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Designing CO_2 Performance Standards for a Transitioning Electricity Sector: A Multi-Benefits Framework

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EXECUTIVE SUMMARY

The U.S. electricity sector is in the midst of a significant transition driven by changes in markets, technology, and regulation, including

- Retirement of a large number of coal-fired power plants in a relatively short period;
- Increasing reliance on natural gas generation and potentially increasing exposure to fuel price volatility;
- Uncertainty about the amount of nuclear capacity available after 2030, when licenses for approximately one-third of that capacity will begin to expire, and the near-term need to determine whether to begin taking steps to renew those licenses;
- Uncertainty about future electricity demand growth and the simultaneous need to finance significant capital expenditures for emissions control retrofits and new generation;
- Potentially reduced sales and revenues due to growth of demand-side resources such as distributed solar; and
- Uncertainty about the impacts of upcoming environmental regulations and policy.

This transition, and the pace at which it is occurring, presents a number of challenges for state utility regulators as they evaluate cost-effective options for managing short-term and long-term risks. Coinciding with these challenges, state environmental regulators will soon have an obligation under section 111(d) of the Clean Air Act to develop performance standards to limit carbon dioxide (CO_2) emissions from the existing fleet of fossil fuel-fired power plants. Responses to these issues will affect electricity prices and environmental impacts for years to come.

The flexibility embedded in section 111(d) creates an opportunity for utility commissioners, state environmental officials, and other state-level policy makers to take a more holistic view of the electricity sector and factors that will affect electricity rates and reliability as well as public health. In particular, state regulators can seek strategies that achieve multiple benefits for electricity generators and consumers, such as reducing CO_2 emissions while also addressing the emerging risks and challenges described above. For example, energy efficiency may reduce dispatch at fossil fuel-fired facilities, thereby reducing CO_2 emissions, while also allowing electric utilities to forestall building new generation facilities. Similarly, new renewable energy investments may satisfy section 111(d) requirements while also helping to increase diversity in the generation mix and hedging against the risk of more stringent air quality standards in the future. The electricity sector varies from state to state, so identifying multi-benefits strategies to comply with environmental regulations and address other challenges will likely require an increased level of coordination among energy regulators and environmental regulators.

INTRODUCTION

The U.S. electricity sector is in the midst of a significant transition. Low natural gas prices, driven by the rapid expansion of shale gas production using hydraulic fracturing and horizontal drilling, have led to a shift toward natural gas-fired electricity generation.[1] The shale gas boom occurred at the same time that the U.S. Environmental Protection Agency (EPA) promulgated new rules to limit hazardous air pollutants as well as rules to limit downwind transport of sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter, intensifying economic pressure on coal-fired power plants operating without adequate pollution control technologies.[2] The combination of these factors is causing power plant operators to

[1] *Evaluating the Role of FERC in a Changing Energy Landscape: Hearing before the Subcomm. on Energy and Power of the Comm. on Energy and Commerce*, 113th Cong. (2013) (written testimony of John R. Norris, Commissioner, FERC), *available at* http://www.ferc.gov/CalendarFiles/20131205094304-Norris-12-05-2013.pdf ("Significant change is occurring in the energy sector. This change is driven by a new, abundant supply of natural gas; technological innovations in grid operations, renewable energy and energy efficiency; and public policy initiatives and environmental regulations.").
[2] Mercury and Air Toxics Standards, 77 Fed. Reg. 9304, 9367–70 (Feb, 16, 2012) (codified at 40 C.F.R. pts. 60, 63);

choose whether to retire older coal-fired units, retrofit them with new pollution control technologies, or convert them from coal to natural gas generation.

These trends have had a major impact on the coal sector, but coal-fired power plants are not the only facilities facing a new economic reality. Low natural gas prices and, in some markets, increasing wind generation are also creating economic pressure on nuclear power plants[3]—a situation that would have seemed highly unlikely only a few years ago. Together, relatively flat electricity demand and inexpensive photovoltaic panels are challenging the utility business model by shrinking revenues from electricity sales.[4] In addition to these economic, technical, and regulatory shifts, the EPA proposed new source performance standards (NSPSs) to limit carbon dioxide (CO_2) emissions from new coal-fired and natural gas-fired power plants. The agency is in the process of developing guidelines under section 111(d) of the Clean Air Act to limit CO_2 emissions from existing coal-fired and natural gas-fired facilities.

Viewed in isolation, limiting CO_2 emissions from the existing fleet of coal and natural gas-fired power plants could add to the growing list of challenges facing regulators and power plant operators. With deliberate planning, however, compliance strategies to reduce CO_2 emissions from the power sector may also address numerous other electricity sector risks. Much of this potential is rooted in the statutory language of section 111(d), which could provide a range of flexible compliance options to state regulators.

This report explores the options for addressing electricity sector challenges while also implementing strategies to reduce CO_2 emissions. It starts with a general discussion of the roles of state-level environmental regulators and utility commissions and the near-term decisions that will determine the structure of the electricity sector in the future. Subsequent sections describe economic, technical, and regulatory factors facing the sector and provide an overview of section 111(d) of the Clean Air Act and the regulatory compliance options that may be available to the states to limit CO_2 emissions from existing fossil fuel-fired facilities. The report concludes by outlining section 111(d) compliance strategies that could help mitigate the other challenges facing the electric power sector.

STATE-LEVEL REGULATION OF THE ELECTRICITY SECTOR

State regulatory agencies overseeing the electricity sector typically have distinct mandates: utility commissions generally focus on consumer protection and reliability concerns, whereas state environmental agencies focus on protecting public health and the environment. In some states, energy offices oversee energy efficiency and renewable energy policies. Together, these agencies will grapple with many difficult choices in the next few years, including:

- How important is it for the state to maintain diversity in the fuel mix and what are the viable options for achieving the desirable mix?
- How will increased end use efficiency and distributed generation affect forthcoming capital investments and revenues to pay for these investments?
- How should the potential impacts of nuclear retirements due to market forces and expiring operating licenses be assessed and the potential for stranded investments be considered?
- How should regulators design performance standards that limit CO_2 emissions from the existing fleet of fossil fuel-fired power plants?

Cross-State Air Pollution Rule, 76 Fed. Reg. 48,208, 48,208 (codified at 40 C.F.R. pts. 51, 52, 72, 78, 97).

[3] Kathleen L. Barrón, Bipartisan Policy Center: GHG Regulation of Existing Power Plants (Dec. 6, 2013), http://bipartisanpolicy.org/sites/default/files/Barron%20Dec%206%20Workshop.pdf.

[4] Peter Kind, EDISON ELECTRIC INST. DISRUPTIVE CHALLENGES: FINANCIAL IMPLICATIONS AND STRATEGIC RESPONSES TO A CHANGING RETAIL ELECTRIC BUSINESS (Jan. 2013).

The answers to these questions will affect the makeup of the electricity sector for years to come. Inadequately hedging against emerging market risks and the potential for technological and regulatory developments could result in increased electricity prices. Ensuring an affordable, reliable, and clean electricity sector will therefore require not only understanding the range of challenges in isolation, but also how they interact with one another. For example, there are numerous strategies available to maintain diversity in the fuel mix and numerous options to reduce CO_2 emissions from the electric power sector. Some, but certainly not all, choices could achieve both goals. The emergence of these challenges in a relatively short timeframe presents state regulators with an opportunity to take a more holistic view of the electricity sector and factors that will affect electricity rates and reliability as well as public health. In particular, the rulemaking process that is under way to limit CO_2 emissions from the existing fossil fuel-fired fleet will likely result in a range of options available to state regulators as they design performance standards for the sector. The flexibility embedded in the applicable section of the Clean Air Act—section 111(d) (described in detail below)—may allow state regulators to identify options that satisfy the broadest range of policy goals.

CHALLENGES FACING THE ELECTRICITY SECTOR

The electricity sector is facing a multitude of challenges, including:

- Retirement of a large number of coal-fired power plants in a relatively short time period;
- Increasing reliance on natural gas generation and potentially increasing exposure to fuel price volatility;
- Uncertainty about the amount of nuclear capacity available after 2030, when licenses for approximately one-third of that capacity will begin to expire, and the near-term need to determine whether to begin taking steps to renew those licenses;
- Uncertainty about future electricity demand growth and the simultaneous need to finance significant capital expenditures for emissions control retrofits and new generation;
- Potentially reduced sales and revenues due to growth of demand-side resources such as distributed solar; and
- Uncertainty about the impacts of upcoming environmental regulations and policy.

Retiring Older Coal-Fired Power Plants

Forthcoming regulation of emissions from existing coal units, most notably the Mercury and Air Toxics Standard (MATS), and the shifting economic outlook due to low natural gas prices have forced owners of uncontrolled coal plants to decide whether to make major investments in emissions control technology or to retire their plants.[5] Before implementation of MATS, most uncontrolled coal units in the United States were more than 40 years old, had less than 200 megawatts (MW) capacity, and had relatively high heat rates. Environmental retrofit costs tend to be higher per unit of capacity for smaller units (<300 MW) than for larger units.[6] The U.S. Energy Information Administration (EIA) projects that 60 gigawatts (GW) of coal-fired capacity—19% of 2010 coal capacity—will retire by 2020.[7] Approximately 90% of projected plant closures will occur by 2016, when remaining coal units must comply with the emissions limits established under MATS. This rapid retirement of this segment of traditional base load capacity will cause a significant shift for the electricity sector.

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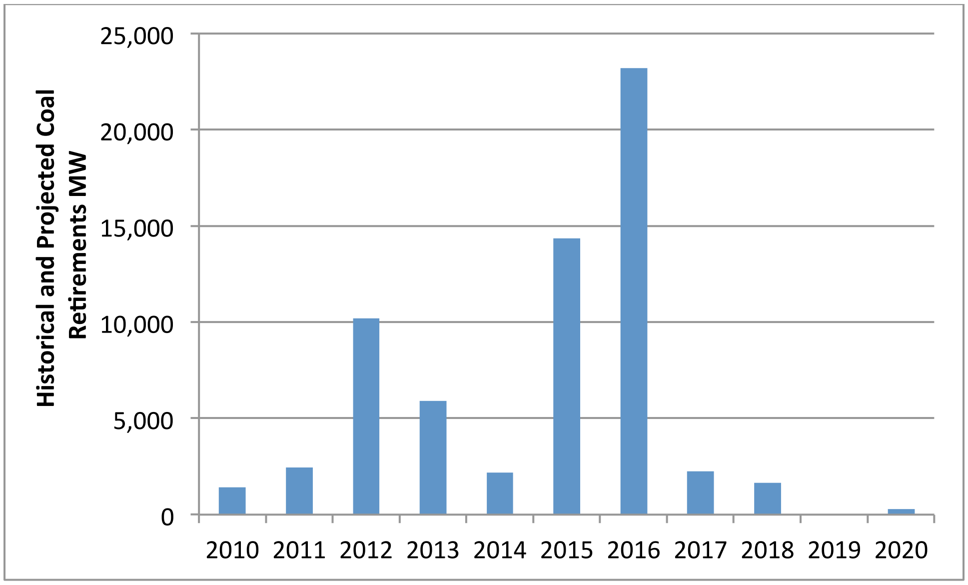
[5] Jennifer Macedonia, *et al.*, BIPARTISAN POL'Y CTR., ENVIRONMENTAL REGULATION AND ELECTRIC SYSTEM RELIABILITY (2011).

[6] Jennifer Macedonia & Colleen Kelly, BIPARTISAN POL'Y CTR., PROJECTED IMPACTS OF CHANGING CONDITIONS ON THE POWER SECTOR (July 2012).

[7] U.S. EIA, *Today in Energy: AEO 2014 projects more coal-fired power plant retirements by 2016 than have been scheduled* (Feb. 14, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=15031; U.S. EIA, ANNUAL ENERGY OUTLOOK 2013 (Apr. 2013) (*hereinafter* AEO 2013).

Figure 1. Historical and Projected Coal Retirements.



Source: U.S. EIA, *Today in Energy,* http://www.eia.gov/todayinenergy/detail.cfm?id=15031.

Energy projections suggest it is highly unlikely that utilities will replace this retiring generation with new coal-fired power plants. For example, in its Annual Energy Outlook 2014 Early Release, which does not reflect EPA regulations restricting electricity sector CO_2 emissions, the U.S. Energy Information Administration (EIA) projects less than 0.5 GW of new coal capacity through 2040.[8]

Expanding Natural Gas Generation and the Risk of Increased Exposure to Price Volatility

Expanding Natural Gas Generation

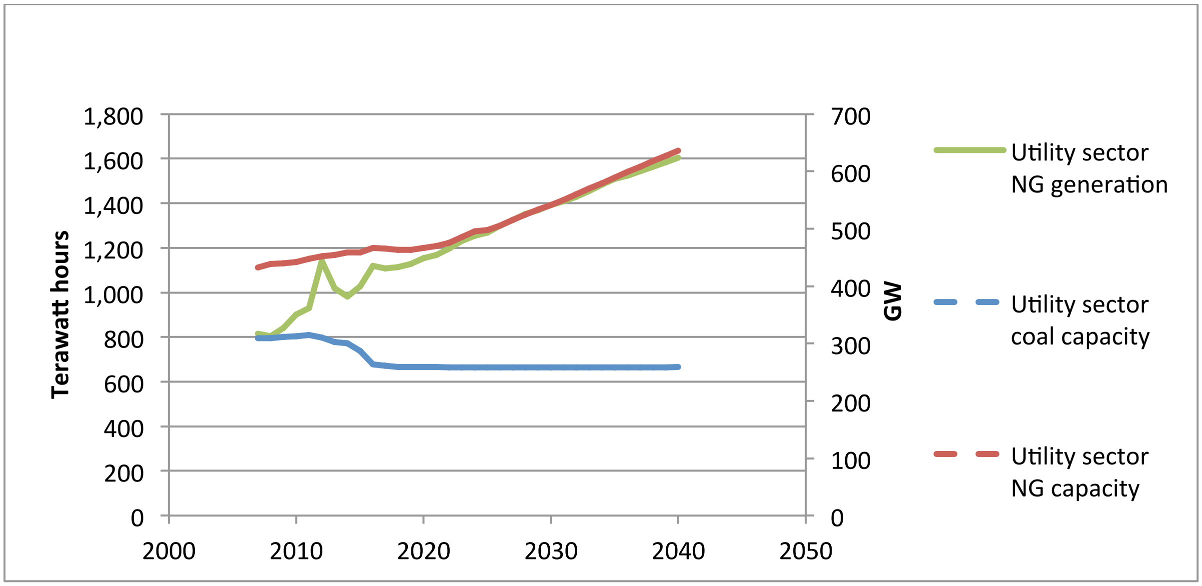
In light of low natural gas prices due to increasing production from shale gas resources, retiring coal capacity, and the low costs of constructing new natural gas generation, relative to other generation technologies, the U.S. electric power sector is increasing its dependence on natural gas generation.[9] Natural gas generation is projected to increase approximately 28% by 2020 relative to 2010, and EIA's Annual Energy Outlook 2014 Early Release projects a 37.3 GW increase in new natural gas capacity through 2020 and a decrease in coal capacity.[10]

[8] The total unplanned coal capacity additions amount to 0.5 GW. Planned coal capacity additions, representing ongoing capacity additions that the EIA uses as an input into its projections, are 2.2 GW in the AEO 2014 Early Release. U.S. EIA, ANNUAL ENERGY OUTLOOK 2014 EARLY RELEASE (Feb. 2014) (*hereinafter* AEO 2014 EARLY RELEASE).

[9] AEO 2013, *supra* note 8.

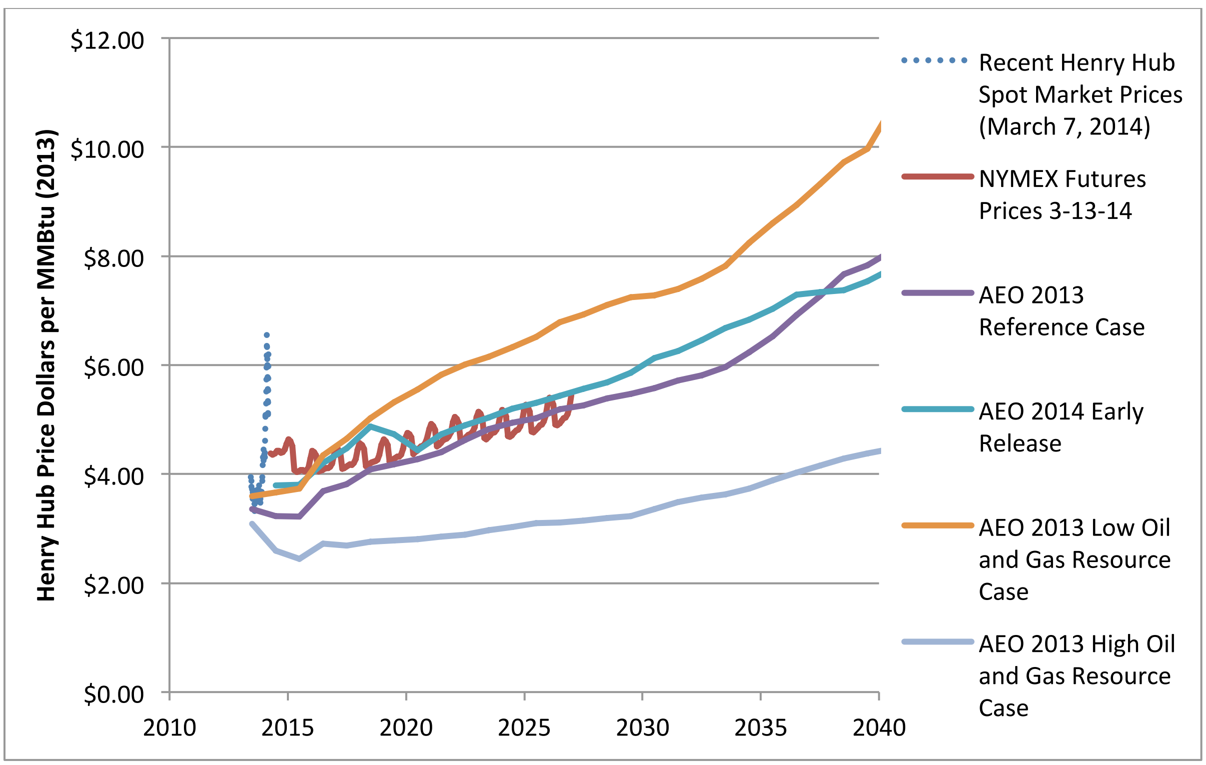
[10] Capacity additions include all natural gas combined cycle units and oil and gas combustion turbine units. U.S. EIA, AEO 2014 EARLY RELEASE, *supra* note 9.

Figure 2. U.S. Utility Sector Natural Gas Generation and Capacity.



Source: EIA Annual Energy Outlook 2014 Early Release.
Note: Data prior to 2010 are from 2010, 2011, and 2012 EIA annual energy outlooks. Natural gas capacity includes oil and gas steam units, combined cycle units, and combustion turbines.

Figure 3. Recent Henry Hub Natural Gas Spot Market Prices (Weekly), NYMEX Henry Hub Futures Prices, and EIA AEO 2013 and AEO 2014 Early Release Henry Hub Natural Gas Price Projections.



In this environment of projected low natural gas prices corresponding to increased production, utilities and utility regulators can easily consider gas the best option to meet new capacity needs. Table 1 shows EIA's 2013 estimate for the levelized cost of new generation coming online in 2018. New natural gas generation is the least-cost resource, on the order of one-third less than other dispatchable generation options.

Table 1. U.S. Average Levelized Costs (2011 $/megawatthour) for Plants Entering Service in 2018.

Plant type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced coal with CCS	85	88.4	8.8	37.2	1.2	135.5
NG combined cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced NGCC with CCS	87	34	4.1	54.1	1.2	93.4
Advanced NG combustion turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced nuclear	90	83.4	11.6	12.3	1.1	108.4
Biomass	83	53.2	14.3	42.3	1.2	111
Wind[a]	34	70.3	13.1	0	3.2	86.6
Solar PV[a,b]	25	130.4	9.9	0	4	144.3

[a]Does not include state and federal tax incentives.
[b]Costs are expressed in terms of net alternating current power available to the grid for the installed capacity.

A comparison of EIA's levelized cost for new generation in Table 1 with the levelized cost estimates for a low-heat-rate combined cycle unit (shown in Table 2) shows that natural gas prices would need to more than double current NYMEX futures prices to make other dispatchable resources cost competitive with new combined cycle generation.[11]

[11] EIA cost assumptions are based on a national average. EIA modeling assumes that heat rates improve as technology is further developed and deployed. For this example, the Nth-of-a-kind heat rate is used to represent a low-heat-rate combined cycle unit coming online in 2018. An Nth-of-a-kind heat rate represents EIA's estimate of future heat rates as technology matures and is widely deployed and utilized. U.S. EIA, ASSUMPTIONS TO THE ANNUAL ENERGY OUTLOOK 2013: ELECTRICITY MARKET MODULE (2013), *available at* http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.

Table 2. Levelized Cost of New Natural Gas Combined-Cycle Generation Entering Service in 2018.

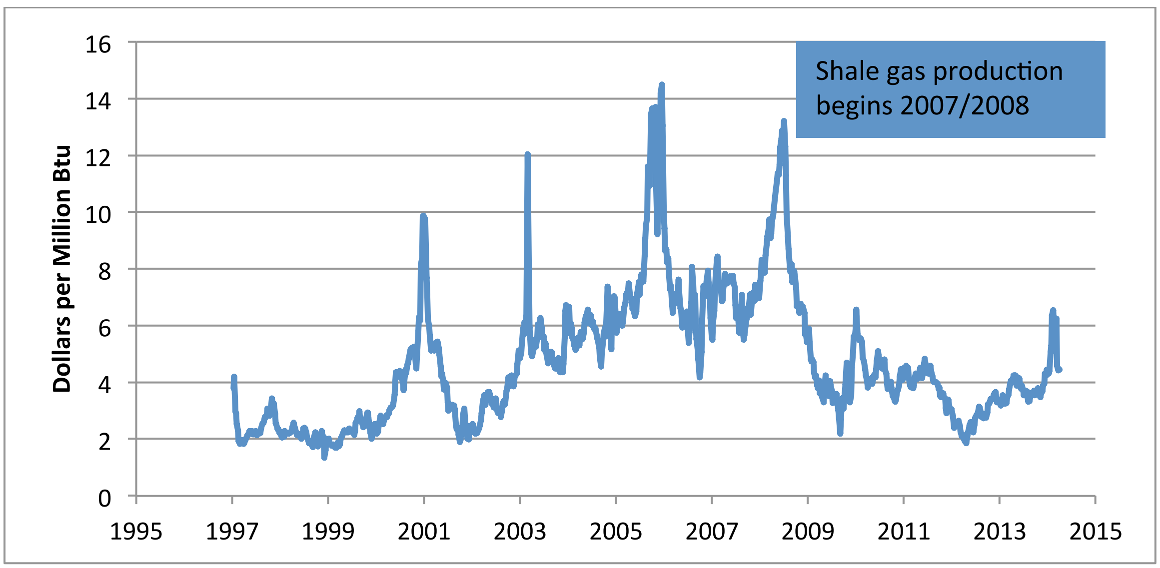
	$5/ MMBtu	$6/ MMBtu	$7/ MMBtu	$8/ MMBtu	$9/ MMBtu	$10/ MMBtu	$11/ MMBtu	$12/ MMBtu
NGCC	56.24	63.04	69.84	76.64	83.44	90.24	97.04	103.84

Note: Cost is based on EIA assumptions and a low (Nth-of-a-kind) heat rate.

Risk of Increased Exposure to Price Volatility

Historically, natural gas prices have shown significant volatility relative to coal prices.[12] Projections of recoverable domestic natural gas supply in the United States have increased significantly due to the new accessibility of shale gas resources, and EIA projects increasing domestic on-shore natural gas production and reduced imports.[13] In theory, these trends should reduce natural gas price volatility, but projecting future natural gas prices is difficult. Since 2008, when shale production began to increase, natural gas spot prices have decreased in volatility relative to 1997–2007 prices (Figure 4).

Figure 4. Historical Weekly NYMEX Spot Prices January 1997 through March 2014.



Source: Data from http://www.eia.gov/dnav/ng/hist/rngwhhdw.htm.

Increased reliance on natural gas generation coupled with a return to past volatility would create significant price risk for consumers.[14] Additionally, during this period of low gas prices, it is generally assumed that there is more upside than downside price risk. Despite low natural gas price projections, the combination of coal retirements, increasing natural gas capacity, and projections for additional natural gas facilities has created concern among some utilities and utility regulators about over-reliance on natural

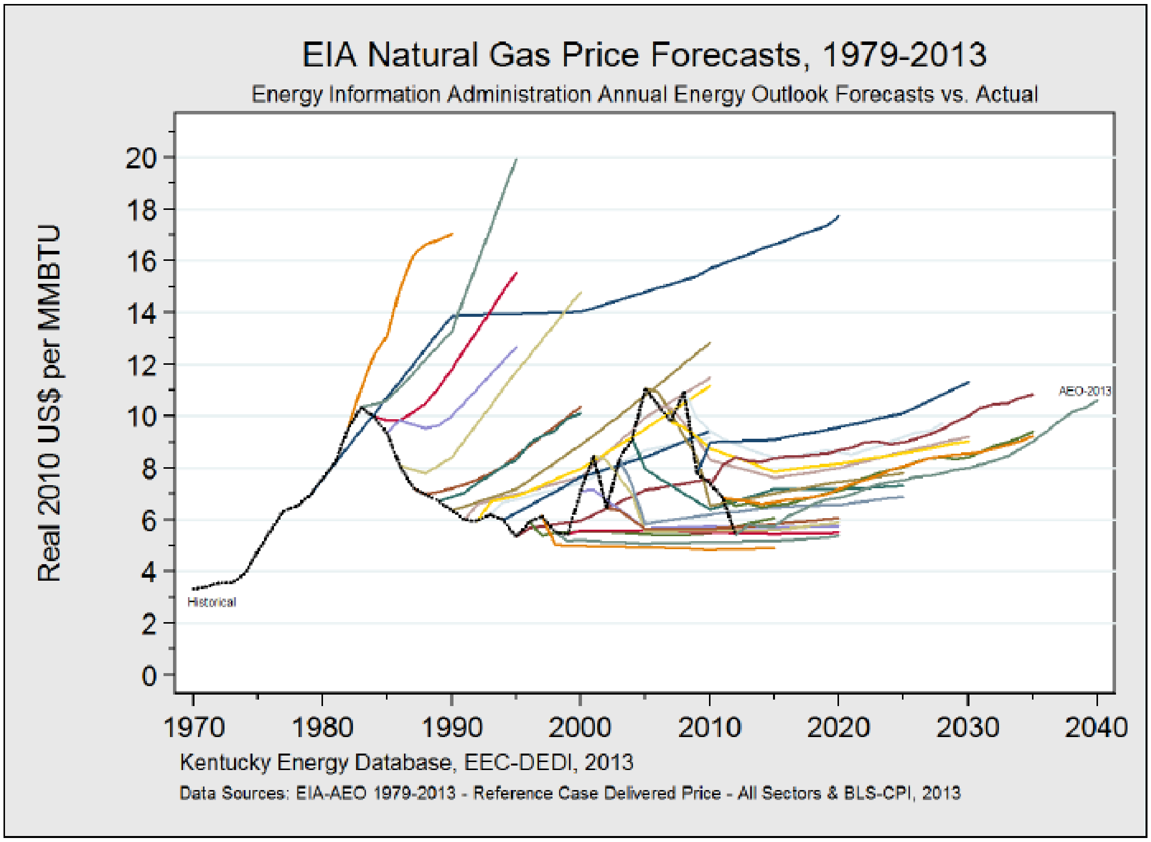
[12] Historical coal prices are available at http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0709. Historical natural gas prices are available at http://www.eia.gov/dnav/ng/hist/n9190us3m.htm.

[13] Potential Gas Committee, *Potential Gas Committee Reports Significant Increase in Magnitude of U.S. Natural Gas Resource Base* (Apr. 9, 2013), http://potentialgas.org/press-release. AEO 2013, *supra* note 8.

[14] Mark Bollinger, LAWRENCE BERKELEY NAT'L LAB., REVISITING THE LONG-TERM HEDGE VALUE OF WIND POWER IN AN ERA OF LOW NATURAL GAS PRICES, LBNL-6103E (Mar. 2013).

gas generation.[15] As Figure 3 shows, the range of natural gas price projections increases over time, and projections of natural gas prices have consistently proven to be incorrect (Figure 5).

Figure 5. Historical Natural Gas Spot Prices and EIA Natural Gas Price Projections from the Annual Energy Outlook.



Source: Economic Challenges Facing Kentucky's Electricity Generation Under Greenhouse Gas Constraints, Commonwealth of Kentucky Energy and Environment Cabinet, December 2013.
Note: The black line shows historical Henry Hub spot prices, and the colored lines shows past EIA projections.

New natural gas combined cycle and combustion turbine units are generally assumed to have an operating life of 30 years, well beyond the scope of NYMEX futures markets.[16] If natural gas units were to operate at high use rates during periods of high natural gas prices, ratepayers would likely see corresponding increases in electricity prices. If there were more non-gas dispatch options during these periods, the price pressure would decline.

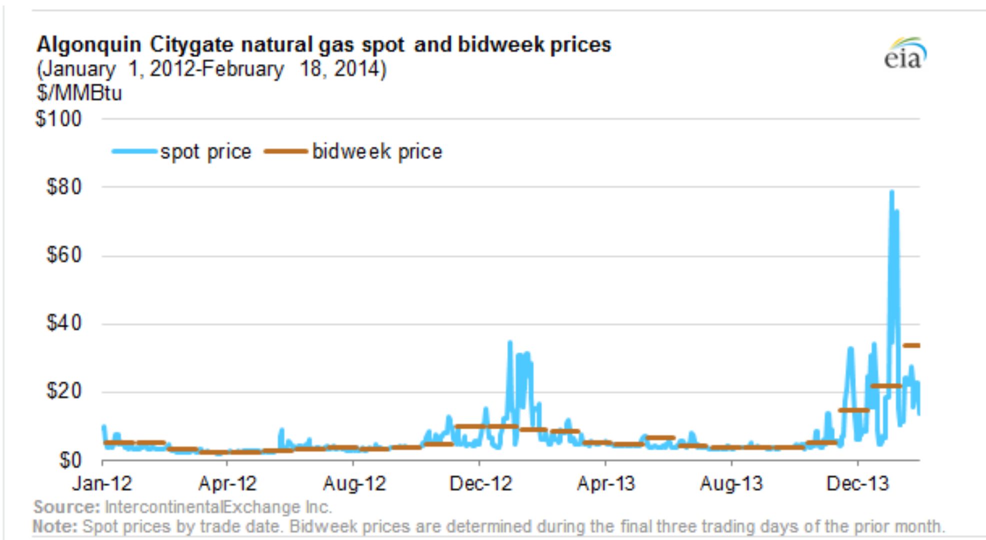
Natural gas prices and supplies can also face local constraints, especially during cold weather periods, when natural gas demand for heating increases and pipelines reach their capacity. As Figure 6 shows, natural gas prices in New England increased significantly in January and February 2014 as cold weather

[15] Brian Wingfield, *Duke Energy Chief Urges U.S. Caution in Relying on Natural Gas*, BLOOMBERG, May 19, 2011, http://www.bloomberg.com/news/2011-05-19/duke-energy-chief-urges-u-s-caution-in-relying-on-natural-gas.html; and Phyllis Reha, *The Role of Natural Gas in Minnesota's Energy Future* (presentation at the Environmental Initiative Policy Conference, Concordia University, Sept. 21, 2012), http://www.slideshare.net/Environmental-Initiative/policy-forum-series-reha-the-role-of-natural-gas-in-minnesotas-energy-future.

[16] EPA modeling of the electricity sector assumes a 30-year book life (useful life) for new natural gas generation. *See* EPA's Power Sector Modeling Platform Documentation for v.5.13, Chapter 8: Financial Assumptions, http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_8.pdf (last visited Apr. 15, 2014).

increased demand for natural gas for heating and pipeline constraints limited supply into the region.[17] As a result of high natural gas prices and increased demand, spot electricity prices exceeded $600/MWh at the New England ISO regional hub, with average prices of $169/MWh in January 2014 and $161/MWh from February 1 to February 18. For comparison, prices at the same hub averaged $45/MWh in November 2013.[18] But as Figure 3 shows, natural gas futures prices (NYMEX) remain in the $4–$5/MMBtu range despite these recent price spikes in the northeastern United States and are consistent with near-term projections from EIA.[19] Nonetheless, these spikes demonstrate that some regions may be vulnerable to local price shocks. Natural gas-dependent regions can reduce local constraints by adding transportation capacity and are actively doing so. For example, the northeast region is adding pipeline capacity and planning additional capacity.[20]

Figure 6. Algonquin Citygate Natural Gas Prices.



Source: U.S. EIA, *Today in Energy: New England Spot Prices Hit Record Levels This Winter*, Feb. 21, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=15111#.

Pending Nuclear Retirements

Nuclear power provides approximately 20% of the electricity generation in the United States.[21] But the existing fleet of nuclear plants is aging; many units are approaching the end of their 20-year operating license extension (60 years total).[22] Although the Nuclear Regulatory Commission has begun the process

[17] U.S. EIA, *Today in Energy: New England Spot Prices Hit Record Levels this Winter*, Feb. 21, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=15111#.

[18] *See* ISO New England, Selectable Day-Ahead and Real-Time Hourly LMP Data, http://www.iso-ne.com/markets/hrly_data/selectHourlyLMP.do. Day ahead hourly price for the NEISO Internal Hub on January 23, 2014, reached $688/MWh. *See id.*

[19] CME Group, Natural Gas (Henry Hub) Physical Futures Settlements, Mar. 14, 2014, http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html; AEO 2014 Early Release, *supra* note 9; AEO 2013, *supra* note 8. Cyclical increases in NYMEX futures prices are due to increased winter demand. U.S. EIA, *Today in Energy: Natural Gas Consumption Has Two Peaks Each Year*, July 1, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=2050.

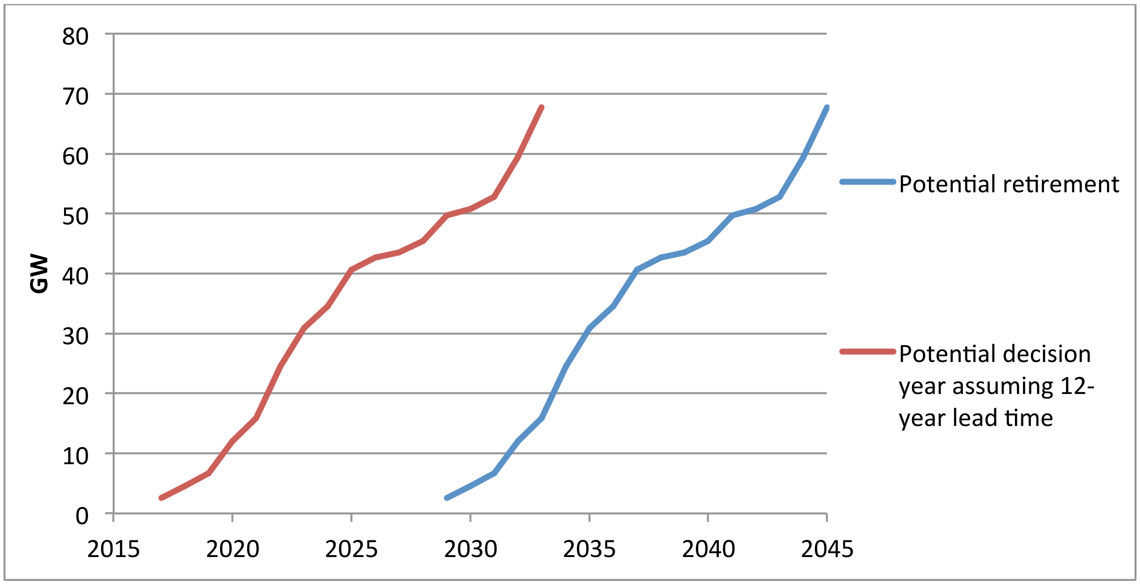
[20] Natural Gas Assoc., Planned Enhancements, Northeast Natural Gas Pipeline Systems (as of 3-13-14), http://www.northeastgas.org/pdf/system_enhance0314.pdf.

[21] AEO 2013, *supra* note 8.

[22] Based on data from U.S. EPA's National Electric Energy Data System (NEEDS) v.4.10 database, *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html.

of considering a second operating license extension, the number of units that will apply for and the costs of complying with the extension are unknown.[23]

Figure 7. Nuclear Retirements Assuming a 60-year Maximum Operating Lifetime.



Source: EPA NEEDS database, http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html.
Note: Does not include recently retired or announced retirement nuclear units.

Potential nuclear retirements at the end of 60-year operating lifetimes are more than a decade away, but given the 10-plus-year planning horizon for new nuclear power plants, many utilities and utility regulators will need to make decisions about whether to add nuclear capacity within the next 3 to 10 years (Figure 7).[24] If nuclear generation is replaced with natural gas generation, the electricity industry's exposure to natural gas price fluctuations will increase.

Some nuclear units may not operate for their full license lifetimes. In 2013, Dominion Resources and Exelon announced, respectively, the early retirement of the Kewaunee Power Station in Wisconsin and the Vermont Yankee Power Station in Vermont. Exelon has indicated that additional merchant units in its nuclear fleet may not survive 2014.[25] Existing nuclear units in many regions are earning reduced revenues due to low wholesale power prices, largely as a result of low natural gas prices.[26] Marginal electricity prices are typically set by natural gas generation. When natural gas prices fall, the cost of the marginal generator tends to fall as well, reducing revenues for all generators within the same market.[27] If additional

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[23] Memorandum from Mark A. Satorius to the Commissions of the Nuclear Regulatory Commission (Jan. 31, 2014), *available at* http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2014/2014-0016scy.pdf.

[24] Duke Energy, THE DUKE ENERGY CAROLINAS INTEGRATED RESOURCE PLAN (ANNUAL REPORT) (Sept. 1, 2012). Duke Energy Carolinas assumes a 12 year lead-time for new nuclear units in its 2012 IRP. *Id.*

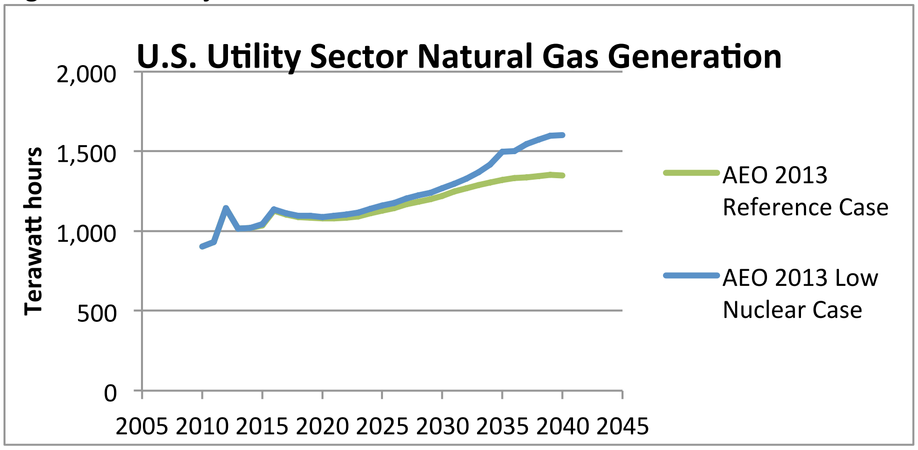
[25] Thomas Overton, *Exelon May Shutter Some Reactors in 2014*, POWER, Feb. 7, 2014, http://www.powermag.com/exelon-may-shutter-some-reactors-in-2014/.

[26] Barrón, Bipartisan Policy Center: GHG Regulation of Existing Power Plants, *supra* note 3; Dan Eggers, *et al.*, CREDIT SUISSE: NUCLEAR … THE MIDDLE AGE DILLEMMA? (Feb. 19, 2013), *available at* http://www.wecc.biz/committees/BOD/TEPPC/SPSG/Lists/Events/Attachments/485/Credit%20Suisse%20Nuclear%2019Feb13.pdf.

[27] For additional information on the challenges facing existing nuclear units, see Mark Cooper, RENAISSANCE IN REVERSE: COMPETITION PUSHES AGING U.S. NUCLEAR REACTORS TO THE BRINK OF ECONOMIC ABANDONMENT (July 18, 2013), http://216.30.191.148/071713%20VLS%20Cooper%20at%20risk%20reactor%20report%20FINAL1.pdf.

nuclear units retire due to low market prices for electricity—prices at least partially reflecting low natural gas prices—the electricity sector would likely become more dependent on natural gas generation (Figure 8). Five nuclear units are under construction, but no additional nuclear units have begun construction, and the prospects for additional units in the United States are weak.[28]

Figure 8. EIA Projections of Natural Gas Generation.

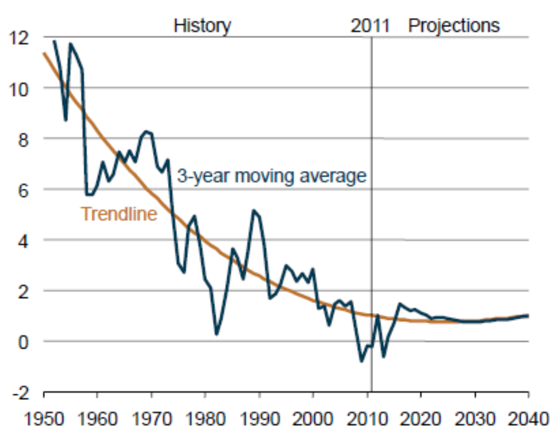


Source: Annual Energy Outlook 2013, Energy Information Administration, April 2013.
Note: The Reference Case assumes all existing nuclear units can receive extensions to continue operating past 60 years. The Low Nuclear Case assumes no existing nuclear units can operate past 60 years.

Demand Growth Uncertainty and the Risk of Stranded Assets

Another significant challenge facing the electric power sector is financing major capital investments during a period of flat or even negative demand growth.[29] EIA projects low future electricity demand growth (0.9% per year), relative to historical demand growth, in its Annual Energy Outlook 2013 Reference Case (Figure 9).[30]

Figure 9. Historical Electricity Demand and Future Demand Growth.



Source: Annual Energy Outlook 2013.

[28] World Nuclear Assoc., Nuclear Power in the USA, http://www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/ (updated Apr. 8, 2014).
[29] Gregory Aliff, DELOITTE CENTER FOR ENERGY SOLUTIONS, THE MATH DOES NOT LIE: FACTORING THE FUTURE OF U.S. ELECTRIC POWER INDUSTRY (2012).
[30] AEO 2013, *supra* note 8. The Reference Case does not include future increases in the stringency of either federal appliance efficiency standards or building energy conservation codes.

In traditional utility regulation, electric utilities recover costs and earn a return on capital investments through volumetric rates. Slow or even negative load growth during a time of increasing capital expenditures means that electricity rates per kWh will likely rise in traditionally regulated markets, further eroding demand.[31] Total energy demand is low due to a combination of increasing end use efficiency[32] and increasing distributed generation.[33] Industry observers forecast that rooftop solar is approaching grid parity in many areas of the United States, a trend that could further erode utility revenues.[34] Given the potential for low or even negative load growth, some new utility generation investments could be underutilized, or stranded, due to a lack of demand.

Despite tepid demand growth, the industry faces major capital expenditures to upgrade and replace aging infrastructure and to comply with environmental regulations. The estimated cost for new generation capacity from 2012 to 2020 exceeds $150 billion, and estimates for new transmission over the same period range from $100 to $120 billion.[35] The U.S. EPA estimates that compliance with the MATS rule will cost $9.4 billion per year in 2015, with costs decreasing over time.[36] Combined with stagnant electricity sales, these and other costs will put upward pressure on electricity rates. Increases in fuel prices would put further pressure on electricity rates, eroding demand and making distributed generation more attractive to consumers.

Policy Uncertainty

Recent experience with the new rules limiting mercury and other hazardous air pollutants, SO_2, NOx, and particulate matter—rules that took years or even decades to develop—highlight the importance of anticipating environmental regulations. The rulemaking process under way to limit CO_2 emissions from existing power plants is one of many environmental regulations that could affect the electricity sector in the near future. The EPA has proposed rules for coal combustion residuals (CCR), also known as coal ash, and cooling water for thermal power plants (316(b)).[37] In addition, it is in the process of reviewing the eight-hour ambient air quality standard for ozone.[38] The agency published a proposed rule tightening the standard in 2010 but withdrew it at the instruction of the White House.[39] On April 29, 2014, the U.S. Supreme Court removed a degree of uncertainty facing the electricity sector when it reinstated the Cross State Air Pollution Rule (CSAPR)—a rule aimed at limiting downwind transport of SO_2, NOx, and particulate matter emissions.[40] In addition to these regulatory actions, the Clean Air Act requires the EPA

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[31] In restructured electricity markets, electricity prices are set by the marginal generation cost, which may or may not cover capital costs and return on capital for investors. Low or negative demand growth in these markets would likely cause prices to drop because lower-cost generation would become the margin generation resource and, in turn, could cause bankruptcies and other financial hardship for market participants.

[32] Aliff. *supra* note 31.

[33] Kind, *supra* note 4; Larry Sherwood, INTERSTATE RENEWABLE ENERGY COUNCIL, U.S. SOLAR MARKET TRENDS 2012 (July 2013).

[34] CITI EQUITIES RESEARCH, RISING SUN: IMPLICATIONS FOR US UTILITIES (Aug. 8, 2013); Peter Fairley, *Residential Solar Power Heads Towards Grid Parity*, IEEE SPECTRUM, Mar. 28, 2013, http://spectrum.ieee.org/green-tech/solar/residential-solar-power-heads-toward-grid-parity.

[35] Aliff, *supra* note 31 (the $150 billion estimate is based on EIA projections of new capacity, overnight capital costs, and lead time for projected capacity additions); and Johannes P. Pfeifenberger & Delphine Hou, THE BRATTLE GROUP, EMPLOYMENT AND ECONOMIC BENEFITS OF TRANSMISSION INFRASTRUCTURE INVESTMENT IN THE U.S. AND CANADA (May 2011).

[36] U.S. EPA, REGULATORY IMPACT ANALYSIS FOR THE FINAL MERCURY AND AIR TOXICS STANDARD, EPA-452/R-11-011 (Dec. 2011), *available at* http://www.epa.gov/ttn/ecas/regdata/RIAs/matsriafinal.pdf.

[37] National Pollutant Discharge Elimination System--Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 76 Fed. Reg. 43230 (July 20, 2011); and Hazardous and Solid Waste Management System: Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35128 (June 21, 2010).

[38] U.S. EPA, Ground-Level Ozone: Regulatory Actions, http://www.epa.gov/groundlevelozone/actions.html (visited May 1, 2014).

[39] National Ambient Air Quality Standards for Ozone, 75 Fed. Reg. 2938 (Jan. 19, 2010). WhiteHouse.gov, Statement by the President on the Ozone National Ambient Air Quality Standards, Press Release (Sept. 2, 2011), http://www.whitehouse.gov/the-press-office/2011/09/02/statement-president-ozone-national-ambient-air-quality-standards.

[40] U.S. EPA v. EME Homer City Generation, No. 12-1182, slip op at 2 (U.S. Apr. 29, 2014).

to review ambient air quality standards every five years and NSPSs every eight years and to revise the regulations if necessary to protect public health and welfare.[41] The proposed CCR rule, the cooling water rule, increased NAAQS stringency, and increased stringency under CSAPR could all lead to additional plant retirements, depending on the stringency and form of the final rules and the market conditions.

Strategies for Addressing Current Market Challenges

Electric utilities and utility regulators can adopt multiple strategies to position themselves to deal with the above-noted challenges and risks. Despite the potential for unanticipated changes in market conditions, several planning options can help identify prudent investment decisions. For example, thorough assessments of future demand growth and future deployment of distributed generation, including impacts on energy and capacity requirements, should help to clarify future needs. Additionally, utilities and utility regulators can expand planning beyond typical least-cost scenario assessment methods. The Northwest Power and Conservation Council uses risk and cost metrics in its planning process to assess different demand-side and supply-side capacity additions over a wide range of potential futures.[42] The Tennessee Valley Authority uses an in-depth, iterative "no regrets" planning framework to ensure investments are robust, regardless of future circumstances.[43] Information about planning under significant uncertainty can be found in *Assessing the Risk of Utility Investments in a Least-Cost Planning Framework*.[44]

Electricity Sector Risk Mitigation Strategies

- Forestall or reduce need for additional capacity through use of demand-side resources and smart grid/dynamic pricing
- Increase diversity in the generation mix
  - New nuclear plants
  - Increase dispatch at existing coal-fired power plants
  - Renewable energy
  - Energy efficiency
- Use financial contracts to hedge against price volatility
- Undertake long-term power purchase agreements

In some situations, utilities may be able to forestall major capital investments, effectively delaying large-scale expenditures that could potentially limit options to react to new information regarding market demand, fuel prices, and regulatory requirements. By forestalling major investments, utilities conserve capital for other needs and avoid underutilized or stranded investments if markets experience a significant shift, as many analysts have cautioned may occur.[45]

The Duke Energy Carolinas (DEC) 2013 Integrated Resource Plan (IRP) illustrates the potential for utilities to delay major capital investments. In addition to its Base Case scenario, the DEC 2013 IRP includes an Environmental Focus scenario reflecting increases in demand-side energy efficiency and incremental increases in renewable generation. Both the Base Case and Environmental Focus scenarios include a natural gas capacity addition in 2017, but the Base Case scenario adds additional natural gas capacity in 2019, whereas the Environmental Focus scenario delays this addition until 2022. Assuming a four-year lead time, DEC and the North Carolina and South Carolina utility regulators must make a

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[41] 42 U.S.C. § 7409(d)(1) (2012) (five-year review of NAAQS); 42 U.S.C. § 7411(b)(1)(B) (2012) (eight-year review of NSPSs).
[42] NORTHWEST POWER AND CONSERVATION COUNCIL, SIXTH NORTHWEST ELECTRIC POWER AND CONSERVATION PLAN, Council Doc. 2010-09 (Feb. 2010).
[43] TENNESSEE VALLEY AUTHORITY, INTEGRATED RESOURCE PLAN TVA'S ENVIRONMENTAL AND ENERGY FUTURE (Mar. 2011).
[44] David Hoppock, *et al.*, NICHOLAS INSTITUTE FOR ENVIRONMENTAL POLICY SOLUTIONS AT DUKE UNIVERSITY, ASSESSING THE RISK OF UTILITY INVESTMENTS IN A LEAST-COST PLANNING FRAMEWORK, NI WP 13-07 (NOV. 2013), http://nicholasinstitute.duke.edu/climate/publications/assessing-risk-utility-investments-least-cost-planning-framework#.Ux9u7T9dVJQ.
[45] Kind, *supra* note 4; Aliff, *supra* note 31.

determination on the additional natural gas capacity in 2015 under the Base Case scenario, but they can delay that determination until 2018 under the Environmental Focus scenario.[46]

Demand-response and dynamic pricing options, facilitated by smart grid applications, can also forestall capacity additions. Southern Company achieves more than 3,900 MW of peak demand reduction through programs such as Energy Select, which couples programmable thermostats with an optional four-tier dynamic pricing program.[47]

Multiple options also exist to hedge against natural gas price risk. Traditionally, utilities have maintained a diverse generation portfolio, allowing them to adjust utilization rates on the basis of relative fuel prices. But they can use numerous financial, contractual, and even physical options to hedge or lock in future natural gas prices. For example, they can sign long-term contracts for gas supply or storage, buy or sell futures contracts through NYMEX, or purchase forward contracts, swaps, call options, and collars. These options, other than physical storage, tend to have durations on the order of years. NYMEX futures contracts are available up to 10 years, but their trading volume beyond 36 months is low. Long-term supply contracts are generally up to 1 year and are indexed to monthly prices.[48] Examples of longer contracts include a 10-year escalating fixed price contract between Anadarko and Public Service Company of Colorado.[49] Reducing demand through demand-side efficiency improvements and distributed generation can also reduce natural gas dependency and price risk if used as substitutes for new or existing natural gas generation.[50] Another option to reduce fuel price risk is to sign long-term power purchase agreement contracts. Wind power is typically offered through 20-year (or longer) fixed contracts with constant rates or rates that increase at approximately the rate of inflation. In addition, recent average wind power purchase agreement costs, in the mid-$40/MWh range, are cost competitive with fuel costs for natural gas units beginning in 2022, according to AEO 2013 Reference Case natural gas price projections.[51]

Options to hedge against potential nuclear retirements are more limited. If utilities and utility commissions are concerned about natural gas dependence and have nuclear units nearing the end of their second operating license, they should consider securing—in the near term—a diverse portfolio, including demand-side resources. These resources can reduce the potential for a default to gas in the event the nuclear units are retired.

The shift away from coal toward other generating resources generally facilitates management of other regulatory requirements, such as the cooling water rule and the coal combustion residuals (CCR) rule. CCRs are only produced by coal plants, and newer-generation technology tends to utilize recirculating cooling systems that withdraw much less water than older, once-through cooling, thermal plants.[52] The

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[46] Duke Energy, THE DUKE ENERGY CAROLINAS INTEGRATED RESOURCE PLAN (ANNUAL REPORT) (Oct. 15, 2013). DEC has already requested proposals for the 2017 natural gas capacity addition.
[47] Jeff Burleson, SOUTHERN COMPANY, REDUCING PEAK DEMAND (presentation at the Nat'l Assoc. of Regulatory Utility Commissioners Winter Meetings, Feb. 10, 2014), http://www.narucmeetings.org/Presentations/Tuesday%201030am%20BURLESON.pdf.
[48] Frank C Graves & Steven H. Levine, BRATTLE GROUP, MANAGING NATURAL GAS PRICE VOLATILITY: PRINCIPLES AND PRACTICES ACROSS THE INDUSTRY (Nov 2010), http://www.cleanskies.org/wp-content/uploads/2011/08/ManagingNGPriceVolatility.pdf.
[49] Bollinger, *supra* note 15.
[50] Demand-side efficiency reduces energy generation by the marginally producing unit. As noted above, natural gas is typically the marginal generator, indicating that demand-side efficiency will often displace natural gas generation.
[51] Bollinger, *supra* note 15.
[52] Union of Concerned Scientists, How It Works: Water for Power Plant Cooling, http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-cooling-power-plant.html (last visited Mar. 18, 2014).

shift from coal to other generation resources also reduces emissions of conventional pollutants (e.g., SO_2 and NO_x) and will ease compliance with the CSAPR or CAIR as well as improve ambient air quality.[53]

FORTHCOMING CO_2 LIMITS FOR EXISTING POWER PLANTS

Section 111(d) Overview

In January 2014, the EPA published a proposed rule to set new source performance standards (NSPSs) for coal-fired and natural gas-fired power plants that will limit CO_2 emissions from new facilities.[54] The vast majority of rules issued under section 111 of the Clean Air Act apply only to new sources or existing sources undergoing major modifications.[55] In this case, because the regulated pollutant (CO_2) is neither regulated as a criteria pollutant under the National Ambient Air Quality Standards program nor as a hazardous air pollutant under section 112 of the Clean Air Act, the final NSPSs for CO_2 emissions from new fossil fuel-fired power plants will trigger a requirement that states develop performance standards for *existing* power plants, subject to the EPA's guidance and approval.[56] As a result, rather than the NSPS for CO_2 emissions affecting a relatively small number of new power plants, the vast majority of the existing fossil fuel-fired units may be subject to new standards.

The EPA and states each play important roles in developing performance standards for existing sources. Under section 111(d), the EPA specifies a procedure for states to submit these standards for agency approval, a step requiring the EPA to provide official guidance that clarifies the states' obligations and the criteria by which the EPA will evaluate state plans.[57] In this guidance, the EPA will identify the "best system of emission reduction" for reducing CO_2 emissions from existing power plants and the emissions reductions achievable using that system.[58] Each state then submits a plan to the EPA that establishes performance standards for existing sources.[59] Like all performance standards under section 111 of the act, these standards must

> reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[60]

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[53] U.S. EIA, UPDATED CAPITAL COST ESTIMATES FOR UTILITY SCALE ELECTRICITY GENERATING PLANTS (Apr. 2013), http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf; and AEO 2014 EARLY RELEASE, *supra* note 9.

[54] Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (Jan. 8, 2014).

[55] The proposed NSPS does not apply to major modifications. *See id.* at 1433 President Obama has instructed the EPA to propose standards for modified and reconstructed power plants by June 1, 2014. Memorandum from President Barak Obama to the EPA, *Presidential Memorandum – Power Sector Carbon Pollution Standards* (June 25, 2013), http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[56] Some observers have questioned the EPA's authority under section 111(d) due to different versions adopted by the U.S. House of Representatives and the U.S. Senate that were not resolved in the final law. *See*, *e.g.*, William J. Haun, THE FEDERALIST SOCIETY, THE CLEAN AIR ACT AS AN OBSTACLE TO THE ENVIRONMENTAL PROTECTION AGENCY'S ANTICIPATED ATTEMPT TO REGULATE GREENHOUSE GAS EMISSIONS FROM EXISTING POWER PLANTS, at 9-12 (Mar. 2013), http://www.fed-soc.org/publications/detail/the-clean-air-act-as-an-obstacle-to-the-environmental-protection-agencys-anticipated-attempt-to-regulate-greenhouse-gas-emissions-from-existing-power-plants; Ann Brewster Weeks, *Essay Responding to Brian H. Potts*, 31 YALE J. ON REG. ONLINE 38 (posted Oct. 20, 2013), http://jreg.commons.yale.edu/essay-responding-to-brian-h-potts/ (arguing that the EPA is authorized to regulate power plants under section 111(d)). The EPA responded to this issue in the Clean Air Mercury Rule, issued in 2005, *see* Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, 70 Fed. Reg. 15,994, 16,030-32 (Mar. 29, 2005), vacated on other grounds, *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[57] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.22.

[58] 40 Fed. Reg. 55,340, 53,342-44 (Nov. 17, 1975); 42 U.S.C. § 7411(a)&(d).

[59] 42 U.S.C. § 7411(d)(1).

[60] 42 U.S.C. § 7411(a)(1).

The Clean Air Act does not define the term "best system," and it grants states the authority to identify standards that "reflect the degree of *emission limitation achievable* through application of the best system of emission reduction," as opposed to implementing a single "best system." These two factors lead many scholars and stakeholders to conclude that the statute (1) does not limit regulators to actions that occur at each specific unit and (2) could allow performance standards for existing power plants to include a broad range of options that result in emissions reductions from the electricity system.[61] The EPA has previously determined that emissions averaging across facilities or emissions trading can qualify as a "best system."[62] The Clean Air Act grants discretion to the states to define the options for covered entities within their borders to secure the required emissions reductions. Those options might include heat rate improvements at a facility, shifts in dispatch, investments in end-user energy efficiency to reduce demand, or construction of new generation that emits fewer CO_2 emissions. The range of available options will affect electricity generators' compliance strategies and potential to use those strategies to address other electricity sector challenges.

Potential 111(d) Compliance Strategies

Unit-level options for reducing CO_2 emissions from the existing fleet of coal-fired power plants include a host of efficiency upgrade options, fuel switching, co-firing with lower-carbon fuels, and reducing dispatch.[63] Since 2012, state officials and other stakeholders have released a range of proposals that would allow emissions averaging, emissions trading (intrastate and regional), and credit for investments in energy efficiency, renewables, and nuclear energy. Another proposal is to measure total CO_2 emissions from covered units within a state and to allow that state to choose how best to achieve the required emissions reductions.[64]

Potential Compliance Strategies for Section 111(d)

- Increased generation from zero- or lower-emitting sources such as renewable or nuclear energy
- Co-firing with lower-carbon fuels
- Unit-level efficiency improvements
- End-use energy efficiency
- Emissions averaging/trading
- Retirement of facilities emitting CO_2

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[61] *See, e.g.,* Kate Konschnik & Ari Peskoe, Harvard Law School Environmental Law Program, Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants (Mar. 3, 2014); Monast, *et al.*, *Regulating Greenhouse Gas Emissions from Existing Sources: Section 111(d) and State Equivalency*, 42 ENVTL. L. REP. 10206 (Mar. 2012); Gregory E. Wannier, RESOURCES FOR THE FUTURE DISCUSSION PAPER, PREVAILING ACADEMIC VIEW ON COMPLIANCE FLEXIBILITY UNDER § 111 OF THE CLEAN AIR ACT, RFF DP 11-29 (July 2011).

[62] *See* Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units (Clean Air Mercury Rule), 70 Fed. Reg. 28,606 (July 18, 2005).

[63] *See, e.g.,* Richard J. Campbell, CONG. RES. SERVICE, INCREASING THE EFFICIENCY OF EXISTING COAL- FIRED POWER PLANTS, R43343 (Dec. 20, 2013); Mass. Inst. of Tech. Energy Initiative Symposium, Retrofitting of Coal-Fired Power Plants for CO2 Emissions Reductions, at 19 (Mar. 23, 2009), http://mitei.mit.edu/system/files/meeting-report.pdf; Chris Nichols, *et al.*, U.S. NAT'L ENERGY TECH. LAB., REDUCING CO2 EMISSIONS BY IMPROVING THE EFFICIENCY OF THE EXISTING COAL-FIRED POWER PLANT FLEET, DOE/NETL-2008/1329 (July 2008), http://www.netl.doe.gov/energy-analyses/ pubs/CFPP%20Efficiency-FINAL.pdf.

[64] *See, e.g.*, ISO/RTO Council, EPA CO_2 Rule—ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals, at 4-7 (Jan. 28, 2014), http://www.isorto.org/ircreportsandfilings/irc-reliability-safety-valve-and-regional-compliance-measurement-proposal-in-response-to-epa-c02-rul; Letter from Mary D. Nichols, Chair, Cal. Air Resources Board, *et al.*, to Gina McCarthy, EPA Administrator (Dec. 16, 2013), *available at* http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf (attaching STATES' §111(D) IMPLEMENTATION GROUP INPUT TO EPA ON CARBON POLLUTION STANDARDS FOR EXISTING POWER PLANTS); Letter from Daniel C. Esty, Commissioner, Conn. Dept. of Energy and Envtl. Protection, *et al.*, to Gina McCarthy, EPA Administrator (Dec. 2, 2013), *available at* rggi.org/docs/RGGI_States_111d_Letter_Comments.pdf (attaching REPORT ON EMISSION REDUCTION EFFORTS OF THE STATES PARTICIPATING IN THE REGIONAL GREENHOUSE GAS INITIATIVE AND RECOMMENDATIONS FOR GUIDELINES UNDER SECTION 111(D) OF THE CLEAN AIR ACT); Letter from Leonard K. Peters, Secretary, Ky. Energy and Environment Cabinet to Gina McCarthy, EPA Administrator (Oct. 22, 2013), *available at* http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf (attaching GREENHOUSE GAS POLICY IMPLICATIONS FOR KENTUCKY UNDER SECTION 111(D) OF THE CLEAN AIR ACT); Daniel A. Lashof, *et al.*, NRDC,

There is notable disagreement about the EPA's authority to set stringent emissions limits or to consider emissions reductions not resulting from sources subject to the 111(d) rule (e.g., investments in renewable energy generation) when identifying emissions limits for existing sources.[65] Nonetheless, stakeholders across the political spectrum interpret the Clean Air Act to grant broad discretion to the states in designing performance standards.[66] Numerous states have one or more strategies in place to limit CO_2 emissions, including renewable portfolio standards, end-use energy efficiency programs,[67] and statewide[68] and regional greenhouse gas emissions markets.[69] Each of these strategies offers the potential for achieving cost-effective CO_2 emission reductions from the power sector. But because these strategies have not yet been attempted under section 111(d), their role in compliance with performance standard obligations is unclear. Many states are also seeing reductions in CO_2 emissions as electric generators retire coal-fired power plants and replace them with natural gas facilities.

A MULTI-BENEFITS FRAMEWORK: ADDRESSING ELECTRICITY SECTOR CHALLENGES AND COMPLYING WITH SECTION 111(D) REQUIREMENTS

There is notable overlap between the strategies for mitigating electricity sector risks and potential compliance strategies for the section 111(d) rulemaking process. This overlap presents regulators with an opportunity to pursue strategies that address forthcoming challenges and achieve CO_2 reductions required under state section 111(d) plans.

CLOSING THE POWER PLANT CARBON POLLUTION LOOPHOLE: SMART WAYS THE CLEAN AIR ACT CAN CLEAN UP AMERICA'S BIGGEST CLIMATE POLLUTERS (Mar. 2013), http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

[65] *Compare* Megan Ceronsky & Tomás Carbonell, ENVIRONMENTAL DEFENSE FUND, § 111(D) OF THE CLEAN AIR ACT: THE LEGAL FOUNDATION FOR STRONG, FLEXIBLE & COST-EFFECTIVE CARBON POLLUTION STANDARDS FOR EXISTING POWER PLANTS (Oct. 2013, revised Feb. 2014), http://edf.org/content/111d-clean-air-act *and* Lashof, *et al.*, *supra* note 66 *with* N.C. DEPT. OF ENVIRONMENT & NATURAL RESOURCES, NORTH CAROLINA §111(D) PRINCIPLES, Jan. 27, 2014), daq.state.nc.us/rules/EGUs/NC_111d_Principles.pdf *and* HUNTON & WILLIAMS, ESTABLISHMENT OF STANDARDS OF PERFORMANCE FOR CARBON DIOXIDE EMISSIONS FROM EXISTING ELECTRIC UTILITY GENERATING UNITS UNDER CLEAN AIR ACT § 111(D) (Apr. 2013), *available at* http://www.publicpower.org/files/PDFs/NSPS111%28d%29Analysis.pdf.

[66] *Id.*

[67] For a compilation of state energy efficiency and renewable energy policies, see The Database of State Incentives for Renewables & Efficiency, dsireusa.org.

[68] *See* California Air Resources Board, Cap-and-Trade Program, http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm (last updated Mar. 14, 2014).

[69] *See* Regional Greenhouse Gas Initiative, rggi.org.

Table 3. Overlap of Electricity Sector Risk Reduction Strategies and Section 111(d) Compliance Options.

Utility Regulators ***Strategies to Address Electricity Sector Challenges***	**Environmental Regulators** ***Section 111(d) Compliance Options***
Forestall or reduce need for additional capacity	**Reduce dispatch of higher-carbon fossil generation**
Use demand-side resources, including end-use efficiency, and smart grid/dynamic pricing	Incentivize end-use energy efficiency
Diversity in the generation mix	**Increase lower-carbon energy resources**
Renewable energy Co-firing w/ lower carbon fuels New nuclear generation Emerging technologies for electricity generation and pollution control	Renewable energy Co-firing w/ lower carbon fuels New nuclear generation Emerging technologies for electricity generation and pollution control
Increased dispatch of existing coal-fired power plants	
Financial contracts to hedge against price volatility	**Unit-level efficiency improvements**

Electricity sector challenges and the potential for CO_2 emissions reductions from strategies to meet those challenges vary significantly by state. Discussed below are three strategies that could play a role in risk mitigation and potentially satisfy forthcoming CO_2 performance standards for existing power plants. Deciding on a particular strategy or strategies will require a detailed assessment of the state's energy sector and greater certainty regarding the EPA and states' choices regarding section 111(d) policy design.

Reducing Electricity Demand through End-Use Energy Efficiency

End-use energy efficiency—gaining the same service with less overall electricity consumption—is generally recognized as a low-cost option for reducing CO_2 emissions and is included in many white papers outlining section 111(d) compliance strategies. The level of emissions reduction resulting from efficiency investments depends on the amount of avoided generation from fossil fuel-fired power plants and on whether the reduced demand affected natural gas-fired or coal-fired facilities.[70] The specificity required under section 111(d) plans regarding the link between end-use energy efficiency measures and reduced emissions at covered units subject to performance standard requirements may affect whether states view energy efficiency as a feasible compliance option.

Potential benefits

- Reducing CO_2 emissions
- Hedging demand growth uncertainty
- Hedging environmental policy uncertainty
- Hedging fuel price volatility

Beyond reductions in CO_2 emissions and emissions of other pollutants produced by fossil fuel combustion, energy efficiency programs can provide energy savings for consumers.[71] Less appreciated is the potential for energy efficiency investments to help utilities hedge against price volatility and uncertain demand growth. In areas with projected demand growth, energy efficiency can forestall or eliminate requirements for additional capacity. In today's low natural gas price environment, much of this capacity is likely to come from natural gas-fueled generation. Reducing future demand growth through end-use efficiency, therefore, may reduce dependence on natural gas and associated price volatility risk. Additionally, by forestalling capacity additions, end-use efficiency hedges against underutilized capacity in the event future demand growth does not materialize due to factors such as increases in distributed generation or end-use efficiency improvements. By forestalling major capital investments, energy efficiency conserves capital and facilitates flexibility by allowing otherwise sunk capital to be invested in response to changing markets and technological advances.

Increasing Renewable Energy Generation

Once constructed, renewable energy resources such as wind and solar produce electricity without fuel costs and without directly emitting CO_2 and other regulated pollutants.[72]

Potential benefits

- Reducing CO_2 emissions
- Hedging environmental policy uncertainty
- Hedging fuel price volatility

Wind and solar have both experienced significant growth over the past decade—more than 1,000% and 1,500% generation growth, respectively, due to a combination of tax credits, state renewable portfolio standards, technology improvements, and improving market conditions.[73] As noted above, wind is already cost competitive in some markets, and the falling price of photovoltaic panels is leading to increases in both rooftop and utility-scale solar installations.[74]

Renewable energy can help hedge against natural gas price fluctuations by reducing natural gas generation, the potential for more stringent CO_2 limits, and the potential for

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[70] Jeremy M. Tarr, *et al.*, NICHOLAS INSTITUTE FOR ENVIRONMENTAL POLICY SOLUTIONS AT DUKE UNIVERSITY, ENERGY EFFICIENCY AND GREENHOUSE GAS LIMITS FOR EXISTING POWER PLANTS: LEARNING FROM EPA PRECEDENT (June 2013), http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-04_0.pdf.

[71] For example, the Electric Cooperatives of South Carolina report that a pilot on-bill efficiency-financing program resulted in the average annual savings of $1,157; consumers' annual net savings equaled $288 after loan repayment. Loans averaged $7,700 and financed measures such as air sealing, duct leakage reduction, attic insulation, and replacement of electric furnaces with heat pumps. Consumers participating in the pilot program are projected to save more than $8,500 over a 15-year period. http://www.cepci.org/assets/HelpMyHouseBrochure_June2013.pdf.

[72] Hydropower also produces electricity without fuel costs. Hydropower was not included in this paper because of low projected growth, according to the AEO 2014 Early Release, *surpa* note 10.

[73] EIA, Electric Power Monthly, February 2014.

[74] Bollinger, *supra* note 15; Larry Sherwood, U.S. Solar Market Trends 2012, Interstate Renewable Energy Council, July 2013.

increasingly stringent limits on criteria pollutants.[75] However, the net environmental benefits and hedging value of renewable energy resources depends on the amount of cycling of fossil generation necessary to address intermittency.[76]

Additional Options for Expanding Generation from Low-Carbon Energy Sources

Other options for reducing CO_2 emissions, hedging environmental policy uncertainty by reducing emissions of other regulated pollutants, and hedging concerns about natural gas price volatility include biomass generation (through dedicated biomass generation facilities or by co-firing biomass with coal) and new nuclear generation.[77] Demand response—reducing electricity demand during periods of peak demand—is currently treated as a capacity resource in competitive wholesale markets and may also achieve these goals, depending on the type of generation avoided.[78] Its CO_2 emissions benefits may be less significant than its price, diversity, and system reliability benefits.

New nuclear generation will likely be difficult to justify solely on a cost basis. Table 1 shows that the levelized cost of a new nuclear plant is an estimated 62% higher than a natural gas combined cycle facility due to the high capital costs associated with nuclear plant construction. Although nuclear facilities are under construction in Georgia and South Carolina, getting approval from public utility commissions for other such facilities in this period of demand growth uncertainty may be difficult.[79] However, concerns about increasingly stringent CO_2 emissions limits and a desire to maintain fuel diversity could cause utility regulators and investors to view nuclear more favorably.

Potential benefits

- Reducing CO_2 emissions
- Hedging environmental policy uncertainty
- Hedging fuel price volatility

Similar concerns could also cause utilities and utility regulators to consider pursuit of carbon capture demonstration and early deployment projects under the right circumstances. Carbon capture projects have thus far met with mixed success in public utility commission proceedings. For example, the Mississippi and West Virginia public service commissions (PSCs) have recognized that coal-fired power plants with carbon capture can provide value for the state's respective electricity sectors and economies, in part by hedging the potential for future CO_2 emission limits.[80] The Mississippi PSC ultimately approved the proposal by Mississippi Power to construct a coal-fired integrated gasification combined cycle (IGCC) facility that will capture approximately 65% of the plant's

[75] For a discussion of the history of more stringent environmental regulations over time, see Jonas J. Monast & Sarah K. Adair, *A Triple Bottom Line for Electric Utility Regulation: Aligning State-Level Energy, Environmental, and Consumer Protection Goals*, 38 COLUMBIA J. OF ENVTL. L. 1, at 21–36 (2013).

[76] Cycling fossil generation (natural gas and coal) to integrate these intermittent resources can result in increased CO_2 and NOx emissions rates for fossil units. Warren Katzenstein & Jay Apt, *Air Emissions Due to Wind and Solar Power*, 43 ENVIRON. SCI. TECH. 253 (2009); D. Lew, *et al*., U.S. NAT'L ENERGY TECH. LAB., THE WESTERN WIND AND SOLAR INTEGRATION STUDY PHASE 2, NREL/TP-5500-55588 (Sept. 2013).

[77] The EPA has yet to issue guidance on calculating greenhouse gas emissions from bioenergy. In June 2011, the agency issued a three-year deferral for biomass facilities complying with the Tailoring Rule, claiming that more time was needed to assess total emissions. Final Deferral for CO_2 emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration (PSD) and Title V, 76 Fed. Reg. 43490 (July 20, 2011). The D.C. Circuit vacated the deferral in 2013. *Coalition for Responsible Regulation, Inc. v. EPA*, 722 F.3d 401 (D.C. Cir. 2013).

[78] PJM, DEMAND RESPONSE, http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/demand-response-fact-sheet.ashx.

[79] Department of Energy Office of Nuclear Energy, *Quarterly Nuclear Deployment Scorecard* (Jan. 2014), http://www.energy.gov/ne/downloads/quarterly-nuclear-deployment-scorecard-january-2014.

[80] *Appalachian Power Co. and Wheeling Power Co. both dba American Electric Power Commission Order on the Application for a Rate Increase,* Order on the Application for a Rate Increase, Case No. 10-0699-E-42T, W.V. P.S.C., March 30, 2011, at 47 (hereinafter W.V. CCS Order); *In re: Petition of Mississippi Power Co. for a Certificate of Public Convenience and Necessity Authorizing the Acquisition, Construction, and Operation of an Electric Generating Plant, Associated Transmission Facilities, Associated Gas Pipeline Facilities, Associated Rights-of-Way, and Related Facilities in Kemper, Lauderdale, Clarke, and Jasper Counties, Mississippi,* Final Order on Remand, Docket No. 2009-UA-014, Miss. P.S.C., April 24, 2012 (hereinafter Ms. IGCC Order).

carbon emissions and sell the CO_2 for enhanced oil recovery.[81] The West Virginia PSC approved partial cost recovery for a carbon capture and storage demonstration project proposed by Appalachian Power Company, a subsidiary of American Electric Power with a service territory that covers parts of West Virginia and Virginia, but the project did not proceed after the Virginia State Commerce Committee rejected the proposal.[82] The cost of full-scale carbon capture and storage projects at coal-fired power plants is estimated to be approximately 20% higher than the cost of a new nuclear facility and twice the cost of a natural gas combined cycle plant (Table 1). Cost overruns at Mississippi Power's Kemper County plant may raise further concerns about the viability of a coal-fired power plant with carbon capture technologies. Nonetheless, the combination of the proposed NSPS rule requiring any new coal-fired power plant to capture approximately 40% of its CO_2 emissions and the 111(d) rule targeting CO_2 emissions from existing coal-fired power plants could cause some states to approve carbon capture projects in an effort to preserve a role for coal in the U.S. energy mix, especially if significant levels of federal funding became available or if the cost of the technology drops to a level that is more competitive with conventional options.

CONCLUSION

Coal facility retirements, low natural gas prices, low electricity demand, and new air quality regulations, combined with the prospect of large amounts of nuclear generation retiring within the next 20 years, are triggering a significant transition within the electricity sector. Responses to these challenges will have a direct impact on the related public policy goals of maintaining an affordable and reliable electricity sector while also protecting public health and reducing CO_2 emissions. The flexibility embedded in section 111(d) of the Clean Air Act, and the fact that the 111(d) rulemaking process to limit CO_2 emissions from existing power plants coincides with the emergence of these challenges, presents state regulators with an opportunity to pursue strategies that simultaneously limit CO_2 emissions and address other electricity sector needs. Identifying and implementing multi-benefit approaches for any given state will likely require an increased level of coordination among utility commissioners and environmental regulators. Although each group has important expertise to contribute, the regulatory structure in many states does not encourage—and may even discourage—interaction among these experts.

[81] Ms. IGCC Order, *supra* note 82.

[82] W.V. CCS Order, *supra* note 79; *Application of Appalachian Power Company for a statutory review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to §56-585.1 A of the Code of Virginia,* Final Order, Case No. PUE-2009-0030, July 15, 2009.

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