THE HOWARD H. BAKER JR CENTER for PUBLIC POLICY

White Paper 2-13

Base-load Electricity from Natural Gas and Nuclear Power: The Role of Federal and State Policy

White Paper based on a symposium held by the Howard H. Baker Jr. Center for Public Policy on September 20-21, 2012

Mary R. English, Ph.D.
Baker Jr. Center Fellow for Energy and Environmental Policy

March 2013

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THE HOWARD H. BAKER JR CENTER for PUBLIC POLICY

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Howard H. Baker Jr. Center for
Public Policy
1640 Cumberland Avenue
Knoxville, TN 37996-3340

bakercenter.utk.edu
865.974.0931
bakercenter@utk.edu

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Matthew N. Murray, PhD

Director

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Howard H. Baker, Jr.

<u>Acknowledgments and Disclaimers</u>

The symposium on which this paper is based was made possible by the symposium sponsors – the Tennessee Valley Authority, America's Natural Gas Alliance, and Spectra Energy Corporation – as well as the Howard H. Baker Jr. Center for Public Policy, which also supported preparation of this paper. The paper draws upon the speakers' presentations and the participants' discussion at the symposium. (For the presentation powerpoints, see http://bakercenter.utk.edu/symposium-agenda/.) All of the symposium speakers, as well as the session chairs and members of the symposium planning team, had an opportunity to review a draft of the paper. The author acknowledges with thanks the vital guidance and help of the symposium planning team, the wealth of knowledge imparted during the symposium, and the suggestions made later regarding the paper. The paper does not necessarily represent the views of the Baker Center or the symposium sponsors, planning team members, chairs, speakers, or other participants.

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Executive Summary

In the coming decades, electricity generation in the United States may rely to a large extent on natural gas and nuclear power. This possibility motivated a symposium held by the Howard H. Baker Jr. Center for Public Policy on September 20-21, 2012.

The symposium featured 18 nationally- and regionally-known speakers who collectively provided a comparative analysis of the technical, economic, environmental, human health, safety, and national security attributes of these two electricity sources within the context of current and prospective federal and state policies. The comparative analysis drew upon four illustrative case examples – two gas-fired and two nuclear; two from the public sector and two from the private sector:

- The John Sevier combustion-turbine combined-cycle (CTCC) plant of the Tennessee Valley Authority (TVA) in northeastern Tennessee
- The Sutton CTCC plant of Duke Energy near Wilmington, North Carolina
- TVA's possible small modular reactor project at its Clinch River Site in Oak Ridge, Tennessee
- The Westinghouse AP1000 project of the Southern Company at Plant Vogtle Units 3 and 4 in eastern Georgia

Symposium attendance was by invitation only, with a total of about 70 participants from the electric power industry, regulatory agencies, research institutions, and other non-governmental organizations. The Tennessee Valley Authority was the symposium's lead sponsor; America's Natural Gas Alliance and Spectra Energy Corporation were contributing sponsors. The white paper prepared following the symposium, based on its presentations and discussions, is synopsized below.

Demand for electricity is being tempered by energy efficiency improvements, and renewable energy sources are increasingly viable. Nevertheless, large-scale electricity generation will be needed for the foreseeable future. With growing concerns about greenhouse gases and hazardous as well as conventional air pollutants, coal has fallen out of favor. Its traditional role as the mainstay of electricity generation is shrinking. What will take up the slack? Gas-fired plants and nuclear power plants are the two most likely candidates.

Electric utilities – investor-owned or publicly-owned – must grapple with many future uncertainties: uncertainties concerning customer demand, federal and state regulations, fuel costs, and power supply technologies. They must do so while contending with important internal imperatives: the need to curb costs, to plan far ahead, and to assure that their electricity generation systems are reliable and flexible. Balanced portfolios are seen as one important response to these challenges. The portfolios of all of the electric utilities that were represented at the symposium – the Tennessee Valley Authority, Southern Company, and Duke Energy – include plans for new natural gas and nuclear power.

New gas-fired power plants and new nuclear power plants have dramatically different advantages and disadvantages. Advanced combustion-turbine combined-cycle (CTCC) plants require modest capital investments, are fairly easy to get permitted, have short lead times, and offer operational flexibility. Their biggest potential drawback is their reliance on natural gas. Historically volatile, natural gas prices have become lower and more stable with plentiful domestic shale gas produced by hydraulic fracturing, or "fracking." Fracking raises environmental concerns, however, especially about water contamination and consumption. In addition, fugitive methane emissions during natural gas production and distribution could offset the climate change advantage that gas-fired plants appear to have over coal-fired plants. There also is no certainty that natural gas prices will remain low.

Advanced nuclear power plants – either large reactors or small modular reactors (SMRs) – are technically much better than the reactors of the 1970s and 1980s, due partly to extensive R&D support by the federal government. New nuclear power plants still face large hurdles, however: high capital costs, exacting regulations, and long lead times. And, while advanced nuclear power plants – especially SMRs – have some potential for operational flexibility, they are not as nimble as CTCC plants. Climate change benefits are the biggest advantage nuclear power offers. Long-term storage and disposal of spent nuclear fuel remains a conundrum.

Federal and state policies – policies concerning "carrots" (e.g., grants, tax credits, loan guarantees) as well as "sticks" (e.g., regulations, taxes, fees) – can affect the comparative advantages of an electricity generation technology. Policy differences between new gas-fired plants and new nuclear power plants are evident, particularly regarding the size of both the carrots and the sticks.

While the symposium discussion of public policies affecting gas-fired plants and nuclear power ranged broadly, it nevertheless prompted some similar strands of comments. Two broad themes, framed here as questions, cropped up: (1) should the government avoid "picking winners and losers"? and (2) should the government undertake long-range planning for electricity generation and transmission? These questions cannot be answered conclusively: ultimately, their answers depend on individual, deeply-held beliefs and values. In addition, however, five more targeted suggestions emerged:

- Develop regulations that
    - incorporate forward-thinking analysis,
    - take into account multiple pollutants in multiple media,
    - allow adequate lead times for utilities to prepare for regulatory changes, and
    - reduce uncertainty while increasing flexibility.
- Recognize that capital cost accounting practices affect electricity generation choices.
- Think proactively about the effects of severe and persistent droughts on water supplies for fuel production and electricity generation.
- Take into account the power generation implications of improvements to electricity transmission and distribution systems.
- Optimize the possibilities of demand-response programs.

Consensus on these suggestions was not sought: the purpose of the symposium was to foster thoughtful analysis and exchange. Nevertheless, it is hoped that these suggestions and the white paper as a whole will be useful to policymakers within government and the electric utility industry, as they strive to ensure that the nation's electricity generation, transmission, and distribution systems are sustainable, reliable, and affordable. It is a task of paramount importance.

Contents

Introduction

Demand for electricity continues to grow. Energy efficiency measures are helping to rein in demand, and renewable energy sources such as wind and solar power are coming to the fore. Nevertheless, the United States is likely to need large-scale generation of base-load electricity for the foreseeable future.

For the past 60 years, coal has been the work horse of base-load electricity in the United States. But with aging plants, tougher regulation of criteria air pollutants such as sulfur dioxide and nitrogen oxide, attention to hazardous air pollutants such as mercury, and curbs on carbon dioxide emissions, coal is falling out of favor. Retirements of coal-fired electricity generating units (EGUs) are at record highs (U.S. Energy Information Administration (EIA), July 27, 2012, Today in Energy,"27 gigawatts of coal-fired capacity to retire over the next 5 years" http://www.eia.gov/todayinenergy/detail.cfm?id=7290).

Natural gas and nuclear power are the two likely candidates to take coal's place, but their roles in future electricity generation are by no means certain. Utilities face a host of questions about what the future will bring concerning, for example, demand for electricity, the regulation of greenhouse gases, the cost of fuels such as natural gas, and improvements in energy efficiency, renewable energy, electricity storage, distributed energy, smart grids, and megagrids. It is within this fog of uncertainty that an electric utility must make major investment decisions about its evolving fleet of power plants.

In consultation with senior officials at the Tennessee Valley Authority and with the guidance of a 14-member planning team, the Howard H. Baker Jr. Center for Public Policy held a symposium on September 20-21, 2012, to consider how federal and state policies affect the development of new base-load capacity from natural gas and nuclear power. The symposium featured 18 speakers who collectively provided a comparative analysis of the technical, economic, environmental, human health, safety, and national security attributes of these two electricity sources within the context of current and prospective federal and state policies. The comparative analysis drew upon four illustrative case examples – two gas-fired and two nuclear; two from the public sector and two from the private sector:

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Symposium attendance was by invitation only, with a total of about 70 participants from the electric power industry, regulatory agencies, research institutions, and other non-governmental organizations. The Tennessee Valley Authority was the symposium's lead sponsor; America's Natural Gas Alliance and Spectra Energy Corporation were contributing sponsors.

Natural gas and nuclear power were the thematic focus of the symposium, and the southeastern United States, especially the Tennessee Valley region, was its geographic focus. Nevertheless, the presentations and participant discussions were wide-ranging, considering a broad range of national factors and implications. The purpose of this paper is to distill the essence of those presentations and discussions. The paper does not represent a consensus viewpoint of the symposium participants: the symposium was meant to trigger analysis and thoughtful exchange, but consensus was not sought. The paper also does not necessarily represent the views of the symposium sponsors or the Baker Center.

The paper has three sections: first, a brief discussion of the context within which important electric utility decisions are made; second, a review of the key comparative issues with base-load electricity from natural gas and from nuclear power; and third, a synopsis of cross-cutting themes concerning public policies that crystallized during the symposium. Appendix A provides short write-ups of the four case examples. The symposium program – including the agenda, a list of the planning team members, and short biographies of the session chairs and speakers – can be found in Appendix B.

Most major electric utilities will have a mix of supply-side sources. Making decisions and fostering widespread understanding about that mix will require nuanced, objective analysis. Similarly, the legislative and executive branches of federal and state governments have an array of energy policy choices. Making decisions about public policies should be based on objective analysis, including analysis of a policy's broad, long-term consequences. It is hoped that this paper will help both electric utilities and public policymakers in the difficult decision-making ahead.

I. Contextual Factors Affecting Electric Utilities

Electric utilities – investor-owned or publicly-owned – must grapple with many future uncertainties: uncertainties concerning customer demand, federal and state regulations, fuel costs, and power supply technologies. They must do so while contending with important internal imperatives: the need to curb costs, to plan far ahead, and to assure that their electricity generation systems are reliable and flexible. Balanced portfolios are seen as one important response to these challenges.

Many of the contextual factors that affect federal and state policymakers are widely recognized: for example, the dictates of re-electability, terms of office, and shifting budget authorizations and appropriations. The contextual factors that affect electric utilities are less well-known and were mentioned often during the symposium. Two sets of key contextual factors – one external to the electric utility industry, the other internal – are summarized below.

It should be noted, though, that a key contextual factor is absent from this discussion: the views of the public. These include views about not only electricity rates but also electricity generation, including perceptions regarding the risks and benefits of different supply-side sources and preferences regarding demand-side management measures. Assessing public perceptions and preferences was not on the symposium agenda because the topic was too large to be covered in the time available. Nevertheless, the views of members of the public are potentially important in shaping the decisions of utilities and public policymakers.

External context: coping with uncertainties.

- **Demand uncertainty.** The growth rate of electricity demand has slowed dramatically in the past 60 years. In the 1950s, the annual rate was nearly 10 percent; by the first decade of this century, it was under 1 percent (EIA, Annual Energy Outlook 2012, June 25, 2012). Nevertheless, demand for electricity still is growing, and over a long time frame even tepid growth rates will compound to substantial levels of demand (James, symposium presentation).

  Being reasonably sure of demand growth over long time frames provides only a modest measure of certainty, however. In shorter time frames, the scale of electricity demand is difficult to predict. On the one hand, it is affected by demand-decreasing factors such as economic downturns and energy efficiency improvements; on other hand, by demand-increasing factors such as population growth and new power-hungry technologies, including grid-dependent modes of transportation. The timing of demand also is difficult to predict. For example, will peak power continue to be required at certain times of day, or can the diurnal demand curve be smoothed? Estimating the scale and timing of future demand is necessary when planning future rates, revenue, and supply-side investments.

- **Regulatory uncertainty.** Electric utilities are subject to a variety of federal and state laws and regulations, but environmental laws and regulations probably pose the greatest uncertainty, especially in the short run. It can be assumed that a transition to cleaner energy will be required in the long run. But what will be the pollutants of greatest regulatory concern, how much must they be reduced, and when?

Regulations are grounded in laws, which can be amended. Laws rarely specify in detail how their statutory mandates are to be executed; the details are spelled out in regulations. These detailed regulations, which may be based on protracted studies and negotiations, can take years to be promulgated. (The regulation of mercury emissions from coal- and oil-fired electric utilities is a case in point.) When a final regulatory rule is issued, it may be the target of lawsuits by utilities as well as others that lead to court decisions to uphold, remand, or vacate the rule. Court decisions can be appealed to higher courts, further protracting the regulatory process. Long delays may benefit an electric utility, but they contribute to the uncertain context within which the utility's decisions are made.

- **Fuel cost uncertainty.** The importance of fuel prices to electric utilities is demonstrated by the recent, dramatic switch from coal-fired to gas-fired plants. While the price stability of coal historically has benefited both sellers and buyers, this price rigidity is a disadvantage for coal-fired plants when demand in the electric power sector is relatively stagnant and gas prices are low or falling rapidly (Kaplan, symposium presentation).

  In the absence of long-term price contracts, fluctuations in supply and demand can substantially affect a utility's fuel costs, for better or for worse. Nationally, the new abundance of a fuel such as natural gas can drive its price down significantly in the short term, but super-low prices can lead to adverse effects on fuel production or to increased demand from various sectors – not just the power sector – and to higher prices. In recent months, U.S. natural gas electric power prices have gone up slightly from their 10-year low of $2.79 per Mcf (thousand cubic feet) in April 2012 (EIA, U.S. Natural Gas Electric Power Price http://www.eia.gov/dnav/ng/hist/n3045us3m.htm). Where they will go in the future remains to be seen. While they may be less volatile than they historically have been, there are many unknowns – for example, the extent of recoverable natural gas reserves and the effects of environmental regulations on shale gas production (Krupnick, symposium presentation).

  Global demand may affect domestic prices as well. New power plants in nations with rapidly developing economies, such as China, create new demand for energy fuels. In some cases, these fuels may be domestically produced; alternatively or in addition, they may be exported from countries such as the United States. In the latter case, the price of that fuel in the exporting country is likely to be affected. Natural gas is likely to be exported from the United States to only a limited extent, however, as reserves of shale gas are tapped in areas such as Southeast Asia, Australia, and Europe (Krupnick, symposium presentation).

- **Unanticipated power supply opportunities.** As demonstrated by the rapid conversion to gas-fired combined-cycle plants with the advent of abundant shale gas, opportunities can arise that, in the long time frame of power supply investments, are difficult to anticipate. Sometimes these opportunities arise mainly through private sector activity; sometimes they are nurtured by government tax incentives and research funds – for example, production tax credits for low-carbon electricity sources; research funds for large-scale, economically feasible electricity storage technologies that enable greater use of intermittent power sources such as wind and solar. Regardless of its origin, if a new opportunity offers significant advantages over existing power supply technologies, a utility may invest in it directly or acquire it through purchased power arrangements. While unexpected opportunities are welcome, they complicate planning for major supply-side investments.

Provisions of the 1978 Public Utility Regulatory Policies Act (PURPA), the 1992 Energy Policy Act, and rules of the Federal Energy Regulatory Commission (FERC) further complicate the power supply picture. PURPA required utilities to purchase power from independent companies that could produce it for less than the utility could. The 1992 Energy Policy Act encouraged wholesale power competition, and subsequent rules by FERC opened up transmission lines to all generators equally. The effects of these regulatory changes have altered the world that existed for electric utilities for more than 40 years, from the mid-1930s until the late 1970s. Once predictable, that world is now much more fluid.

Internal context: the imperatives of cost constraints, long time frames, and system reliability and flexibility.

- **Cost constraints.** Major electric utilities must try to keep rates down but sometimes must fund billion-dollar projects. For TVA, this challenge is heightened by its debt ceiling, which was set at $30 billion by Congress in 1979 and has remained unchanged. A federal corporation, TVA initially had all of its operations funded by congressional appropriations. This practice ended for its power program in 1959, and by 1999 appropriations for its environmental stewardship and economic development programs had been phased out. Now fully self-financed, TVA funds its operations primarily through electricity sales and financing arrangements.

  Investor-owned utilities, while not constrained by legislatively-set debt ceilings, nevertheless must answer to shareholders as well as ratepayers, and – in all but deregulated states – to regulatory commissions. In addition to shareholder investments, the funding of investor-owned utilities comes primarily through electricity sales and financing arrangements.

- **Long time frames.** Large-scale investments in new electricity generating units (EGUs) entail long time frames. Planning and construction may, depending upon the EGU, take a decade or more. Once the EGU is operational, unforeseen problems may surface, but sometimes not for a decade or more. To date, most large-scale EGUs have been planned to operate for about 60 years. It is within this time frame, looking forward nearly three-quarters of a century, that decisions are made regarding an electric utility's major new base-load electricity sources. As David Sorrick with Duke Energy commented in Session I of the symposium, "We anticipate that we will have to replace our entire fleet by 2050. What should that fleet look like, and how do we bridge to that future? In other words, we are operating our current fleet, building our next fleet, and planning for the fleet after that" (Sorrick, symposium presentation).

- **System flexibility and reliability.** The system requirements of a utility are becoming increasingly stringent. As just one example, the renewable portfolio standards of some states have required utilities to incorporate renewable supply-side sources into their generation mixes. Some of these sources (e.g., wind, solar) are intermittent, creating a need for more nimble switching among generation modes and more reserve generation (James, symposium presentation).

  In addition, in a world where a vast array of technologies performing essential services runs on electrical power, electricity is much more than a convenience. It is a necessity. Grid reliability has become a top national priority, as indicated by a provision in the 2005 Energy Policy Act providing for designation of a non-governmental "electric reliability organization" to develop and enforce mandatory reliability standards in the United States. In 2006, the North American Reliability Corporation received this designation from FERC.

Balanced portfolios: a piece of the puzzle.

The importance of reliability in the face of unpredictable events contributes to the need for large electric utilities to have balanced portfolios of EGUs. So do the different attributes, positive and otherwise, that different types of EGUs bring to the utility's system. A primary goal of an electric utility is to assure the long-term sustainability of its fleet of EGUs as that fleet evolves to meet changing needs (James, symposium presentation); a balanced portfolio may be the best way to achieve that sustainability.

Achieving a balanced portfolio was a major factor shaping TVA's 2010 Integrated Resource Plan (Hoagland, symposium presentation), and TVA has begun to move in this direction: in 2007, its generated electricity was 56 percent coal, 26 percent nuclear, 12 percent purchased power , 6 percent hydro, 0 percent gas, and 0 percent renewables; in 2013, it is forecast to be 35 percent coal , 31 percent nuclear, 11 percent gas, 10 percent purchased power, 10 percent hydro, and 3 percent renewables (Kosnaski, symposium presentation). A similar shift toward more diversified portfolios can be seen with other major electric utilities such as Duke Energy and the Southern Company.

II. <u>*Base-load Electricity from Natural Gas and Nuclear Power: Key Comparative Issues*</u>

New gas-fired power plants and new nuclear power plants have dramatically different advantages and disadvantages.

Advanced combustion-turbine combined-cycle (CTCC) plants require modest capital investments, are fairly easy to get permitted, have short lead times, and offer operational flexibility. Their biggest potential drawback? Their reliance on natural gas. Historically volatile, the price of natural gas has become much lower and more stable with plentiful shale gas produced domestically by hydraulic fracturing, or "fracking." Fracking raises environmental concerns, especially about water contamination and consumption. In addition, fugitive methane emissions during natural gas production and distribution could offset the climate change advantage gas-fired plants now appear to have over coal-fired plants. There also is no certainty that natural gas prices will remain low.

Advanced nuclear power plants – either large reactors or small modular reactors (SMRs) – are technically much better than the reactors of the 1970s and 1980s, due partly to extensive R&D support by the federal government. They still face large hurdles, however: high capital costs, exacting regulations, long lead times. And, while advanced nuclear power plants – especially SMRs – have some potential for operational flexibility, they are not as nimble as a CTCC plant. Climate change benefits are the biggest advantage nuclear power offers. Long-term storage and disposal of spent nuclear fuel remains a conundrum.

During symposium discussions, twelve areas of differencebetween new gas-fired plants and new nuclear power plants stood out: (1) regulatory hurdles, (2) safety imperatives, (3) lead times, (4) capital costs (including financing costs), (5) government incentives, (6) electricity generation capacity factors, (7) fixed and variable operation and maintenance costs (including fuel costs), (8) operational flexibility, (9) climate change impacts, (10) other adverse environmental impacts (near term), (11) other adverse environmental impacts (distant future), and (12) security risks. While the focus of the symposium was on the power plant itself, some "upstream" and "downstream" factors also were considered and contribute to these differences.

The differences between new gas-fired and nuclear power plants in each of these twelve areas are crudely summarized in the table below. In considering this table, three points should be kept in mind:

- **First, the table is a post-facto summary.** It was not used at the symposium as an evaluation tool: we did not attempt to come to a common understanding of the relative merits of the technologies in each of these areas.

- **Second, a comparative evaluation of these technologies would require weighting the twelve areas according to their relative importance.** Relative importance is a value judgment; it also could change with changing circumstances.

- **Third, the text that follows fleshes out the crude assessments below and may lead the reader to different conclusions.**

Table 1. Comparision of advanced combustion-turbine combined-cycle plants and advanced nuclear power plants.

Key Areas of Difference	Advanced CTCC plants	Advanced nuclear power plants: large reactors	Advanced nuclear power plants: SMRs*
Regulatory hurdles	Low	High	High
Safety imperatives	Low	High	High to moderately high
Lead times	Short	Long	Potentially moderate
Capital costs (incl. financing costs)	Low	High	High to moderately high
Government incentives	Moderate	Large	Large
Capacity factors	Good	Excellent	Excellent
Fixed and variable O& M costs(incl. fuel costs)	Currently low but potentially unstable	Moderate and predictable	Moderate and predictable
Operational flexibility	Good	Poor	Some potential
Climate change impacts	Uncertain	Low	Low
Other environmental impacts (near term)	Uncertain	Moderately low	Potentially low
Other environmental impacts (distant future)	Low	Potentially high	Potentially high
Security risks	Low	Moderate to high	Moderate

*Several of the assessments shown here for small modular reactors are speculative since no SMR has yet been licensed or constructed in the United States.

(1) Regulatory Hurdles

Regulatory hurdles vary by both the type of electric utility – publicly-owned or investor-owned – and the type of generation facility. Publicly-owned electric utilities (utilities operated by government corporations or membership cooperatives) must comply with many regulations, but their decisions about rates, new generation, etc. are made by their own governing boards. In contrast, except in states with electricity deregulation – 15 states as of 2010, mainly in the Northeast (EIA, September 2010, Status of Electricity Restructuring by State http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html) – investor-owned electric utilities must answer to state commissions, often called "public utility commissions" (PUCs), which have the authority to review and approve a utility's rates and integrated resource plans. In addition, before constructing a new generation facility, an investor-owned electric utility typically must obtain PUC certification that the facility is in the public interest. Certification is required regardless of the plant’s fuel source; in this way, the regulation of investor-owned nuclear power plants and gas-fired plants is similar. There the regulatory similarities end.

The U.S. Nuclear Regulatory Commission (NRC) regulates the construction and operation of all commercial nuclear power plants, publicly-owned or investor-owned. As a federal regulatory agency, an Environmental Impact Statement (EIS) is required under the National Environmental Policy Act (NEPA). The EIS is shaped by the statement of purpose and need, which sets the framework for reasonable alternatives to the proposed action that must be considered in the EIS (Cushing, symposium presentation). The final EIS is a key step – one of several – before NRC issues a construction permit and operating license for a nuclear power reactor. Several states have enacted legislation placing a moratorium on new nuclear power plants. Otherwise, state involvement in nuclear power plant regulation is minimal but does include regulation of water withdrawals and releases, including thermal limits on released water.

In contrast, gas-fired power plants – publicly-owned or investor-owned – typically are subject to state environmental regulation but not to direct federal scrutiny. The relevant state environmental regulations mainly consist of rules implementing the federal Clean Air Act and the Federal Water Pollution Control Act (commonly called the Clean Water Act), which are handed down by the U.S. Environmental Protection Agency to state programs with delegated permitting authority. While air and water regulations are non-trivial, they are not a huge challenge for gas-fired plants. Not so for coal-fired plants. With increasingly stringent air quality regulations, utilities are faced with difficult decisions about whether to install new pollution controls on their aging coal-fired units, mothball them, or retire them completely.

(2) Safety Imperatives

While both gas-fired plants and nuclear power plants must include measures to assure worker and public safety, the bar is much higher for nuclear power plants because of the possibility of uncontrolled emission of radiation. Operator error and equipment failure have long been a focus of nuclear plant safety, but with recent events such as the March 2011 tsunami-triggered disaster at the Fukushima Daiichi plant in Japan, heightened attention is being paid to accidents that unfold because of earthquakes, flooding, prolonged power outages, etc.

The new generation of nuclear power reactors – either large reactors such as the Westinghouse AP1000 (see Appendix A, Case 4) or small modular reactors such as the mPower SMR (see Appendix A, Case 3) – are designed in part to ensure reactor safety under a variety of accident scenarios. Simplified, standardized designs are central to many of the new reactor concepts. While the result may in the long term increase safety and lower cost, new designs are expensive. For example, it has been estimated that the detailed design and engineering of a new SMR technology could cost a billion dollars (Rosner and Goldberg, November 2011, “Small Modular Reactors: Key to Future Nuclear Power Generation in the U.S.” https://epic.uchicago.edu/sites/epic.uchicago.edu/files/uploads/SMRWhite_Paper_Dec.14.2011copy.pdf).

Even with technology improvements, however, challenges remain for nuclear power safety. The safety of a nuclear power plant depends not only on technology, training, and corporate culture but also on the adequacy of external regulation, including on-going regulatory enforcement. Safety problems increase with older reactors if the integrity of key components becomes compromised (Lochbaum, symposium presentation).

In addition, lacking the federal repository promised in the 1982 Nuclear Waste Policy Act, utilities must store their spent fuel on-site indefinitely. Spent fuel assemblies are put in large pools of water to allow their heat to dissipate. After five years they are cool enough to be transferred to dry cask storage, but this transfer is not required.The NRC believes that both spent fuel pools and dry casks provide adequate protection of the public health and safety and the environment (NRC, Spent Fuel Storage in Pools and Dry Casks http://www.nrc.gov/waste/spent-fuel-storage/faqs.html). Others such as the Union of Concerned Scientists – arguing that spent fuel pools are more vulnerable to malfunctions, natural disasters, and terrorist attacks – advocate moving spent fuel assemblies to dry cask storage as soon as the five-year cooling period is up (Union of Concerned Scientists, Safer Storage of Spent Nuclear Fuel (http://www.ucsusa.org/nuclear_power/nuclear_power_risk/safety/safer-storage-of-spent-fuel.html).

Under the Price-Anderson Nuclear Industries Indemnity Act of 1957, nuclear power plants are required to have federal liability protection in the event of an accident that causes injury or property damage to the public. No other type of electricity generation plant has this requirement. The arrangement under the Price-Anderson Act is a combination of private insurance and industry self-insurance. One criticism of the arrangement is that premiums are not adjusted for the relative safety of the reactor unit, which may tend to discourage safety upgrades (Lochbaum, symposium presentation). Another criticism of the Price-Anderson Act is that, because it caps the liability of a nuclear power plant licensee in the event of an accident (NRC, Fact Sheet on Nuclear Insurance and Disaster Relief Funds http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/funds-fs.html), it may reduce the licensee's incentive to avoid large losses.

(3) Lead Times

In the 1970s and 1980s, the licensing process for nuclear power plants was protracted and uncertain. The U.S. Nuclear Regulatory Commission addressed this shortcoming two decades ago with a streamlined process that enables (but does not require) early site approval and combined construction and operating licenses as well as certification of standardized designs. With a resurgence of interest in nuclear power, the process is only now being put to the test. Plant Vogtle Units 3 and 4 (see Appendix A, Case 4) are the first to use it. Their state (Georgia Public Services Commission) and federal (NRC) regulatory processes took a total of 7 years, from 2005 to 2012. Completing construction and starting commercial operation will take another 4 years or so.

If TVA goes forward with its SMR project at its Clinch River site (see Appendix A, Case 3), it foresees a timetable of eight years between license application and commercial operation. This schedule is more expeditious than the typical nuclear power plant, and – since the Clinch River SMR project is a "first of its kind" – the process will likely take longer than it would if the SMR were a well-established technology. An SMR's schedule still can't compete with that of a gas-fired plant, however.

Due to lower technological and regulatory demands, the march from project initiation to commercial operation is relatively fast for a gas-fired plant. If an existing electricity generation site is used, as was the case with the TVA's John Sevier Plant and Duke Energy's Sutton Plant (see Appendix A, Cases 1 and 2), the lead time can be as short as three to four years.

(4) Capital Costs (including financing costs)

The capital costs of new gas-fired power plants are far lower than those of new nuclear power plants. The capital cost of TVA's gas-fired John Sevier plant, with 880 MW of capacity, was about $800 million; that of Duke Energy's gas-fired Sutton plant, with 625 MW of capacity, was about $600 million (see Appendix A, Cases 1 and 2). These capital costs are fairly typical for today's advanced combined-cycle gas-fired plants.

In contrast, the estimated capital cost of Plant Vogtle Units 3 and 4, with a total of 2,200 MW of capacity, is about $13 billion including financing costs (see Appendix A, Case 4). Financing costs are a big-ticket item with new nuclear power reactors: given the billions of dollars that get tied up in the project, longer construction times before commercial operation can mean much higher financing costs. The shorter construction times anticipated with an SMR and the greater phase-in potential of an SMR project give it a significant financing cost advantage over a nuclear power plant with large reactors (see Appendix A, Case 3). According to one analysis, the overnight capital cost (capital cost without financing and escalation costs) of a hypothetical project involving six 100-MW SMRs could be about $3 billion (Rosner and Goldberg, November 2011).

(5) Government Incentives

Advanced gas-fired turbines have benefited from federal research funds, especially through research sponsored by DOE's National Technology Research Laboratory. This research extends to natural gas supplies. In November 2012, DOE announced that fifteen projects would receive a total of $28 million in federal funds for research regarding natural gas production from shales and tight sands and ways to minimize its adverse environmental effects (DOE, November 28, 2012, Research Projects Addressing Technical Challenges to Environmentally Acceptable Shale Gas Development Selected by DOE http://www.fossil.energy.gov/news/techlines/2012/12058-DOE_Selects_RPSEA_Projects.html).

Federal investments in natural gas supplies and technologies for generating electricity are not large, however, when compared with federal investments over the years in nuclear power. (See, e.g., DOE, October 31, 2001, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010*, Volume II, Chapter 2 http://energy.gov/sites/prod/files/NTDRoadmapVolII.pdf) The 2005 Energy Policy Act was especially important to today's nuclear power industry. It made possible a number of incentives for advanced nuclear power plants, including production tax credits, loan guarantees, federal funding for technology research and development, and protections against construction cost overruns due to regulatory delays (Nuclear Energy Institute, October 2010 http://www.nei.org/resourcesandstats/Documentlibrary/New-Plants/factsheet/licensingnewnuclearpowerplants). Without these provisions, it is questionable whether advanced nuclear power projects would be moving forward at this point (see Appendix A, Cases 3 and 4).

(6) Electricity Generation Capacity Factors

The "capacity factor" of an EGU is a measure of its actual output over a period of time compared with its theoretical output if it had operated at continuous full power during that period. Assuming the EGU is used for base-load electricity, its capacity factor is mainly affected by planned and unplanned outages.

Nuclear power currently has the highest capacity factor of all electricity sources. According to EIA, the average capacity factor of nuclear power plants in the United States in 2009 was 90.3 percent (EIA, April 2011, *Electric Power Annual 2009* http://www.eia.gov/electricity/annual/archive/03482009.pdf). This average is based on the capacity factors of the existing nuclear reactors, most of which are more than 30 years old. The new generation of nuclear reactors are likely to have somewhat higher capacity factors (see Appendix A, Cases 3 and 4).

In contrast with nuclear power plants, combined-cycle natural gas-fired plants had an average capacity factor of 42.2 percent in 2009, up from 33.5 percent in 2003. As CTCC plants are used more for base-load electricity than simply for peak- or intermediate-load, their average capacity factor has increased. This upward trend can be expected to continue. As a reference point, coal-fired plants typically have capacity factors of 60 to 70 percent (EIA, April 2011).

(7) Fixed and Variable Operation and Maintenance Costs (including fuel costs)

Fixed O&M costs – including, for example, wages, fees, and routine maintenance costs – do not vary directly with power generation. Variable O&M costs – including, for example, costs associated with utilities and fuel – tend to vary as a function of the power output. Fuel costs are sometimes categorized separately but are treated here as a variable O&M cost for purposes of discussion.

Setting aside the possibility of a major plant repair, fuel costs are the big driver of variable O&M costs. The fuel costs for nuclear power plants are low and have long-term predictability. Although the price of uranium has fluctuated, long-term uranium contracts that use a combination of specified pricing and market-related pricing have helped to protect the buyer from market spikes and the seller from market drops (a practice that may be especially viable when, as with uranium, there are relatively few buyers and sellers).

The fuel costs for gas-fired plants are currently very low. Natural gas prices have dropped precipitously in the last few years with the influx of domestically-produced shale gas, making natural gas an attractive option for power generation and other uses. Abundant supply may temper price volatility, but the possibility of price spikes remains. The market-driven short-term contracts typical for natural gas will reflect this volatility. It is also possible that over time, natural gas prices may be driven up by increased domestic or foreign demand.

Price volatility or a steep upward trend in natural gas prices over time would be a serious drawback for gas-fired plants. About 55 percent of a CTCC plant's electricity production costs are fuel costs; one implication is that even a small upward or downward shift in natural gas prices could, over the next 25 years, significantly affect the proportional shares of natural gas and nuclear power in power generation (James, symposium presentation).

On a positive side, new gas-fired combined-cycle plants can now exceed 60-percent efficiency (Steele, symposium presentation), up from an average 45-percent efficiency for 2010 (EIA, November 2011, *Electric Power Annual 2010* http://www.eia.gov/electricity/annual/archive/03482010.pdf). In other words, the amount of energy they must use to generate one kilowatt-hour (kWh) of electricity has dropped. In contrast, coal-fired plants had an average 34-percent efficiency in 2010; nuclear power plants, an average 33-percent efficiency (EIA, November 2011).

(8) Operational Flexibility

Electric utilities increasingly need operational flexibility to take advantage of intermittent electricity sources in their system fleet, especially wind and solar. They also need operational flexibility to respond to different, sometimes unpredictable levels and timing of demand. In the past, utilities used separate plants for base-load and peak-load demand, and this practice continues to some extent. However, a plant with internal operational flexibility is an asset. Full operational flexibility includes load-following (rapidly ramping up or down with changing demand, ideally with a low minimum load required), peaking (providing full output when needed), and two-shifting (shutting down when demand is low and restarting when demand increases).

Large nuclear power reactors – especially today's designs – have some technical capability for operational flexibility, but they typically are operated for base-load power generation only. SMRs prospectively offer more flexibility. The full extent remains to be seen. The mPower SMR , for example, is designed to load-follow much better than a large light water reactor (see Appendix A, Case C). In addition, a site with a suite of SMRs will have incremental flexibility while a site with one large reactor will not: if one SMR is in an outage, the remainder can continue operating.

In contrast with traditional nuclear power plants, which were intended to supply base-load electricity, gas-fired plants have evolved from the other direction. Used in the past mainly for peak demand, gas-fired plants have evolved to advanced CTCC plants that may be used for a range of operational modes, from base- to intermediate- to peak-load.

There are trade-offs with maximizing the operational flexibility of a CTCC plant, however. Cycling (more frequent start-ups) increases emissions and lowers a CTCC plant's capacity factor and efficiency, making it a relatively more costly member of the utility's fleet of EGUs. In addition, with their higher temperatures, improved emissions controls, and more finely-tuned designs, CTCC plants may be less well-suited for cycling than gas-fired plants were in the past: cycling may affect a CTCC plant's performance and reliability.

(9) Climate Change Impacts

There is a widespread scientific consensus that atmospheric emissions of greenhouse gases – especially carbon dioxide (CO_2) and methane (CH_4) – are causing climate change (Solomon et al. (eds.), *Contribution of Working Group I to the Fourth Assessment Report of the intergovernmental Panel on Climate Change, 2007* http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_wg1_report_the_physical_science_basis.htm). Carbon dioxide emissions are far more prevalent, but CH_4 emissions are far more potent. Methane is much shorter-lived in the atmosphere than CO_2 but much more efficient at trapping radiation. Over a 100-year period, the comparative climate change impact of CH_4, ton for ton, is over 20 times greater than CO_2 (EPA, Greenhouse Gas Emissions: Methane Emissions http://epa.gov/climatechange/ghgemissions/gases/ch4.html).

Nuclear power plants have negligible greenhouse gas emissions; this is a major reason for a resurgence of interest in nuclear power. CTCC plants, in contrast, emit CO_2 as well as small amounts of nitrous oxide, but at considerably lower levels than coal-fired plants. CTCC plants have become the benchmark for a Clean Air Act "new source performance standard" that EPA, in response to a 2009 decision of the U.S. Supreme Court, proposed in March 2012 for new fossil fuel-fired EGUs. EPA proposed an output-based standard of 1,000 pounds of CO_2 per megawatt-hour, which, EPA noted, new natural gas combined-cycle EGUs should be able to meet without add-on controls. At this point, EPA is not proposing standards for other greenhouse gases emitted by EGUs, including CH_4 and nitrous oxide, because more information is needed on their quantity and significance (EPA, March 27, 2012, Proposed Rule, Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units http://epa.gov/carbonpollutionstandard/pdfs/20120327proposal.pdf).

While CTCC plants probably will have no difficulty meeting the CO_2 emissions standard proposed in 2012, if in the future a federal policy is adopted to aggressively curb greenhouse gases, emissions from CTCC plants are likely to be too high (James, symposium presentation). This could prompt adding carbon capture and storage (CCS) to CTCC plants, a technology application that is relatively untested at present (Steele, symposium presentation). It also could prompt a shift away from CTCC plants and toward nuclear power (James, symposium presentation).

Methane is the primary component of natural gas, and fugitive natural gas emissions or the incomplete combustion of natural gas releases CH_4 into the atmosphere. Given today's CTCC technology, incomplete combustion by the EGU typically is not a problem. Of greater concern are possible releases of CH_4 "upstream," during the production and distribution of natural gas. The extent of natural gas releases, including venting and leaks at wells and leaks along pipelines, is not well-known at present. Estimates of fugitive natural gas emissions range from 1 to 7 percent. EPA estimates the rate to be about 2.5 percent, but better industry data are needed (Nelson, symposium presentation). The issue is crucial. The recent drop in estimated U.S. greenhouse gas emissions due to the transition from coal to gas could be offset if the fugitive natural gas emissions rate actually is 4 percent or higher; conversely, lowering this rate to 1 percent would produce as much climate benefit as closing one-third of the nation's coal plants (Nelson, symposium presentation).

(10) Other Adverse Environmental Impacts (near term)

There are 104 commercial nuclear power reactors currently operating in the United States. Their near-term adverse environmental impacts, while non-trivial, are well-understood. The same can be said for uranium mining and milling operations: there are few globally, and their near-term environmental effects are fairly well-recognized. CTCC plants have few adverse environmental impacts, but they rely on the abundant supply of natural gas made possible through shale gas production, a burgeoning enterprise being undertaken by a large number of companies. Water is a key environmental issue with both nuclear power plants and shale gas production. The similarities stop there.

A major concern with nuclear power plants is their potential effect on aquatic life. A nuclear power plant requires water to remove waste heat from the reactor. (For an exception, see the reference to an air-cooled SMR in Appendix A, Case 3.) In doing so, the plant uses large quantities of water. While most of it eventually is returned to its river, lake, or ocean source, some is consumed as water vapor and the rest may be as much as 30 degrees F. hotter upon its discharge from the plant. These problems are tempered somewhat when a closed-loop rather than a once-through cooling system is used, but they remain a concern. The state, not the federal government, regulates a nuclear power plant's water usage, including quantity limits on water withdrawals as well as thermal limits on released water. In times of drought and hot weather, a nuclear power plant may have to reduce or suspend operations to avoid adding hot water to an already-stressed aquatic system (Lochbaum, symposium presentation; Union of Concerned Scientists, October 2007, Issue Brief, "Got Water?" http://www.ucsusa.org/assets/documents/nuclear_power/20071204-ucs-brief-got-water.pdf).

Nuclear power plants have negligible emissions of conventional air and water pollutants, but they do have the potential for air- and water-borne releases of small quantities of radioactive material during normal operation. These releases are monitored and regulated by NRC (NRC, Fact Sheet on Radiation Monitoring at Nuclear Power Plants and the "Tooth Fairy" Issue http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/rad-monitoring-and-tooth-fairy.html).

CTCC plants have few immediate environmental impacts: in contrast with coal-fired plants, their emissions of criteria and hazardous air pollutants are low, and their potential impacts on local water systems are minor. The same cannot be said about natural gas production, however, especially shale gas production.

Natural gas wells may release significant levels of nitrogen oxides and volatile organic compounds (Nelson, symposium presentation). In addition, the spread of hydraulic fracturing ("fracking") processes to recover gas trapped in shale formations has raised major concerns about water contamination and consumption. There have been no confirmed cases of drinking water contamination due to pathways created by fracking, but contamination because of casing failures, blowouts, spills, etc. are possible (Nelson, symposium presentation). These problems are not unique to fracking, but the extraordinary water demands of the fracking process are.

A fracking process requires large quantities of water; the amount used by a well over time depends on whether the water is used once or is reused. The effects of a water withdrawal for fracking on natural hydrologic cycles will depend partly on how and where it is released: for example, in Texas it is mostly removed from the hydrologic cycle through injection; in Pennsylvania, it is mostly returned to the hydrologic cycle through treatment and disposal (Nelson, symposium presentation). The regulation of fracking is at present a patchwork of state regulations. The U.S. Environmental Protection Agency currently is studying the effects of fracking on drinking water and in April 2012 signed a memorandum of agreement with the U.S. Departments of Interior and Energy to address the challenges associated with developing shale gas (EPA, Natural Gas Extraction – Hydraulic Fracturing http://www2.epa.gov/hydraulicfracturing) , but so far the federal government has not taken a definitive position on fracking.

One challenge is the fracking process itself: fracking technologies are evolving rapidly. Another challenge is the number of companies involved. Thousands of companies – companies with different capacities and practices – are actively drilling in the United States; the top 40 companies have only about 45 percent of the market share (Nelson, symposium presentation). All will require regulation and oversight. In addition, regulatory attention will be needed regarding the hundreds of truck trips associated with a single fracking well to build the well and pipeline, deliver water and haul it away, etc. Some best practices for fracking have been identified: for example, the full disclosure of fracking chemicals, modernization of well construction and operation, and improved air quality and water management regulations (Nelson, symposium presentation). Their implementation remains a challenge.

(11) Other Adverse Environmental Impacts (distant future)

Like anthropogenic greenhouse gases, the nuclear wastes produced today cast a shadow over the distant future. The adverse effects of a greenhouse gas build-up already are being felt. In contrast, the adverse effects of nuclear waste are not likely to be felt in our lifetimes, but many argue that our responsibilities to future generations include secure disposal of our nuclear wastes.

High-level radioactive waste (HLW), including spent fuel, has relatively intense concentrations of highly radioactive and extremely long-lived radionuclides. Decay to background levels can take hundreds of thousands of years (NRC, High-Level Waste http://www.nrc.gov/waste/high-level-waste.html). In the interim, HLW must be isolated to prevent harmful exposure. While dry cask storage at nuclear power plants may adequately protect human health and the environment for a hundred years or more, it is not a viable permanent solution. As mentioned above (see "Safety Imperatives"), the federal government as yet has no arrangement for long-term management of HLW.

Despite the 1982 Nuclear Waste Policy Act, which was enacted to deal with the nation's HLW problem; despite an ongoing revenue stream from nuclear utilities and their ratepayers, which was required under the act in exchange for the federal government's taking ultimate responsibility for HLW; despite the 1987 amendments to the act, which designated Yucca Mountain in Nevada as the preferred site for a HLW geologic repository; and despite more than a decade spent on the proposed Yucca Mountain site – despite all this, an impasse had been reached by 2010. The Blue Ribbon Commission on America's Nuclear Future, established as an ad hoc commission in accordance with a January 2010 presidential memorandum to DOE, was an attempt to resolve the impasse. In its final January 2012 report to the DOE Secretary, the commission called for, among other things, prompt efforts to develop one or more geologic disposal facilities as well as one or more consolidated interim storage facilities; a consent-based approach to siting these facilities; a new, federally-chartered corporation dedicated solely to implementing the nuclear waste management program; and full access to the funds provided for the purpose of nuclear waste management by nuclear utility ratepayers (Blue Ribbon Commission on America's Nuclear Future, January 2012, *Report to the Secretary of Energy* http://cybercemetery.unt.edu/archive/brc/20120620220235/http://brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf). Implementing these recommendations will require legislative action.

In the meantime, NRC's rule regarding HLW storage and disposal – that is, its Waste Confidence Decision and Rule (10 CFR 51.23) adopted in 1984 and updated in 1990 and 2010 – was vacated in June 2012 by the U.S. Court of Appeals for the D.C. Circuit, which found that NRC had not fulfilled its NEPA obligations. The NRC has suspended issuing licenses that rely on the rule until a final EIS and rule are issued in 2014 (NRC, Waste Confidence http://www.nrc.gov/waste/spent-fuel-storage/wcd.html). In the interim, licensing reviews and proceedings will continue to move forward (Rothwell, symposium presentation).

(12) Security Risks

While malicious disruption of electricity generation could occur at gas-fired plants or along their gas supply pipelines, nuclear power plants generally are thought to be more likely targets of threats to national security. The question then is "how likely, and with what effects?"

Threats to national security could occur from sabotage or theft coming from either inside (e.g., disgruntled or compromised staff) or outside (e.g., intruders or others with unauthorized access), but nuclear power plants in the United States seem to have fairly robust security systems (Hall, symposium presentation). The NRC conducts a baseline security inspection program for nuclear power plants. Of its total findings of security deficiencies for 2011, 92 percent were of very low security significance and only 1.4 percent were of high security significance (NRC, September 2012, *Report to Congress on the Security Inspection Program for Commercial Power Reactors and Category I Fuel Cycle Facilities: Results and Status Update* http://pbadupws.nrc.gov/docs/ML1225/ML12251A017.pdf).

A nuclear power plant is not a nuclear weapon – it can't suffer a nuclear explosion – and its nuclear and radiological materials are not easily accessed or dispersed. Nevertheless, the loss of power generation capacity at a nuclear power plant could have significant local and regional economic impacts, and the environmental impacts of a prolonged loss of nuclear power could be globally significant (Hall, symposium presentation). In the United States, at-plant storage of spent fuel – especially at closed plants – is suboptimal from a security standpoint. However, the greatest threats from nuclear power arise on the international front with the proliferation of nuclear power, nuclear materials, and nuclear weapons (Hall, symposium presentation).

III. Public Policy Implications: Cross-Cutting Themes

What kinds of public policies are needed? While not the main topic of the symposium, this question did arise.

Two broad questions cropped up often: (1) should the government avoid "picking winners and losers"? and (2) should the government undertake long-range planning for electricity generation and transmission? These questions cannot be answered conclusively: ultimately, their answers depend on individual, deeply-held beliefs and values.

In addition, however, five more targeted suggestions emerged:

- **Develop regulations that are based on forward-thinking analysis, take into account multiple pollutants in multiple media, allow adequate lead times for utilities to prepare for regulatory changes, and reduce uncertainty while increasing flexibility.**
- **Recognize that capital cost accounting practices affect electricity generation choices.**
- **Think proactively about the effects of severe and persistent droughts on water supplies for fuel production and electricity generation.**
- **Take into account the power generation implications of improvements to electricity transmission and distribution systems.**
- **Optimize the possibilities of demand-response programs.**

Consensus on these suggestions was not sought, but they may be useful for public policymakers as well as the electric utility industry.

The symposium discourse was mainly descriptive and analytic, but speakers and other participants also made comments about where public policies *should* head. Seven normative themes that came up especially often, cutting across the symposium's three sessions, are synopsized below.

Two broad themes are captioned as questions because, while arguments can be made in response, their answers ultimately depend on deeply-held beliefs and values:

- **Would it be desirable for the government to avoid "picking winners and losers"?**

  Several symposium participants commented that the government should avoid "picking winners and losers" among electricity generation technologies: instead, the market should sort out which technologies prevail. Would this be desirable?

  The full spectrum of public policies – from "carrots" (e.g., grants, tax credits, loan guarantees) to "sticks" (e.g., regulations, taxes, fees) – can affect the comparative prospects of an electricity generation technology. On the one hand, it can be argued that federal and state governments should not offer carrots; that their appropriate role is to ensure a level playing field and the internalization of externalities. On the other hand, it can be argued that avoiding carrots is difficult and may not be desirable in all cases. Even well-established technologies often benefit from favorable public policies, such as arrangements that allow leasing public land for fuel extraction.

In addition, some nascent technologies might not be able to demonstrate their potential without a boost from government; moreover, they may face barriers attributable to government. The SMR is a case in point. In the United States all nuclear power expansion, small and large, is inhibited by the federal government's failure to realize the goals of the 1982 Nuclear Waste Policy Act and by the federal government's lack, thus far, of an aggressive policy on greenhouse gas emissions; in addition, several state governments have moratoria on or other barriers to new nuclear power plants (Ingersoll, symposium presentation; Rothwell, symposium presentation). Despite these impediments, SMRs show some promise. Their development in the United States has been enabled by federal government support, most recently prompted by House and Senate bills in 2009 and 2010 (Ingersoll, symposium presentation).

An alternative to avoiding picking winners and losers would be to acknowledge that public policies do pick winners and then to assess prospective winners in light of key national goals such as climate change mitigation and national security. This would require agreement on those key goals.

- **Would it be desirable to have comprehensive long-range government planning for electricity generation and transmission?**

  Some symposium participants commented that in the United States, public policies regarding electricity generation and transmission are fragmented and that focused long-range planning by federal and state governments is needed.

  While many state governments have energy plans, most do not engage in comprehensive long-range planning for electricity. The federal government's long-range energy plans, such as they are, may be revised by new administrations. Under our current system, long-range government planning regarding electricity may not be feasible. Even if it were, would it be efficacious?

  Although investments in electricity generation, transmission, and distribution are long-lived, the external context within which electric utilities operate can – as pointed out in Section I – alter rapidly. Long-range planning accordingly would need to be flexible and responsive to new conditions and opportunities, but that flexibility and responsiveness would dilute the predictability of public policies formulated around long-range plans.

The remaining five cross-cutting themes are more targeted. They are posed below as advice to policymakers within government and, by implication, within the electric utility industry.

- **Develop regulations that are based on forward-thinking analysis, take into account multiple pollutants in multiple media, allow adequate lead times for utilities to prepare for regulatory changes, and reduce uncertainty while increasing flexibility.**

  Regulations should not be based solely on an analysis of historical data; analysis of probable future trends should be incorporated. In addition, myopic rules that focus on single pollutants in a single medium (e.g., air) may simply shift the problem to another medium and may contribute to inefficient compliance measures. Moreover, for utilities to prepare properly and economically for regulatory changes, they need adequate lead times and – when a regulatory agency issues several key rules concurrently – staggered compliance dates. Finally, as discussed in Section I, utilities must cope with numerous uncertainties. Some uncertainties are unavoidable but, when appropriate, regulatory certainty and flexibility should be maximized.

- **Recognize that capital cost accounting practices affect electricity generation choices.**

  Choices about investments in a new EGU are affected by the capital cost accounting practices used. This is especially true for nuclear power plants, with their high capital costs and long construction times. In states that have continued to regulate investor-owned electric utilities, there are two alternative regulatory methods for calculating interest during construction: "allowance for funds used during construction" (AFUDC) accounting and "construction work in progress" (CWIP) accounting. The CWIP method allows the utility to charge current customers for costs associated with the new EGU under construction; the AFUDC method does not. The AFUDC method thus discourages investments in EGUs such as nuclear power plants, as do the competitive electricity markets in deregulated states, where there is no guarantee that construction costs can be recovered at rates that can compete with those of less capital-intensive EGUs (Rothwell, symposium presentation). The consequences – intended or unintended – of accounting methods in regulated states and of competition in deregulated states should be taken into account by state policymakers.

- **Think proactively about the effects of severe and persistent droughts on water supplies for fuel production and electricity generation.**

  With climate change, severe and persistent droughts are more likely. Federal and state policymakers need to anticipate prolonged water shortages and consider their implications for both water-intensive fuel production (e.g., hydraulic fracturing) and water-intensive electricity generation (e.g., nuclear power reactors), taking into account other human and environmental needs for water.

- **Take into account the power generation implications of improvements to electricity transmission and distribution systems.**

  The shortcomings of the existing systems of electricity transmission and distribution in the United States are fairly well-understood. Addressing them through means such as supergrids will offer the potential for saving on investments in new power generation, as will smart grids that enable taking advantage of distributed electricity generation.

- **Optimize the possibilities of demand-response programs.**

  Demand-response programs – typically, through electricity pricing that encourages customers to reduce demand (e.g., adjust thermostats) or to shift demand (e.g., run appliances during off-peak hours) – can save customers money, make more efficient use of EGUs, and improve system reliability. Large industrial customers are much better acquainted than residential customers with these savings possibilities and have more structured arrangements with their utilities. Appropriate price signals and widespread consumer knowledge are needed for demand-response programs to work optimally.

Consensus on these suggestions was not sought. Nevertheless, they may prove useful to policymakers within federal and state government as well as the electric utility industry, as they undertake the difficult task of ensuring that the nation’s systems of electricity generation, transmission, and distribution are sustainable, reliable, and affordable.

Background Reading

These publications are not cited in the text but may be useful to readers seeking background information on electricity generation, transmission, and distribution.

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APPENDIX A:

FOUR CASE EXAMPLES

The following case examples are based mainly on presentations in the "Illustrative Examples" part of each symposium session. These include the presentations of Jeffrey Burleson (Southern Company), Andrew Kosnaski (TVA), Kevin Murray (Duke Energy), Jeffrey Perry (TVA), David Sorrick (Duke Energy), Daniel Stout (TVA), and Roger Waldrep (TVA). To view their presentation slides, see http://bakercenter.utk.edu/symposium-agenda/ .

CASE 1.

The John Sevier combustion-turbine combined-cycle plant of the Tennessee Valley Authority

The John Sevier combustion-turbine combined-cycle (CTCC) plant is in northeastern Tennessee, on the site of the John Sevier Fossil Plant of the Tennessee Valley Authority (TVA). At this site, two of the plant's four coal-fired units are being retired under an April 2011 settlement with the U.S. Environmental Protection Agency and the remaining two are being idled.

A lawsuit filed by the State of North Carolina in 2006 claimed emissions from TVA's John Sevier Fossil Plant and other coal-fired plants were contributing to the state's air quality problems and sought specific remedies. In January 2009, the court granted North Carolina's requests in part and ordered TVA to accelerate its plans to install advanced pollution control equipment. TVA could not meet the court's December 31, 2011 deadline without idling the plant. TVA responded by building CTCC capacity, giving it the flexibility to either idle the coal units and install controls or retire those units. In accordance with the National Environmental Policy Act, as a federal corporation TVA was required to perform an environmental assessment before construction of the CTCC plant started. Construction began in 2010 and was completed in the spring of 2012. The project cost approximately $800 million and has an 880-MW capacity.

Several factors drove the decision to convert to gas-fired units at John Sevier:

Cleaner energy. When compared with a conventional coal-fired plant on a lbs/MWh basis, the John Sevier CTCC plant emits about 1 percent as much sulfur oxide, about 20 percent as much nitrogen oxide, and about 50 percent as much CO_2.

Lower total expected cost. TVA's analysis indicated that building the CTCC plant had an approximate present value of $100 million in lower expected cost than retrofitting the coal plant with pollution controls; moreover, the economic case becomes even stronger if one believes that CO_2e emissions eventually will come with a cost.

Lower and less volatile natural gas prices than in the past. TVA's analysis indicated a much tighter price distribution and lower risk of price blowouts than natural gas previously had. Shale gas has, according to TVA's analysis, changed the game in terms of pricing and volatility and has sharply reduced coal's traditional pricing advantage.

Portfolio balance and diversity. According to TVA's 2010 Integrated Resource Plan, in 2008 approximately 55 percent of TVA's electricity was produced from coal and natural gas-fired plants (54% coal and 1% gas); 30 percent, from nuclear power plants; and 5 percent, from hydroelectric plants (less than in recent years because of a severe drought). Most of the remaining 10 percent was purchased power; a small proportion was from renewables (wind, solar, biomass). TVA wants a more balanced portfolio and sees natural gas as a promising fuel source, under-represented in this portfolio.

The CTCC project includes three combustion turbines built by General Electric and a steam turbine-generator built by Toshiba. Exhaust from the combustion turbine can be directed through a bypass stack for simple-cycle operation, or the exhaust can be directed to the heat recovery steam generator (HRSG) to produce steam to be sent to the steam turbine-generator for combined-cycle operation. In its simple-cycle mode, the plant produces 490 MW; in its combined-cycle mode, 880 MW. Power can be ramped up or down: in a 3X1 configuration (three combustion turbines and one steam turbine), the automatic generation control (AGC) range is approximately 400 MW, with a 50 MW/minute rate of change; in a 1x1 configuration, the plant can operate as low as 160 MW.

The plant has dual fuel capability: it can operate on either natural gas or, as a back-up, No. 2 fuel oil. It can connect electrically to either the local 161 kV switch yard or a 500 kV interconnect 13 miles away. For additional reliability and/or flexibility, the CTCC plant has a number of other features, such as auxiliary transformers, load commutated inverters (LCIs) for starting the combustion turbines, and one cooling water module per combustion turbine.

Environmental attributes of the plant that favored the CTCC approach included (1) greater energy efficiency than a conventional coal-fired plant (50-55 percent efficiency in its combined-cycle mode, contrasted with the 30-35 percent efficiency typical of a coal-fired unit), and (2) no ash, with only a minimal amount of other solid waste. Other environmental design features of the CTCC plant included, for example, air pollution controls in the HRSG design and acidity, chlorine, and temperature control strategies in the discharge pond design to protect the receiving stream.

Gas is supplied to the John Sevier plant by Spectra Energy. In March 2010, Spectra Energy signed a "precedent agreement" with TVA to provide firm transportation services of up to 150 million cubic feet per day of natural gas to the plant. The project, at an estimated capital cost of $135 million, included expanding or modifying existing parts of Spectra Energy's East Tennessee Natural Gas system and building a new 8.5-mile lateral to the plant. The lateral generally followed TVA's existing transmission line right-of-way, partially to minimize impacts on landowners and the environment.

Financing the plant was a challenge, especially given TVA's congressionally-mandated $30 billion debt ceiling. In January 2012, TVA announced that it would lease the use of the CTCC plant to John Sevier Combined Cycle Generation LLC for 30 years in return for $1 billion.

CASE 2.

The Sutton combustion-turbine combined-cycle plant of Progress Energy (now Duke Energy)

Progress Energy was a large investor-owned utility formed in 2000 through a merger of Carolina Power & Light and Florida Progress Corporation. One of its operations was the Sutton Energy Complex near Wilmington in far-eastern North Carolina. Progress Energy merged with Duke Energy in July 2012.

In 2009, Progress Energy announced plans to retire its three coal-fired units totaling 575 MW at the Sutton Energy Complex and construct a 625-MW combustion-turbine combined-cycle (CTCC) plant there. In June 2010, the North Carolina Utilities Commission (NCUC) gave permission to build the plant. The project broke ground in May 2011 and is expected to be completed by 2014. Its estimated cost is about $600 million.

The Sutton project has a 2x1 configuration, with the Siemens F-Class gas turbines capable of burning either natural gas or ultra-low-sulfur distillate oil. The plant will be able to operate in either a simple-cycle or a combined-cycle mode. Total output will be about 550 MW, with additional duct firing capacity for an added 70 MW during summer peak periods.

A similar project of Progress Energy – now Duke Energy – is going on near Goldsboro, in eastern North Carolina. Three coal-fired units totaling 382 MW at the 61-year-old H.F. Lee Plant were retired in 2012. Adjacent to the site, on the existing Wayne County Energy Complex, which has five dual-fueled combustion turbines, the company is building a new 950-megawatt natural gas-fired plant. The new plant will cost an estimated $900 million and is planned to come on line in 2013. Piedmont Natural Gas – a natural gas provider operating in parts of North Carolina, South Carolina, and Tennessee – has built a 38-mile pipeline to the Wayne County Energy Complex and is building a 128-mile pipeline to the Sutton plant.

Before the decision by Progress Energy to request a Certificate of Convenience and Public Necessity from NCUC for the Sutton CTCC plant, other options were considered. One major alternative was to modify the existing coal-fired units as necessary to meet new regulations. Key factors that tipped the balance in favor of the Sutton CTCC plant are summarized below.

> **Increasing the system's fuel diversity.** Prior to the recent suite of plant conversions, 70 percent of the generation capacity of Progress Energy in North Carolina and South Carolina was based on coal, with less than 10 percent based on natural gas. It was seen as desirable to rebalance the fuel mix, reducing reliance on one fuel type in order to dampen the effects of, for example, fuel price swings, fuel supply disruptions, and new regulations that affect one fuel type more than others.
>
> **Complying with new environmental regulations affecting EGUs that burn fossil fuels.** Key recent federal air pollution regulations include the Clean Air Interstate Rule and its later incarnation, the Cross-State Air Pollution Rule, as well as the Mercury and Air Toxics Standards for power plants. In addition, under North Carolina's 2002 Clean Smokestacks Act, coal-fired power plants in North Carolina were required to cut their smog- and haze-forming emissions by about 75 percent over the coming decade. Regulations regarding the disposal of coal

combustion residuals and the treatment of waste water also were factors. These regulations, together with others that might be in the offing, were considered when comparing options. The comparison took into account the coal-fired units' age (about 40 years), size, and condition, as well as the cost of retrofitting them with the advanced air pollution controls. Replacing the existing units was found to be economically more attractive than retrofitting them.

Curbing long-term maintenance costs. In addition to the costs of environmental compliance, the cost of future plant maintenance was considered. Despite their relatively small MW output, the coal-fired units could require significant investments to keep them viable.

Realizing fuel cost savings. According to the company's analysis, with current natural gas prices the generation costs of a new CCTC unit would be significantly less than those of a coal-fired unit.

Factoring in fuel price volatility. Analysis indicated that although coal prices historically were very stable, they had become more volatile in recent years. In contrast, the volatility of natural gas prices has moderated somewhat with new supply options.

Technological risk was recognized as a possible downside of the decision to retire the coal-fired units and build the new CTCC plant. Advanced-technology combustion turbines are "unforgiving": They operate at temperatures hot enough to melt conventional metals. Without proper precautions, this could lead to component failures and expensive repairs. To reduce this risk, an advanced but proven combustion turbine was chosen over newer turbines.

The CTCC plant could have been built at a greenfield site, but it was determined that the existing Sutton Energy Complex offered several advantages. First, basic infrastructure components (transmission lines, water, cooling ponds) were already there. Second, the Sutton Energy Project is only 90 miles from the Wayne County Energy Complex, where new gas-fired units had been started one year earlier. This enabled leveraging the supply chain by using similar vendors for the two projects, which resulted in cost savings on the Sutton project. And third, because the existing site is at the far eastern end of Duke Energy's system, it was important that generation be replaced in the same area.

CASE 3.

The possible small modular reactor project of the Tennessee Valley Authority at its Clinch River site

In a November 2010 letter to the U.S. Nuclear Regulatory Commission (NRC), the Tennessee Valley Authority (TVA) outlined assumptions for the possible permitting and licensing of mPower small modular reactors (SMRs) to be located on its Clinch River site in Oak Ridge, Tennessee. In January 2011, NRC responded that there were no legal or licensing issues that would prevent TVA from applying.

Babcock & Wilcox (B&W) is developing the mPower SMR in tandem with Bechtel through their Generation mPower partnership. A Clinch River Site Project Regulatory Framework is being developed by TVA in consultation with NRC. It is expected that B&W would submit the design certification application to NRC, and TVA would apply for the construction permit and operating license for up to four

SMRs at the Clinch River site. As of late 2012, however, the project remains a possibility, not a certainty. Funding is a key issue.

As yet in the United States, no SMRs have been licensed or constructed, although the SMR concept has attracted attention. One obstacle has been the cost of detailed design and engineering. In March 2012, President Obama announced that a total of $452 million would be made available by the U.S. Department of Energy (DOE) through cost-share grants to support first-of-its-kind engineering, design certification, and licensing for up to two SMR designs over five years, subject to congressional appropriations. TVA is part of the B&W team that in May 2012 submitted an application to DOE for a cost-share grant. Westinghouse Electric, Holtec International, and NuScale Power also submitted bids. On November 27, 2012, DOE announced the selection of the B&W/TVA team as the only team to receive a grant.

The B&W mPower reactor – a scaled-down and simplified version of a pressurized water reactor – is rated at 180 MW of capacity. The current plan is to license up to four units at the Clinch River site. As of September 2012, TVA was committed to exploring the development of this technology and had set preliminary milestones of 2014 to submit a license application, 2017 to receive the NRC license, and 2022 to begin commercial operation. Water-cooled or air-cooled condenser options are being explored: With the water-cooled approach, the facility site would be 38 acres. Site evaluation activities are underway, and site layout and infrastructure plans are being developed.

TVA's commitment to the SMR concept is based on their assessment of several factors:

> **Positive implications for the operating fleet.** The SMR approach would increase TVA's ability to replace aging coal-fired plants, thereby reducing CO_2 emissions, and it would provide added stability and flexibility to TVA's base-load operations. (The mPower SMR is designed to improve power generation flexibility: it has a control rod in each fuel assembly and no boron chemistry control, enabling much better load-following capability than that of large light water reactors.) In addition, SMRs could be deployed in smaller increments than large reactors; this "scale-up" option would help to minimize the financial risks of new nuclear power units. The small size of the SMRs and their site footprints offers more siting options, including locating electricity generation closer to loads. The air-cooled rather than water-cooled condenser option opens up the possibility of sites without access to water for cooling.
>
> **Shorter construction times than large reactors, resulting in lower capital costs.** Large nuclear reactors are expensive: A new one can cost well over $5 billion. SMRs are expensive also, but their construction times are expected to be significantly shorter. (The construction time for an mPower SMR with a water-cooled condenser is estimated to be about three years.) According to TVA's analysis, if an 8 percent financing rate is assumed, the shorter construction time of the SMR could cut the financing component of the total capital cost by more than half.
>
> **Benefits of simplified, modular, repeatable design.** B&W's goal is to have at least 70 percent of the SMR construction be modular, rail-shippable, and repeatable. The expectation is that this will lead to construction cost savings and to robust quality assurance at the fabrication plants.
>
> **Enhanced safety.** The SMR will have a simple, "passive safety" design. For example, during "design basis" accidents, the core remains covered, no power is needed for emergency core cooling, and there are no shared active safety systems between units.

Enhanced security. Located fully underground, the plant could be more easily protected from external threats than a conventional large nuclear plant could.

As with a large nuclear power reactor, an SMR is expected to compete well economically against other generation sources once it is up and running: It is expected to have a very high capacity factor, low and predictable fuel costs, and negligible life-cycle CO_2 emissions. The major challenge with deploying an SMR is its initial capital cost. As of late 2012, TVA analysis indicates that the cost challenges of the SMR are serious and the business case remains to be made, especially given the “first-of-a-kind” risks of this project. The plan apparently is to proceed cautiously, with “decision gates” before submitting a license application and again before beginning construction.

CASE 4.

The Westinghouse AP1000 project of Southern Nuclear at Plant Vogtle Units 3 and 4

Plant Vogtle is located on a 3,100-acre site in eastern Georgia, on the Savannah River across from South Carolina and the Savannah River Site of the U.S. Department of Energy. The plant is owned by Georgia Power – a subsidiary of Southern Company – and three co-owners; together they provide most of Georgia’s electric service. Georgia Power, the only investor-owned utility in the state, holds a 45.7 percent share of Plant Vogtle and is its largest owner. The plant is operated by Southern Nuclear, also a subsidiary of Southern Company.

Units 1 and 2 of Plant Vogtle came on line in the late 1980s. Each uses a Westinghouse pressurized water reactor design and has about 1,200 MW of capacity. Units 3 and 4 of Plant Vogtle are the first nuclear power reactors to be licensed in the United States since the 1970s. Each will provide an additional 1,100 MW of capacity, with an anticipated 93 percent capacity factor. According to Southern Company, electricity demand in the Southeast is projected to increase 27 percent by 2030.

In 2004, Southern Company became a founding member of the NuStart Energy Consortium, organized to (1) demonstrate NRC’s process for obtaining a combined Construction and Operating License (COL) for an advanced nuclear power plant, and (2) complete the design engineering for two advanced reactor technologies. Westinghouse Electric’s Advanced Passive 1000 (AP1000) technology was one of the two selected. In 2009, the operating license of Plant Vogtle Units 1 and 2 were extended for 20 years, its Units 3 and 4 were named the NuStart reference plant for the AP1000 technology, and these units received an Early Site Permit and Limited Work Authorizations from NRC. In February 2010, the units were awarded a conditional commitment of $8.33 billion in federal loan guarantees by the U.S. Department of Energy (DOE). In August 2011, NRC issued its Final Safety Evaluation Report for the COLs for Plant Vogtle’s new units, and in December 2011, it certified the Westinghouse AP1000 design. In February 2012, the five commissioners of the NRC approved the COLs by a vote of 4 to 1.

Simultaneously, Georgia Power had to follow state processes for new generation. The Georgia Public Service Commission (GPSC) mainly regulates investor-owned utilities and has only limited jurisdiction over electric membership corporations and municipally-owned utilities. As the only investor-owned utility in the state, Georgia Power was required by 1991 state legislation to obtain GPSC certification prior to new plant construction and also to prepare integrated resource plans (IRPs) that analyze supply and demand, look forward 20 years, are updated every three years, and are subject to GPSC approval. In 2009, GPSC certified Units 3 and 4 of Plant Vogtle. In 2010, it approved Georgia Power's 2010 IRP with modifications.

Unit 3 is expected to begin commercial operation in 2016; Unit 4 in 2017. Based on this schedule, the reactors will take about 11 years from conception to commercial operation. The total cost of building the two reactors, including financing costs, is expected to be about $13 billion. Georgia Power's portion of these costs will be about $6.1 billion, of which about $1.7 billion (28 %) will be financing costs. In 2009, state legislation – the Georgia Nuclear Energy Financing Act – expedited the recovery of utility-incurred financing costs associated with new nuclear power construction by providing for their recovery during the construction period, using an accounting method authorized by GPSC. In the long run, according to Southern Company, this will save Georgia Power customers $300 million.

Several factors influenced the decision by Southern Company and its subsidiaries to undertake this project:

Mix of new electricity generation sources. Southern Company currently has about 43,500 MW of generating capacity and in 2011 generated 52 percent of its electricity from coal, 30 percent from gas, 16 percent from nuclear, and 2 percent from hydro. Resource additions currently planned for 2011-2017 emphasize gas (about 4,300 MW total, installed and purchased) and nuclear (about 1,000 MW owned by Georgia Power), with an estimated additional 1,500 MW in total from energy efficiency improvements, a first of a kind "clean coal" project (coal gasification with CO_2 capture), wind power purchases, and solar photovoltaic projects.

Comparative advantages of nuclear energy. In addition to the low-carbon footprint of nuclear power, Southern Company estimates that its 2011 cost of fuel in cents per kWh was 0.72, compared with 3.89 for natural gas and 4.02 for coal. Using the most likely range of natural gas and carbon price scenarios, Plant Vogtle Units 3 and 4 were estimated by GPSC staff consultants to have a $2.2 billion present value life-cycle cost benefit when compared with a generation expansion plan that used natural gas-fired capacity instead of Units 3 and 4.

Additional economic benefits for customers. Georgia Power customers could see potential benefits up to $2 billion in the form of savings from recovering financing costs during construction; production tax credits provided for in the 2005 federal Energy Policy Act; lower-than-forecast interest rates, including potential U.S. Department of Energy loan guarantees; and lower-than-forecast commodity costs.

Recent improvements in the design, licensing, and construction process for nuclear power. According to Southern Company, compared with prior nuclear power reactors the AP1000 design is simplified, with 85 percent less cable, 80 percent less pipe, 50 percent fewer valves, 45 percent less seismic building, and 35 percent fewer safety grade pumps. Licensing approval by NRC prior to safety-related construction is streamlined, and, together with standardized design, improved construction techniques – including modular construction – speed construction and lower costs.

Passive safety systems. The AP1000 design includes such passive safety features as not requiring operator actions for 72 hours to maintain core and containment cooling and not requiring AC power or pumps to achieve a safe shutdown.

The Plant Vogtle project has been the subject of several lawsuits concerning, e.g., construction costs and safety. NRC issued a final Environmental Impact Statement (EIS) in August 2008 for an Early Site Permit and in March 2011 issued a final Supplemental EIS for the two units' COLs. A central issue of one of the lawsuits is whether, in light of the potential safety problems with nuclear power plants highlighted by the March 2011 tsunami-triggered disaster at the Fukushima Daiichi plant in Japan, a new EIS should be prepared for Plant Vogtle's Units 3 and 4, explaining how the reactors' cooling systems and spent fuel pools will be engineered to protect against earthquakes, flooding, and prolonged loss of electrical power. According to Southern Company, NRC's Fukushima 90-day Task Force noted that the AP1000 design already met most of its recommendations. As of late 2012, the lawsuits remained pending but construction on Units 3 and 4 was proceeding.

APPENDIX B:

<u>SYMPOSIUM PROGRAM</u>

Base-load Electricity from Natural Gas and Nuclear Power: The Role of Federal and State Policy

Thursday, September 20, 2012

7:30 – 8:15 AM Registration and Continental Breakfast

8:15 – 9:00 Introduction to the Symposium

8:15 – 8:20 **Welcome**
Dr. Matthew Murray, Director, Baker Center
and
Dr. Mary English, Fellow for Energy and Environmental Policy, Baker Center

8:20 – 8:30 **Opening Remarks**
Dr. Joseph Hoagland
Senior Vice President, Policy and Oversight, Tennessee Valley Authority

8:30 – 9:00 **Context for the Symposium**
"The Challenge Ahead: Balancing Base-load and Operational Flexibility"
Mr. Revis James
Director, Generation Research and Development,
Electric Power Research Institute

9:00 – 12:15 Session I. Policy Analysis of Technical Factors

9:00 – 9:10 **Session Purpose**
Session Chair: Dr. J. Wesley Hines
Head, Department of Nuclear Engineering, University of Tennessee

9:10 – 10:00 **Illustrative Examples: Technical Considerations**

- 9:10 – 9:20 ***TVA's Combustion Turbine Combined-Cycle (CTCC) John Sevier Plant***
  Mr. Roger Waldrep
  Project Construction Manager, Tennessee Valley Authority

- 9:20 – 9:30 ***Duke Energy's CTCC Sutton Plant***
  Mr. Kevin Murray
  Director, Enterprise Project Management Center of Excellence,
  Duke Energy, and
  Mr. David Sorrick
  Vice President, Power Generation Operations, Duke Energy

- 9:30 – 9:40 ***TVA's Small Modular Reactor (SMR) Project at the Clinch River Site***
  Mr. Daniel Stout
  Senior Manager, SMR Technology, Tennessee Valley Authority

- 9:40 – 9:50 ***Southern Nuclear's AP1000 Reactors at Plant Vogtle Units 3 & 4***
  Mr. Jeffrey Burleson
  Vice President of System Planning, Southern Company

9:50 – 10:15 **Break**

10:15 – 11:15 **Subject Matter Experts: Perspectives on the Session Topic**

- 10:15 – 10:35 ***"The Future is Bright for Gas Turbine Power Generation"***
  Dr. Robert Steele
  Program Manager, Combined Cycle Turbomachinery (P79),
  Electric Power Research Institute

- 10:35 – 10:55 ***"Policy Implications of Technology Options for Small Modular Reactors"***
  Dr. Daniel Ingersoll
  Director of Research Collaborations, NuScale Power

- 10:55 – 11:15 "***The Nuclear Regulatory Commission's Environmental Review Process for New Reactors"***
  Mr. Jack Cushing
  Senior Project Manager, Office of New Reactors,
  U.S. Nuclear Regulatory Commission

11:15 – 12:15 **Discussion and Q&A: Implications for Future Public Policies**
Panel (all Session I speakers) and participants

12:15 – 1:15 Lunch, with remarks by contributing sponsors

12:45 – 1:00 ***"Natural Gas: Smarter Power Today"***
Ms. Michelle Bloodworth
Vice President, State Affairs and Business Development,
America's Natural Gas Alliance

1:00 – 1:10 ***"Natural Gas Pipeline Infrastructure and Spectra's Role in the Region"***
Mr. David Shammo
Vice President, Business Development, Southeast Operations
Spectra Energy Corporation

1:30 – 4:40 Session II. Policy Analysis of Economic Factors

1:30 – 1:40 **Session Purpose**
Session Chair: Dr. Jacob LaRiviere
Assistant Professor, Department of Economics, University of Tennessee, and
Fellow for Energy and Environmental Policy, Baker Center

1:40 – 2:20 **Illustrative Examples: <u>Economic Considerations for the Utility and the Region</u>**

- 1:40 – 2:00 ***TVA's CTCC John Sevier Plant and SMR Project at the Clinch River Site***
  Mr. Andrew Kosnaski
  Vice President, Generation Planning, Tennessee Valley Authority

- 2:00 – 2:10 ***Duke Energy's CTCC Sutton Plant***
  Mr. Kevin Murray
  Director, Project Management Center of Excellence,
  Duke Energy, and
  Mr. David Sorrick
  Vice President, Power Generation Operations, Duke Energy

- 2:10 – 2:20 ***Southern Nuclear's AP1000 Reactors at Plant Vogtle Units 3 & 4***
  Mr. Jeffrey Burleson
  Vice President of System Planning, Southern Company

2:20 – 3:20 **Subject Matter Experts: Perspectives on the Session Topic**

- 2:20 – 2:40 ***"Factors Affecting Future Natural Gas Prices"***
  Dr. Alan Krupnick
  Director, Center for Energy Economics and Policy,
  Resources for the Future

- 2:40 – 3:00 ***"ARUDC Rate Regulation and Nuclear Power Are Incompatible!"***
  Dr. Geoffrey Rothwell
  Public Policy Associate Director, Stanford University

- 3:00 – 3:20 ***"Factors that Drive and Limit the Displacement of Coal by Natural Gas"***
  Mr. Stan Kaplan
  Director, Office of Electricity, Renewables, and Uranium Statistics
  U.S. Energy Information Administration

3:20 – 3:40 **Break**

3:40 – 4:40 **Discussion and Q&A: Implications for Future Public Policies**
Panel (all Session II speakers) and participants

4:40 – 5:00 Break

5:00 – 7:00 Reception (with drinks and heavy hors d'oeuvres)

Friday, September 21, 2012

7:45 – 8:30 AM Continental Breakfast

8:30 – 11:45 Session III. Policy Analysis of Safety, Health, Environmental, and National Security Risk Factors

8:30 – 8:40 **Session Purpose**
Session Chair: Dr. Amy Wolfe
Society-Technology Interactions Science Team Leader,
Environmental Sciences Division, Oak Ridge National Laboratory

8:40 – 9:10 **Illustrative Examples: Safety, Health, Environmental, and National Security Risk Considerations**

- 8:40 – 8:50 ***TVA's CTCC John Sevier Plant***
  Mr. Roger Waldrep
  Project Construction Manager, Tennessee Valley Authority

- 8:50 – 9:00 ***Duke Energy's CTCC Sutton Plant***
  Mr. Kevin Murray
  Director, Project Management Center of Excellence,
  Duke Energy, and
  Mr. David Sorrick
  Vice President, Power Generation Operations, Duke Energy

- 9:00 – 9:10 ***TVA's SMR Project at the Clinch River Site***
  Mr. Jeffrey Perry
  Senior Project Manager, Strategic Nuclear Expansion
  Tennessee Valley Authority

9:10 – 10:10 **Subject Matter Experts: Perspectives on the Session Topic**

- 9:10 – 9:30 ***"Minimizing Impacts of Natural Gas Drilling"***
  Mr. Drew Nelson
  Clean Energy Project Manager, Environmental Defense Fund

- 9:30 – 9:50 ***"Federal and State Policies Affecting Nuclear Power's Future"***
  Mr. David Lochbaum
  Director, Nuclear Safety Project, Union of Concerned Scientists

- 9:50 – 10:10 ***"Nuclear Power – the Security Perspective"***
  Dr. Howard Hall
  University of Tennessee and Oak Ridge National Laboratory Governor's Chair Professor of Nuclear Security, and
  Fellow for Global Security Policy, Baker Center

10:10 – 10:30 **Break**

10:30 – 11:30 **Discussion and Q&A: Implications for Future Public Policies**
Panel (all Session III speakers) and participants

11:30 – 11:45 **Symposium Closing and Follow-up**
Dr. Mary English
Fellow for Energy and Environmental Policy, Baker Center

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Symposium Planning Team

Dr. Mary English (Chair)
Fellow for Energy and Environmental Policy, Howard H. Baker Jr. Center for Public Policy;
Senior Fellow, Institute for a Secure and Sustainable Environment, UT

Ms. Alexandra Brewer (Graduate Research Assistant)
Doctoral Student, Department of Political Science, UT

Dr. David Bjornstad
Fellow for Energy and Environmental Policy, Howard H. Baker Jr. Center for Public Policy;
Distinguished Research Staff Member, Environmental Sciences Division, Oak Ridge National Laboratory;
Research Professor, Department of Economics, UT

Ms. Jennifer Brogdon
Senior Manager, Technology Partnerships, Tennessee Valley Authority

Ms. Michelle Castro
Director of Development, Howard H. Baker Jr. Center for Public Policy

Dr. Nissa Dahlin-Brown
Associate Director, Howard H. Baker Jr. Center for Public Policy

Ms. Paula Flowers
Small Modular Reactor Initiative, Oak Ridge National Laboratory

Mr. Michael Ingram
Senior Advisor, Office of the CEO, Tennessee Valley Authority

Ms. Becky Jacobs
Professor, College of Law, UT

Dr. Matthew Murray
Director, Howard H. Baker Jr. Center for Public Policy;
Associate Director, Center for Business and Economic Research;
Professor, Department of Economics, UT

Dr. Robert Shelton
Fellow for Energy and Environmental Policy, Howard H. Baker Jr. Center for Public Policy;
Research Professor, Department of Economics, UT

Dr. Belle Upadhyaya
Professor, Department of Nuclear Engineering, UT

Ms. Elizabeth Woody
Office Manager, Howard H. Baker Jr. Center for Public Policy

Mr. Gregory Zimmerman
Group Leader, Human Health Risk & Environmental Analysis Group, Environmental Sciences Division,
Oak Ridge National Laboratory

Session Chair Biographies

Wes Hines is Professor and Head of the UT Department of Nuclear Engineering, where he also directs the Reliability and Maintainability Engineering program. He has served as Interim Associate Dean for Research in the College of Engineering and more recently as Interim Vice Chancellor for Research for the Knoxville Campus. Dr. Hines teaches and conducts research in artificial intelligence and advanced statistical techniques applied to process diagnostics, condition based maintenance, and prognostics. He has authored over 250 papers and has several patents in the area of advanced process monitoring and prognostics techniques. He has been with UT for 18 years. He is a past nuclear-qualified submarine officer and received an MBA and both an MS and a Ph.D. in Nuclear Engineering from The Ohio State University.

Jake LaRiviere is an assistant professor of Economics at the University of Tennessee. LaRiviere's research focuses on governmental policy toward energy and the environment and subsequent business and consumer behavior. Of particular interest is a firm's response to changes in resource, environmental, and energy policy in addition to optimal regulatory design. LaRiviere is the co-founder of the Baker Center Interdisciplinary Forum on Energy and Environmental Policy.

Amy Wolfe is the Society-Technology Interactions Science Team Leader in Oak Ridge National Laboratory's Environmental Sciences Division. She is the research manager for the Department of Energy's Ethical, Legal, and Social Issues Scientific Focus Area and leads a team of social scientists across three national laboratories focusing on behavioral and institutional change to achieve and maintain federal sustainability goals, in support of DOE's Federal Energy Management Program. Much of Wolfe's work centers on decision processes, implementation, and implications, particularly in the realm of energy, technology, and the environment. She has led efforts to integrate science with decision-makers' needs; incorporate considerations of societal implications into scientific research; and understand conditions that influence technology acceptability. Wolfe has a Masters in Regional Planning and a Ph.D. in Anthropology, both from the University of Pennsylvania.

Speaker Biographies

Michelle Bloodworth is Vice President for State Affairs and Business Development with America's Natural Gas Alliance (ANGA). She works with ANGA's State Affairs Committees as well as utilities, regulators, legislators, and other business-to-business stakeholders to communicate the economic and environmental benefits of using domestic natural gas. Before joining the ANGA team in 2010, she was extensively involved in its creation through her previous position with ANGA member company Energen. She spent more than 20 years with Energen, most recently as Vice President of Marketing, Sales and Communications for Energen's Alabama Gas Corp. She is an officer and founding board member of the Council for Responsible Energy; has served on the boards of the Energy Solutions Center, NGVAmerica, and the Gas Technology Institute's Utilization Technology Development Program; and has been active on committees of the American Gas Association, the Southern Gas Association, and the Southeastern Energy Society. She earned a B.S. in Mechanical Engineering from Auburn University.

Jeff Burleson is Vice President of System Planning at Southern Company. In that role he has responsibility for support to the retail operating companies for integrated resource planning, resource procurement, generation strategy and generation development. Prior to his current position, he was employed by Georgia Power Company as the Director of Resource Policy and Planning, where he had responsibility for the overall generation and supply planning of the Company, including the development of renewable generation and demand side management. He has more than 30 years of experience in the utility business, and has worked at Alabama Power Company, Southern Company Services and Georgia Power Company. Jeff has a Bachelor's degree in Electrical Engineering from the University of Alabama at Birmingham and a Master's degree in Electrical Engineering from Auburn

University. He is a member of the Institute of Electrical and Electronics Engineers (IEEE) and has served on the Energy Policy Committee of IEEE-USA since 1998. Jeff is a registered professional engineer in the states of Alabama and Georgia. He has testified before the Georgia House Energy Subcommittee, and has given testimony numerous times before the Georgia Public Service Commission in regulatory dockets associated with Integrated Resource Plans, approval of demand side resources, and approval of more than 10,000 MWs of new and replacement generation resources including renewable resources and new nuclear units in Georgia.

Jack Cushing is a Senior Project Manager for US Nuclear Regulatory Commission in the Office of New Reactors in the Division of Site Safety and Environmental Analysis. Mr. Cushing graduated from the Massachusetts Maritime Academy in 1979 with a BS in Marine Engineering. Mr. Cushing was a Reactor Operator at Maine Yankee Nuclear Plant from 1985 until 1998. In 1998, Mr. Cushing joined the NRC as a Project Manager. At the NRC, he has been an operating project manager for the Columbia Generating Station, environmental project manager in license renewal and for new reactors. Mr. Cushing has been a contributor to environmental impact statements for Fort Calhoun license renewal, North Anna Early Site Permit and the VC Summer Combined License.

Howard Hall, a nuclear chemist and expert in preventing and responding to nuclear terrorism, directs the Baker Center’s Global Security Program. Hall is also the University of Tennessee-Oak Ridge National Laboratory Governor’s Chair. Dr. Hall earned his doctorate in nuclear chemistry at the University of California, Berkeley. Before coming to UT and ORNL, Dr. Hall worked at Lawrence Livermore National Laboratory (LLNL) as the laboratory’s division leader for radiological and nuclear countermeasures. He was also the program leader for nuclear assessments and forensics and served as the radiological detection and response program leader. While at the LLNL, Dr. Hall worked in partnership with the Department of Homeland Security Science and Technology Directorate. In addition to his role at the Baker Center, Dr. Hall also holds appointments in the nuclear engineering department at UT and the global nuclear security division at ORNL. His focus at ORNL includes ways to detect the presence of and remove from circulation illicit radioactive material and identifying better methods of responding to and recovering from nuclear incidents.

Joe Hoagland is TVA's senior vice president of Policy and Oversight. In this capacity, he is responsible for the areas of retail regulatory affairs, demand side management, technology development, communications, emergency management, corporate security, compliance, and health and safety. He reports to CEO Tom Kilgore. Prior to this appointment, he was vice president and chief of staff, with oversight of the daily operations of the executive office, including board services. He previously served as vice president of Environmental Science, Technology & Policy, and as vice president of Energy Efficiency & Demand Response. He also served as a senior adviser to the CEO. A TVA employee since 1992, he has worked across several organizations within TVA, including managing special projects for TVA's River Systems Operations & Environment organization. He also managed research and development of new power technologies, distributed generation, energy storage, and environmental remediation. Hoagland has served on boards and committees for several industry-related organizations, including the Electric Power Research Institute, the Electricity Storage Association, the U.S. Department of Energy, and the Electric Utility Cost Group. He earned a Bachelor of Science degree in chemistry from Southern Utah University and master's and doctorate degrees in physical chemistry from Washington State University.

Dan Ingersoll is Director of the Office of Research Collaborations for NuScale Power. Dr. Ingersoll joined NuScale in January 2012 to coordinate and develop new R&D activities, including collaborations with national laboratories, universities and industry. Prior to joining NuScale, he was Senior Program Manager in the Small Modular Reactors R&D Office at Oak Ridge National Laboratory where he served as National Technical Director for the U.S. Department of Energy’s Small Modular Reactor program. During his 34 years at ORNL, he participated in several advanced reactor programs, including the Advanced High Temperature Reactor project, the International Reactor Innovative and Secure project, the Space Reactor Technology program, the Advanced Liquid-Metal Reactor program, and the High Temperature Gas-cooled Reactor program. Originally a specialist in radiation physics and transport, he spent over 20 years leading several ORNL research groups conducting radiation transport modeling, reactor shielding experiments and reactor physics analysis.

Revis James is a Director in the Generation research sector of the Electric Power Research Institute. He is responsible for EPRI's research programs in advanced coal generation, CO_2 capture and storage, steam turbine-generators, boiler life & availability, combustion turbines/combine cycles, large scale industry demonstration projects, and water management in power plants. James was previously Director of the Energy Technology Assessment Center, focusing on strategic research and development priorities for the electric power industry based on engineering, economic and policy analysis, and long-term analysis of utility generation asset portfolio planning. James also spent 2½ years in Paris, France leading development of a joint strategic research and development program with Electricité de France. James' responsibilities include extensive communications with federal and state policymakers and regulators. He has been interviewed and cited widely in the media. James earned Bachelor of Science degrees in nuclear engineering, electrical engineering and computer sciences, and a Master of Science degree in nuclear engineering from the University of California, Berkeley. James speaks and writes fluent French.

Stan Kaplan has worked in the energy and environmental areas, focusing on power generation and fuels, since 1978. Prior to rejoining the U.S. Energy Information Administration as Director of the Office of Electricity, Renewables, and Uranium Statistics he was a Specialist in Energy and Environmental Policy with the Congressional Research Service. Immediately before joining CRS, Stan was a team leader managing electric power survey data collection and analysis at the EIA. He has otherwise worked for energy consulting firms, including Fieldston Company and PHB Hagler Bailly; for regulatory agencies, including the Texas Public Utility Commission; and served as manager of fuel supply for Austin Energy, the municipal utility serving Austin, Texas.

Andrew Kosnaski was named TVA's Vice President of System Planning in February, 2010. In this role, he is responsible for all generation planning activities at TVA, including capacity expansion to ensure TVA has the generating resources it needs to meet future demand. Kosnaski is also responsible for supporting TVA's short- and long-term financial plans, capital budgeting, outage planning, and transmission strategy. From 2007 to 2010, Kosnaski served as TVA's Vice President of Financial Planning and Enterprise Risk Management, where he was responsible for developing TVA's long-range financial plans, overseeing the development of an Enterprise Risk Management Program at TVA, and managing the risk oversight and control function related to TVA's financial risk management activities. Prior to joining TVA in 2007, he had served as Manager of Risk Management and Analytics with the Southern Company in Atlanta and as a Risk Manager on Southern's wholesale energy trading floor. Other prior work experience includes serving as an economist with the New Hampshire Public Utilities Commission, where he assisted in restructuring that state's retail electricity markets; as Senior Economic Advisor to the Leader of the Official Opposition in the Canadian House of Commons; and as a Risk Manager at Enron Wholesale Services specializing in the New England bulk power markets and large structured transactions. Kosnaski has Bachelor's degrees in economics as well as political science and government from Carleton University in Ottawa, Canada, and a Master's degree in Business with a finance concentration from the University of Alabama at Birmingham. He also has done graduate studies in finance at the University of Ottawa.

Alan Krupnick is Director of Resources for the Future's Center for Energy Economics and Policy (CEEP), as well as a Senior Fellow at RFF. He currently heads a study on the risks associated with shale gas development and regularly researches issues on natural gas and broader concerns about national energy policy as applied to the transportation and power sectors. Alan has been a consultant to state governments, federal agencies, private corporations, the Canadian government, the European Union, the World Health Organization, and the World Bank. He co-chaired an advisory committee that counseled the U.S. Environmental Protection Agency on new ozone and particulate standards. Krupnick also served as senior economist on the President's Council of Economic Advisers, advising the Clinton administration on environmental and natural resource policy issues. He is a regular member of expert committees from the National Academy of Sciences and the U.S. EPA. He received his Ph.D. in Economics from the University of Maryland.

Dave Lochbaum is the Director of the Nuclear Safety Project for the Union of Concerned Scientists. He graduated with a nuclear engineering degree from The University of Tennessee in 1979 and worked in the nuclear power industry for over 17years. Lochbaum joined UCS in fall 1996 and is primarily focused on the safety levels of the nation's 104 operating nuclear power reactors. He presents UCS's perspectives to the Nuclear Regulatory Commission, Congressional oversight committees, state and local officials, media representatives, and citizens.

Kevin Murray is a power industry professional with 20 years of experience. Kevin started his career with Westinghouse Power Generation (now Siemens) in Orlando and he then moved to Houston to work for El Paso Corporation. He has been involved with power projects in the US, Asia and South America, including a 1 year residency in Brazil. Mr. Murray received his B.S. degree in Mechanical Engineering from the University of Arizona. Currently, he is a Director with Duke Energy in the Project Management & Construction Department, which has over $13B in power projects underway.

Drew Nelson is a Clean Energy Project Manager at Environmental Defense Fund. Most of his work is focused on issues relating to natural gas drilling, including efforts to minimize the negative impacts of drilling in communities. Prior to joining EDF, he worked for the U.S. Department of State on the international climate negotiations. At the State Department, he was the lead negotiator on a variety of issues, including deploying clean technologies, reducing emissions from international aviation, and developing international sustainability criteria for biofuels. He also worked previously at the U.S. Environmental Protection Agency in its Office of Air and Radiation. He has a joint masters in Policy and Latin American Studies from the University of Texas, with a concentration in environmental policy.

Jeff Perry is the Senior Project Manager for the Clinch River Construction Permit Project in the TVA Small Modular Reactor Technology organization. Mr. Perry is responsible for managing activities associated with the small modular reactor project on the Clinch River site. Mr. Perry has 20 years of experience in the nuclear industry with background in project management, environmental cleanup, waste management, and the National Environmental Policy Act. Prior to joining TVA, he worked for the Department of Energy at the Idaho National Laboratory, where he was most recently the project manager for the Decontamination, Deactivation, and Demolition of the Experimental Breeder Reactor – II, sodium-cooled reactor. He holds a Bachelor's Degree in Mechanical Engineering from the University of Texas at Austin.

Geoffrey Rothwell is a Senior Lecturer and the Director of Honors Programs in the Department of Economics, Stanford University, and Associate Director of Stanford's Public Policy Program. Since 2001, he has been the chief economist of the Economic Modeling Working Group of the Generation IV International Forum through the U.S. Department of Energy, Office of Nuclear Energy. He has worked for ANL, INL, LLNL, ORNL, and PNNL. Dr. Rothwell has written extensively on the economics of nuclear power and electricity regulation. His book with Tomas Gomez, *Electricity Economics: Regulation and Deregulation* was published in 2003 by IEEE Press with John Wiley. His research has been published many journals, including *Energy Economics, Energy Policy, Energy Journal*, *Journal of Econometrics*, *Journal of Risk and Uncertainty*, *Resources and Energy*, *Review of Economics and Statistics*, and *Science & Global Security*. He graduated from high school in Richland, Washington. He received his M.A. in 1984 in Jurisprudence and Social Policy from Boalt Law School, University of California, Berkeley, and his Ph.D. in 1985 in Economics from the University of California, Berkeley. After a Post-Doctoral Fellowship at the California Institute of Technology, he has been teaching and doing research at Stanford since 1986.

David Shammo is vice president of business development for Spectra Energy's Southeast operations. He holds lead commercial accountability for Gulfstream Natural Gas System, a joint development between Williams and Spectra Energy, and for Southeast Supply Header, Spectra Energy's joint venture with CenterPoint Energy. He also is responsible for furthering the company's business development focus on power generation opportunities in the Southeast United States. Before assuming his current position in September 2011, he served as general manager of business development, Southeast for Spectra Energy, and vice president of Gulfstream Natural Gas and Southeast Supply Header. He joined the company in 1981 as a performance measurement analyst and has held positions of increasing responsibility in the areas of project performance, accounting, marketing and business development. He earned a Bachelor of Science degree in business administration from the University of Akron.

David Sorrick is the vice president of Power Generation in North Carolina for Duke Energy. (He was with Progress Energy before its July 2012 merger with Duke Energy.) In his role, he oversees the operation of the company's fleet of coal, oil, and natural gas-fired power plants in North Carolina. He joined Progress Energy in 1988 as an engineer and worked his way up through several engineering and management positions, including director of Combustion Turbine Services and general manager of Fossil Operations in Florida. He has more than two decades of expertise, including combustion turbine and fossil plant operation and maintenance, new unit startup and commissioning, project management of power plant construction and upgrades, and labor contract negotiations and administration. He earned a bachelor of science degree in electrical engineering from University of Tennessee at Chattanooga, and a master's in business administration from the University of South Florida. He is a registered professional engineer.

Rob Steele is a Program Manager at the Electric Power Research Institute in Charlotte, North Carolina, of the Combined-Cycle Turbomachinery program (P79). Prior to joining P79, Dr. Steele focused on IGCC gas turbine syngas applications, new oxygen separation technologies, and advanced laser techniques for measuring gasifier flame temperatures. He has particular expertise in the area of CO_2 handling with emphasis on advanced compression, power plant integration, thermophysical properties of CO_2 mixtures, and pipeline transportation. Dr. Steele has twenty-five years' experience in gas turbine combustion research, development and testing; and electric power generation industry including carbon capture, compression and sequestration. Prior to joining EPRI, Steele was a Vice President and Combustion Team Leader at Ramgen Power Systems in Bellevue, Washington. He was directly involved in the development of lean premixed trapped vortex combustion designs for gas turbines and supersonic compressor designs for industrial gas compression applications with specific focus on CO_2. Of note, he also worked at Solar Turbines in San Diego as the Mars SoloNOx Engine Combustion Team Leader.

Dan Stout joined the Tennessee Valley Authority in April 2009. He currently serves as a Senior Manager in the Technology Innovation organization responsible for managing TVA's Small Modular Reactor project. He previously was responsible to TVA's Federal Programs, including tritium production, MOX fuel utilization, and advanced modeling & simulation of light-water reactors. Before joining TVA, he served as Director, Nuclear Fuel Recycling, at the U.S. Department of Energy where he was responsible for planning and policy development regarding nuclear fuel recycling. He was the lead interface with industry working under Cooperative Agreements with DOE in support of the Global Nuclear Energy Partnership, as well as the primary interface with the U.S. Nuclear Regulatory Commission. From 1991 to 2006 he worked in the uranium enrichment industry, predominantly at USEC Inc. where he was Director of Advanced Technology. From 1985 to 1991 he served in the U.S. Navy as a nuclear submarine officer; from 1991 to 2007 he served in the Naval Reserves in the Naval Special Warfare community, retiring as a Commander. He graduated from the U.S. Naval Academy in 1985 and received his Master's Degree in Engineering Management from the National Technological University in 1997.

Roger Waldrep joined the Tennessee Valley Authority in 1993 and currently works as Senior Manager, New Unit Services, Construction Projects. Over his career at TVA he has held numerous positions at the Chattanooga corporate offices and was Engineering Manager at an operating power plant. He joined his current work group, New Unit Services, in October of 2007. This work group provides management and oversight for the many activities associated with all non-nuclear new and replacement generation at TVA. In this position he is responsible for the design, procurement, and construction of simple-cycle and combined-cycle gas turbine facilities. Most recently he served as the Project Manager for the new John Sevier Combined Cycle Plant. He received a Bachelor's degree in Electrical Engineering from the University of Alabama in Tuscaloosa in 1993. He is a certified PMP (Project Management Professional) and maintains affiliation with PMI (Project Management Institute). He resides in Chattanooga with his wife and two sons.