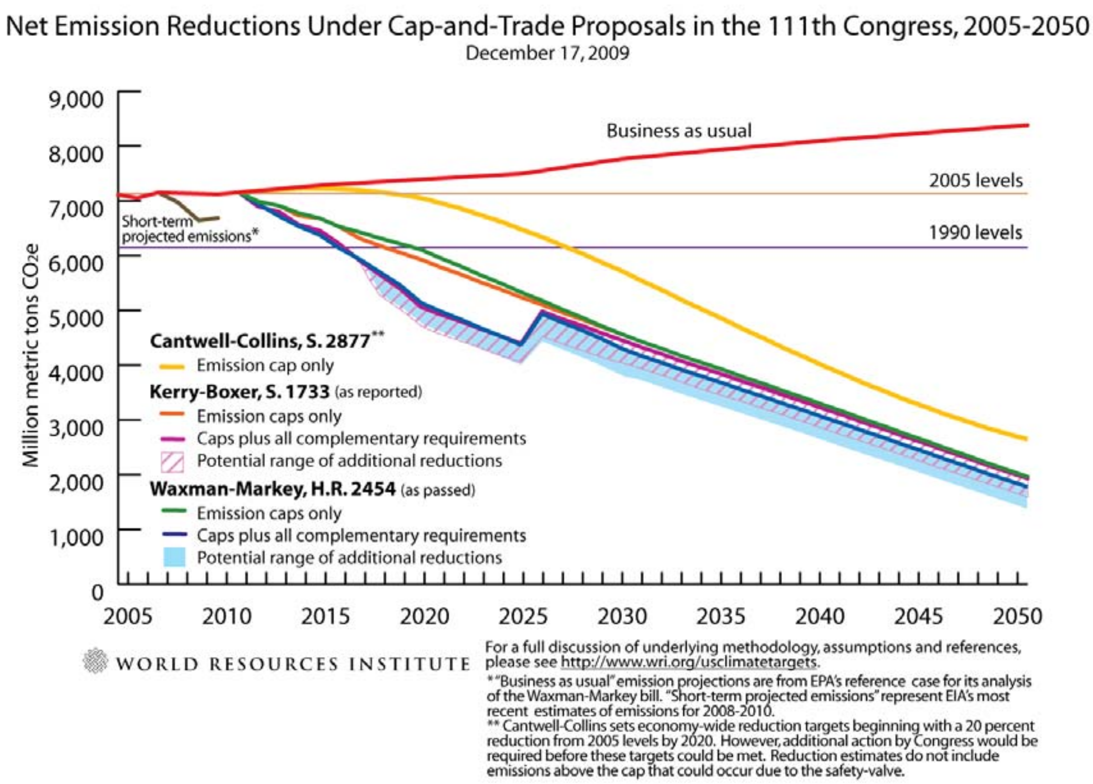
Q. What is the goal of the federal climate change legislation and policies that are being considered?

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

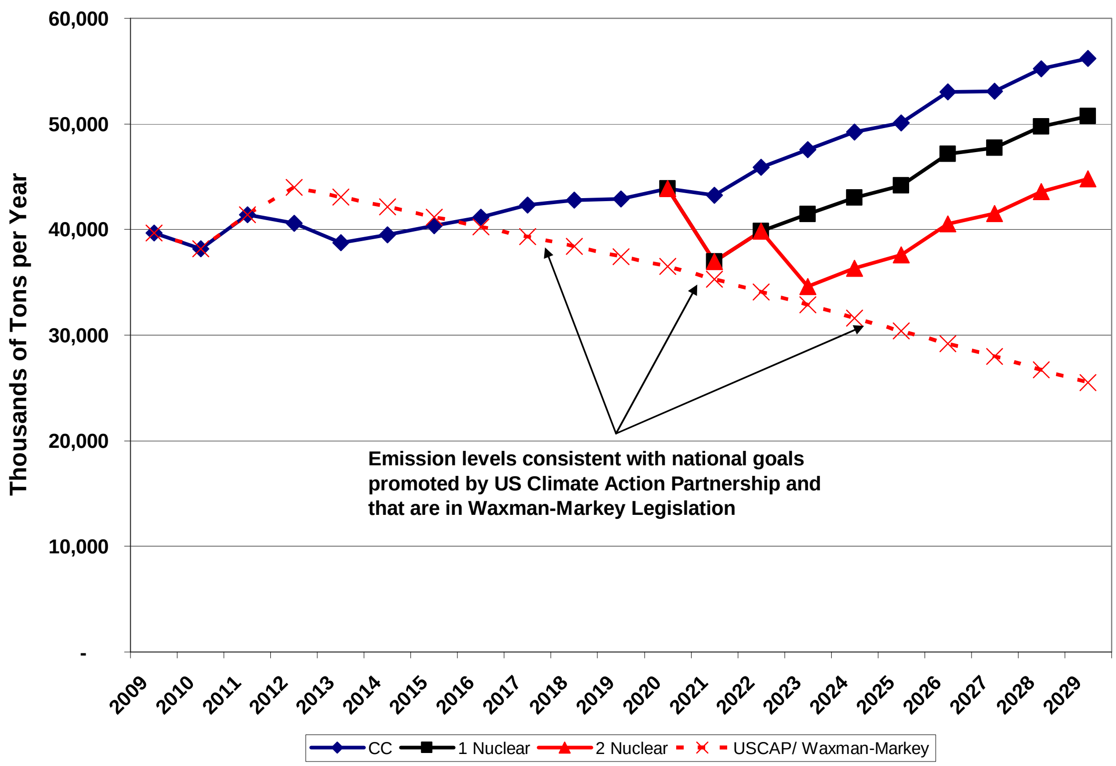
Q. What would Duke's annual CO_2 emissions be under its proposed IRP resource plan?

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.

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[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.

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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.

[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]
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> 4. Recent Natural Gas Developments
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> 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). *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.

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> 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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> *   *   *   *
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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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> *   *   *   *
>
> 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/SB12410459891270585.html.
[12] Id.

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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

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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.

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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

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[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

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

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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.

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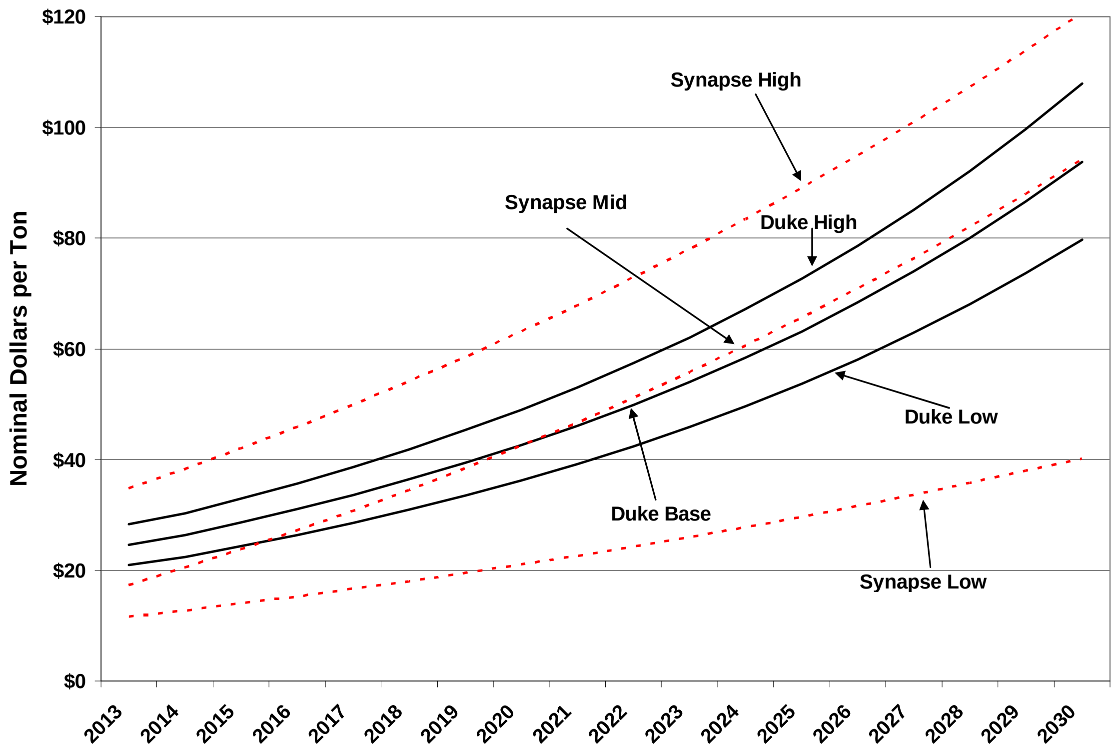
[27] Arizona State Corporation Commission website, available at http://images.edocket.azcc.gov/docketpdf/0000105829.pdf.
[28] Duke Response to SELC Informal Data Request No. 1.
[29] Duke Response to SELC Informal Data Request No. 11.

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

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[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

[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

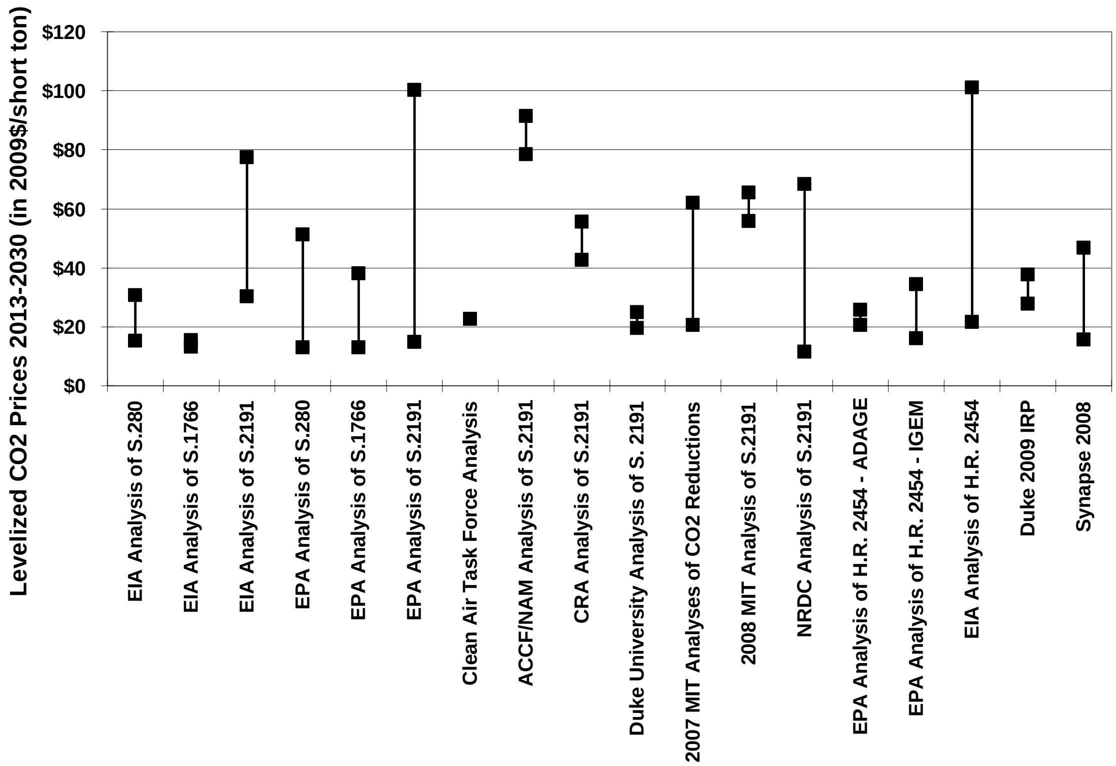

Figure 4 confirms that the range of CO_2 prices used by Duke was too narrow to reflect the potential uncertainties associated with the design and stringency of future federal regulation of greenhouse gas emissions.

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.

PUBLIC VERSION

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.

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.

PUBLIC VERSION

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.

PUBLIC VERSION

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.

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[47] Progress 2009 IRP at page 3.