

Designing CO₂ Performance Standards for a Transitioning Electricity Sector: A Multi-Benefits Framework

by Jonas Monast and David Hoppock

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Summary

A significant transition is underway within the electricity sector due to several market forces, retirement of certain plants, and regulatory pressures. There is notable overlap between available strategies for mitigating electricity sector risks and potential compliance strategies for states under the Clean Power Plan. This overlap presents regulators with an opportunity to pursue strategies that help manage the transition occurring in the electricity sector and achieve greenhouse gas reductions required under the Clean Power Plan, particularly in the areas of end-use energy efficiency and additional renewable power generation.

I. Introduction

The proposal by the U.S. Environmental Protection Agency (EPA) to limit carbon dioxide (CO₂) emissions from existing power plants comes at a time when the electricity sector is in the midst of a significant transition due to market, regulatory, and technological forces. 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 EPA promulgated new rules, the Mercury and Air Toxics Standards (MATS), to limit hazardous air pollutants as well as rules to limit downwind transport of sulfur dioxide (SO₂), nitrogen oxides (NO_x), 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 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 plants³—a situation that would have seemed highly unlikely only a few years ago. Together, relatively flat electricity demand and inexpensive photovoltaic panels have the potential to challenge the traditional electric utility business model by shrinking revenues from electricity sales.⁴ In addition to these economic, technical, and regulatory shifts, in January 2014,

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1. *Evaluating the Role of FERC in a Changing Energy Landscape: Hearing Before the Subcomm. on Energy and Power of the House Comm. on Energy and Commerce*, 113th Cong. (2013) (written testimony of John R. Norris, Commissioner, Fed. Energy Reg. Comm'n), 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 (MATS), 77 Fed. Reg. 9304, 9367-70 (Feb. 16, 2012) (codified at 40 C.F.R. pts. 60, 63); Cross-State Air Pollution Rule, 76 Fed. Reg. 48208, 48208 (codified at 40 C.F.R. pts. 51-52, 72, 78, 97).
3. JEFFREY JONES & MICHAEL LEFF, U.S. ENERGY INFO. ADMIN. (EIA), ISSUES IN FOCUS: IMPLICATIONS OF ACCELERATED POWER PLANT RETIREMENTS, DOE/EIA-0383 (2014), http://www.eia.gov/forecasts/aeo/section_issues.cfm#power_plant.
4. Peter Kind, Edison Elec. Inst., *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (2013).

EPA proposed new source performance standards (NSPSs) to limit CO₂ emissions from new coal-fired and natural gas-fired power plants. Following the NSPS proposal, the Agency released a proposed rule under §111(d) of the Clean Air Act (CAA)⁵ to limit CO₂ emissions from existing coal-fired and natural gas-fired facilities.

Viewed in isolation, limiting CO₂ 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 CO₂ emissions from the power sector may also address numerous other electricity sector risks. Much of this potential is rooted in the statutory language of §111(d), which could provide a range of flexible compliance options to state regulators.

This Article explores the options for addressing electricity sector concerns while simultaneously implementing strategies to reduce CO₂ 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 CAA §111(d) and the options available to the states to limit CO₂ emissions from existing fossil fuel-fired facilities. The Article concludes by outlining §111(d) compliance strategies that could help mitigate the other challenges facing the electric power sector.

II. State-Level Regulation of the Electricity Sector

State regulatory agencies overseeing the electricity sector typically have distinct mandates: Utility commissions generally focus on economic regulation of the electricity sector, whereas state environmental agencies focus on protecting public health and the environment.⁶ In some states, energy offices oversee energy efficiency and renewable energy policies.⁷ Together, these government officials will grapple with many difficult questions in the next few years, including:

- How important is maintaining diversity in the electricity sector 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 CO₂ emissions from the existing fleet of fossil fuel-fired power plants?

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. Reducing CO₂ emissions while also maintaining an affordable and reliable 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 CO₂ emissions from the electric power sector. Some, but certainly not all, choices could achieve both goals. The emergence of these issues in a relatively short time frame 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 §111(d) proposal released in June 2014 allows states to choose among a range of options available as they design performance standards for the sector.⁸ With proper planning, this regulatory flexibility may allow state officials to identify options that satisfy the broadest range of policy goals.

III. A Rapidly Changing Electricity Sector

A number of market, regulatory, and technological factors occurring in a relatively short time frame are resulting in dramatic changes throughout the electricity sector and complicating efforts to engage in long-term planning. First, a large percentage of coal-fired power plants are retir-

5. Clean Air Act (CAA), 42 U.S.C. §§7401-7671q, ELR STAT. CAA §§101-618.

6. For more detail about the roles of the state utility commissions, environmental agencies, and energy offices, 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 COLUM. J. ENVTL. L. 1, 10-19 (2013).

7. See, e.g., Maryland Energy Admin., <http://energy.maryland.gov/>.

8. See, e.g., Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34832 (June 18, 2014):

The proposal provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs. It also allows states to pursue policies to reduce carbon pollution that: (1) Continue to rely on a diverse set of energy resources, (2) ensure electric system reliability, (3) provide affordable electricity, (4) recognize investments that states and power companies are already making, and (5) can be tailored to meet the specific energy, environmental and economic needs and goals of each state.

ing in a relatively short time period.⁹ Second, the sector is increasing its reliance on natural gas generation, creating concerns about increased exposure to fuel price volatility.¹⁰ Third, future electricity demand growth is uncertain, with the potential for flat or even declining demand in the coming years.¹¹ This uncertainty comes at a time when power plant operators are facing significant capital expenditures for emissions control retrofits and new generation, and therefore complicates investment decisions. Fourth, licenses for approximately one-third of the nation's nuclear capacity will expire between 2030 and 2035. Due to the long licensing and construction time lines associated with nuclear power plants, most operators must decide whether or not to renew those licenses, replace the aging units with new facilities, or replace the units with a different generation option within the next five to 10 years. Fifth, rapid growth in demand-side resources such as distributed solar could reduce electric utilities' sales and revenues. Finally, upcoming environmental regulations and policy, the details of which are unknown, will likely affect the economics of electricity generation. The following subsections describe each of these factors in more detail.

A. Retiring Older Coal-Fired Power Plants

Forthcoming regulation of emissions from existing coal units, most notably 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.¹² Environmental retrofit costs tend to be higher per unit of capacity for smaller units (less than 300 megawatts (MW)) than for larger units.¹³ The U.S. Energy Information Administration (EIA) projects that 60 gigawatts (GW) of coal-fired capacity—19% of 2010 coal capacity—will retire by 2020.¹⁴ Approximately 90% of projected plant closures will occur by 2016, when remaining coal units must comply with the emissions limits established under MATS.¹⁵ The rapid retirement of this segment of traditional base-load capacity will cause a significant shift for the electricity sector.

Energy projections suggest that it is highly unlikely that utilities will replace the retiring generation with new coal-fired power plants. For example, in EIA's Annual Energy

Outlook 2014 Early Release, which does not reflect EPA regulations restricting electricity sector CO₂ emissions, the projection is for less than 0.5 GW of new coal capacity through 2040.¹⁶

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

I. 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.¹⁷ 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.¹⁸

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.

A comparison of EIA's levelized cost for new generation in Table 1 above with the levelized cost estimates for a low-heat-rate natural gas combined cycle (NGCC) unit shown in Table 2 below shows that natural gas prices would need to more than double current New York Mercantile Exchange (NYMEX) futures prices to make other dispatchable resources cost competitive with new combined-cycle generation.¹⁹

2. Risk of Increased Exposure to Price Volatility

Historically, natural gas prices have shown significant volatility relative to coal prices.²⁰ Projections of recover-

9. 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> [hereinafter U.S. EIA, *Today in Energy*].

10. SUE TIERNEY ET AL., THE ASPEN INSTITUTE, RESPONDING TO TRENDS IN THE U.S. ELECTRICITY SECTOR 14 (2014), available at <http://www.aspeninstitute.org/sites/default/files/content/docs/pubs/2014EnergyPolicyReport.pdf>.

11. U.S. EIA, ANNUAL ENERGY OUTLOOK 2014, at MT-16 (Apr. 2014), available at <http://www.eia.gov/forecasts/aeo/pdf/0383%282014%29.pdf>.

12. U.S. EIA, *Today in Energy*, *supra* note 9.

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

14. U.S. EIA, *Today in Energy*, *supra* note 9; U.S. EIA, ANNUAL ENERGY OUTLOOK 2013 (Apr. 2013) (hereinafter U.S. EIA ANNUAL OUTLOOK 2013).

15. U.S. EIA, *Today in Energy*, *supra* note 9.

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

17. U.S. EIA, ANNUAL OUTLOOK 2013, *supra* note 14.

18. Capacity additions include all natural gas combined cycle (NGCC) units and oil and gas combustion turbine units. U.S. EIA, 2014 EARLY RELEASE, *supra* note 16.

19. 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. See 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>.

20. Historical coal prices are available from EIA at <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0709>. Historical natural gas prices are

Table 1
Average Levelized Costs (2011 \$/Megawatt Hour (MWh) for Plants Entering Service in 2018^a

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed Operations & Maintenance (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 carbon capture and sequestration (CCS)	85	88.4	8.8	37.2	1.2	135.5
Natural gas combined cycle (NGCC)	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 natural gas 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 ^b	34	70.3	13.1	0	3.2	86.6
Solar photovoltaics ^{b, c}	25	130.4	9.9	0	4	144.3

a. U.S. EIA, ANNUAL ENERGY OUTLOOK 2013 EARLY RELEASE OVERVIEW: LEVELIZED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2013 (2012), http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm.

b. Does not include state and federal tax incentives.

c. Costs are expressed in terms of net alternating current power available to the grid for the installed capacity.

Table 2
Levelized Cost of New NGCC Generation Entering Service in 2018

	\$5/million metric British thermal units (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.

able 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.²¹ 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.²²

While natural gas markets may experience less volatility in the future due to expanding supply from shale resources, increased reliance on natural gas generation coupled with a return to past volatility would create significant price risk for consumers.²³ Additionally, during this period of low gas prices, it is generally assumed that

there is more upside than downside price risk.²⁴ 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 overreliance on natural gas generation.²⁵

New NGCC and combustion turbine units are generally assumed to have an operating life of 30 years, well beyond the scope of NYMEX futures markets.²⁶ If natural gas units were to operate at high use rates during periods of high natural gas prices, ratepayers would likely see cor-

available at <http://www.eia.gov/dnav/ng/hist/n9190us3m.htm>.

21. 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>. See also U.S. EIA, ANNUAL OUTLOOK 2013, *supra* note 14.

22. U.S. EIA, Henry Hub Natural Gas Spot Price, <http://www.eia.gov/dnav/ng/hist/rngwhhdw.htm>.

23. 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 (2013).

24. See, e.g., TIERNEY ET AL., *supra* note 10, at 13-16.

25. 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>; Phyllis Reha, *The Role of Natural Gas in Minnesota's Energy Future* (presentation at the Environmental Initiative Policy Conference, Concordia Univ., Sept. 21, 2012), <http://www.slideshare.net/Environmental-Initiative/policy-forum-series-reha-the-role-of-natural-gas-in-minnesotas-energy-future>. Projections of natural gas prices have consistently proven to be incorrect. See, e.g., KENTUCKY ENERGY & ENV'T CABINET, ECONOMIC CHALLENGES FACING KENTUCKY'S ELECTRICITY GENERATION UNDER GREENHOUSE GAS CONSTRAINTS, at 9, 11 (2013).

26. 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, ch. 8: Financial Assumptions, http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_8.pdf (last visited Apr. 15, 2014).

responding increases in electricity prices. More non-gas dispatch options during these periods would help alleviate the price pressure.

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. Natural gas prices in New England increased significantly in January and February 2014 as cold weather increased demand for natural gas for heating and pipeline constraints limited supply into the region.²⁷ As a result of high natural gas prices and increased demand, spot electricity prices exceeded \$600/MWh at the New England ISO [Independent System Operator] regional hub, with average prices of \$169/MWh in January 2014 and \$161/MWh from February 1-18, 2014. For comparison, prices at the same hub averaged \$45/MWh in November 2013.²⁸ But 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.²⁹ 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.³⁰

C. Demand Growth Uncertainty and the Risk of Stranded Assets

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 kilowatt hour (kWh) will likely rise in traditionally regulated markets, further eroding demand.³¹ EIA projects low future electricity demand growth (0.9% per

year), relative to historical demand growth, in its Annual Energy Outlook 2013 Reference Case.³² Total energy demand is low due to a combination of increasing end-use efficiency³³ and increasing distributed generation.³⁴ 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.³⁵ 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.³⁶ EPA estimates that compliance with the MATS rule will cost \$9.4 billion per year in 2015, with costs decreasing over time.³⁷ 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.

D. Pending Nuclear Retirements

Nuclear power provides approximately 20% of the electricity generation in the United States.³⁸ 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).³⁹ Although the Nuclear Regulatory Commission has begun the process 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.⁴⁰

Potential nuclear retirements due to expiring operating licenses are more than a decade away, but given the 10-plus-year planning horizon for new nuclear power plants, many

27. 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#>.

28. 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 Jan. 23, 2014, reached \$688/MWh. See *id.*

29. 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; U.S. EIA, 2014 EARLY RELEASE, *supra* note 16; U.S. EIA, ANNUAL OUTLOOK 2013, *supra* note 14. 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>.

30. Natural Gas Assoc., *Planned Enhancements, Northeast Natural Gas Pipeline Systems* (2014), http://www.northeastgas.org/pdf/system_enhance0314.pdf.

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. See, e.g., Gregory Aliff, Deloitte Ctr. for Energy Solutions, *The Math Does Not Lie: Factoring the Future of U.S. Electric Power Industry* (2012).

32. U.S. EIA, ANNUAL OUTLOOK 2013, *supra* note 14. The Reference Case does not include future increases in the stringency of either federal appliance efficiency standards or building energy conservation codes.

33. See Aliff, *supra* note 31.

34. Kind, *supra* note 4; Larry Sherwood, Interstate Renewable Energy Council, *U.S. Solar Market Trends 2012* (2013).

35. Citi Equities Research, *Rising Sun: Implications for U.S. Utilities* (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>.

36. See 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); see also Johannes P. Pfeifenberger & Delphine Hou, Brattle Grp., *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada* (2011).

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

38. U.S. EIA, ANNUAL OUTLOOK 2013, *supra* note 14.

39. Based on data from EPA's National Electric Energy Data System (NEEDS) v.4.10 database, available at <http://www.epa.gov/airmarkets/progsregs/epaipm/BaseCase410.html>.

40. Memorandum from Mark A. Satorius, Executive Director for Operations, to the Commissioners of the Nuclear Regulatory Commission (Jan. 31, 2014), available at <http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2014/2014-0016scyp.pdf>.

utilities and utility regulators will need to make decisions about whether to add nuclear capacity within the next three to 10 years.⁴¹ If nuclear generation is replaced with natural gas generation, the electricity industry's exposure to natural gas price fluctuations will increase and total CO₂ emissions will increase.⁴²

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 2014.⁴³ 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.⁴⁴ 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.⁴⁵ If additional 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. 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.⁴⁶

E. Policy Uncertainty

Recent experience with the new rules limiting mercury and other hazardous air pollutants, SO₂, NO_x, and particulate matter—rules that took years or even decades to develop⁴⁷—highlight the importance of anticipating environmental regulations. The rulemaking process underway to limit CO₂ emissions from existing power plants is one of

many environmental regulations that could affect the electricity sector in the near future. EPA has proposed rules for coal combustion residuals (CCR), also known as coal ash, and cooling water for thermal power plants (under Clean Water Act §316(b)).⁴⁸ In August 2014, EPA published its final policy assessment of the national ambient air quality standard (NAAQS) for ozone, finding that the current standard of 75 parts per billion is inadequate to protect public health and recommending tightening the standard to between 60–70 ppb.⁴⁹ This followed a 2010 standard-tightening proposed rule that was subsequently withdrawn at the instruction of the White House.⁵⁰ EPA is under a court order to propose a revised ozone NAAQS standard by December 2014 and to finalize the standard by October 2015.⁵¹ 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 SO₂, NO_x, and particulate matter emissions.⁵²

In addition to these regulatory actions, the CAA requires EPA to review ambient air quality standards every five years and NSPSs every eight years and revise the regulations if necessary to protect public health and welfare.⁵³ The proposed CCR rule, the cooling water rule, increased NAAQS stringency, and increased stringency under the CSAPR could all lead to additional plant retirements or changes in dispatch, depending on the stringency and form of the final rules and the market conditions.⁵⁴

F. Strategies for Addressing Current Market Challenges

Electric utilities and utility regulators can adopt multiple strategies to position themselves to deal with the challenges and risks noted above. Despite the potential for unanticipated changes in market conditions, several planning options can help identify prudent investment deci-

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

42. If the increased emissions occur due to new natural gas generation, performance standards issued under CAA §111(b) would govern CO₂ emissions, rather than regulations issued under §111(d). *See* 42 U.S.C. §7411(b), (d) (2012).

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

44. JEFFREY JONES & MICHAEL LEFF, U.S. EIA, ANNUAL ENERGY OUTLOOK 2014 ISSUES IN FOCUS: IMPLICATIONS OF ACCELERATED POWER PLANT RETIREMENTS (Apr. 28, 2014), http://www.eia.gov/forecasts/aeo/power_plant.cfm; Dan Eggers et al., *Credit Suisse: Nuclear . . . The Middle Age Dilemma?*, Feb. 19, 2013, available at <http://www.wecc.biz/committees/BOD/TEPPC/SPSG/Lists/Events/Attachments/485/Credit%20Suisse%20Nuclear%2019Feb13.pdf>.

45. 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>.

46. 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).

47. Jonas J. Monast & Sarah K. Adair, *A Triple Bottom Line for Electric Utility Regulation: Aligning State-Level Energy, Environmental, and Consumer Protection Goals*, 38 COLUM. J. ENVTL. L. 1, 21–36 (2013).

48. *See* 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).

49. U.S. EPA, POLICY ASSESSMENT FOR THE REVIEW OF THE OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS, EPA-452/R-14-006, ES.5, 3.128–3.136 (Aug. 2014).

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

51. *Sierra Club v. EPA*, No. 13-2809, 43 ELR 20233 (N.D. Cal., Oct. 29, 2013).

52. *U.S. EPA v. EME Homer City Generation*, No. 12-1182, slip op. at 2, 44 ELR 20094 (U.S. Apr. 29, 2014).

53. 42 U.S.C. §7409(d)(1) (five-year review of NAAQS); 42 U.S.C. §7411(b) (1)(B) (eight-year review of NSPSs).

54. For more information on the relationship between air quality regulations and CAA §111(d) compliance strategies, see Jeremy M. Tarr & Jonas Monast, *Beyond Carbon Dioxide: Capturing Air Quality Benefits With State Section 111(d) Plans* (Nicholas Inst. for Envtl Pol'y Solutions, Duke Univ., Working Paper No. NI-WP 14-04, May 2014), http://nicholasinstitute.duke.edu/sites/default/files/publications/wp_14-04.pdf.

sions. 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.⁵⁵

Approaches utilized by the Northwest Power and Conservation Council (NPCC) and the Tennessee Valley Authority (TVA) offer two examples. The NPCC 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.⁵⁶ TVA utilizes an in-depth, iterative “no regrets” planning framework to ensure investments are robust, regardless of future circumstances.⁵⁷

In some situations, utilities may be able to forestall major capital investments, effectively delaying large-scale expenditures, to react to preserve options for responding to new information regarding market demand, fuel prices, and regulatory requirements. By forestalling major investments, utilities conserve capital for other needs and avoid under-utilized or stranded investments if markets experience a significant shift, as many analysts have cautioned may occur.⁵⁸

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 commissioners must make a 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.⁵⁹

Demand-response and dynamic pricing options, facilitated by smart grid applications, can also forestall capacity additions. Southern Company, for example, 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.⁶⁰ 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 one year and are indexed to monthly prices.⁶¹ Examples of longer contracts include a 10-year escalating fixed price contract between Anadarko and Public Service Company of Colorado.⁶² 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.⁶³ 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 EIA's Annual Energy Outlook 2013 Reference Case natural gas price projections.⁶⁴

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 natural gas in the event the nuclear units are retired.

55. See, e.g., Patrick Bean & David Hoppock, *Least Risk Planning for Electric Utilities* (Nicholas Inst. for Envtl. Pol'y Solutions, Duke Univ., Working Paper No. NI WP 13-05, Aug. 2013), http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-05.pdf; David Hoppock et al., *Determining Least-Cost Investment for an Existing Coal Plant to Comply With EPA Regulations Under Uncertainty* (Nicholas Inst. for Envtl. Pol'y Solutions, Duke Univ., Working Paper No. NI WP 12-03, Feb. 2012), <http://nicholasinstitute.duke.edu/sites/default/files/publications/determining-the-least-cost-investment-for-an-existing-coal-plant-to-comply-with-epa-regulations-under-uncertainty-paper.pdf>.

56. NORTHWEST POWER AND CONSERVATION COUNCIL, SIXTH NORTHWEST ELECTRIC POWER AND CONSERVATION PLAN, Council Doc. 2010-09 (Feb. 2010).

57. TENNESSEE VALLEY AUTHORITY (TVA) INTEGRATED RESOURCE PLAN TVA'S ENVIRONMENTAL AND ENERGY FUTURE (Mar. 2011). For more information about planning under significant uncertainty, see also David Hoppock et al., *Assessing the Risk of Utility Investments in a Least-Cost Planning Framework* (Nicholas Inst. for Envtl. Pol'y Solutions, Duke Univ., Working Paper No. NI WP 13-07, Nov. 2013), <http://nicholasinstitute.duke.edu/climate/publications/assessing-risk-utility-investments-least-cost-planning-framework#Ux9u7T9dVJQ>.

58. See Kind, *supra* note 4; Aliff, *supra* note 31.

59. Duke Energy Carolinas (DEC), Integrated Resource Plan Annual Report (2013). DEC has already requested proposals for the 2017 natural gas capacity addition.

60. Jeff Burleson, Southern Co., Reducing Peak Demand, Presentation at the National Association of Regulatory Utility Commissioners Winter Meeting (Feb. 10, 2014), <http://www.narucmeetings.org/Presentations/Tuesday%201030am%20BURLESON.pdf>.

61. Frank C. Graves & Steven H. Levine, Brattle Grp., *Managing Natural Gas Price Volatility: Principles and Practices Across the Industry* (Nov. 2010), <http://www.cleanskies.org/wp-content/uploads/2011/08/ManagingNG-PriceVolatility.pdf>.

62. BOLLINGER, *supra* note 23.

63. 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.

64. See BOLLINGER, *supra* note 23.

The shift away from coal toward other generating resources generally facilitates management of other regulatory requirements, such as the cooling water rule and the CCR rules. 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.⁶⁵ The shift from coal to other generation resources also reduces emissions of conventional pollutants (for example, SO₂ and NO_x) and will ease compliance with the CSAPR or CAIR, as well as improve ambient air quality.⁶⁶

IV. CO₂ Limits for Existing Power Plants

A. Section 111(d) Overview

In January 2014, EPA published a proposed rule to set NSPSs for coal-fired and natural gas-fired power plants that will limit CO₂ emissions from new facilities.⁶⁷ The vast majority of rules issued under CAA §111 apply only to new sources or existing sources undergoing major modifications.⁶⁸ In this case, because the regulated pollutant (CO₂) is neither regulated as a criteria pollutant under the NAAQS program nor as a hazardous air pollutant under CAA §112, the final NSPSs for CO₂ emissions from new fossil fuel-fired power plants will trigger a requirement that states develop performance standards for *existing* power plants, subject to EPA's guidance and approval.⁶⁹

EPA and the states each play important roles in developing performance standards for existing sources. Under §111(d), EPA specifies a procedure for states to submit these standards for agency approval, a step requiring EPA to provide official guidance that clarifies the states' obligations and the criteria by which EPA will evaluate state plans.⁷⁰ In this guidance, EPA will identify the "best system of emission reduction" for reducing CO₂ emissions from existing power plants and the emissions reductions achievable using that system.⁷¹ Each state then submits a plan to EPA that establishes performance standards for existing sources.⁷² Like all performance standards under CAA §111, 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.⁷³

The CAA 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."⁷⁴ 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.⁷⁵ EPA has previously determined that emissions averaging across facilities or emissions trading can qualify as a "best system."⁷⁶ The CAA 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 CO₂ emissions. The range of available options will affect electricity generators' compliance strategies and potential to use those strategies to address other current electricity sector needs.

On June 18, 2014, EPA proposed emissions guidelines for developing state plans to limit CO₂ emissions from existing

65. 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).

66. 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 *ANNUAL OUTLOOK 2014 EARLY RELEASE*, *supra* note 16.

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

68. The proposed NSPS does not apply to major modifications. *See id.* at 1433. President Obama has instructed EPA to propose standards for modified and reconstructed power plants by June 1, 2014. *See* Press Release, Memorandum from President Barack Obama to EPA on 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>.

69. Some observers have questioned EPA's authority under CAA §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, *Federalist Soc'y, The Clean Air Act as an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions From Existing Power Plants* 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 EPA is authorized to regulate power plants under CAA §111(d)). 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. 15994, 16030-32 (Mar. 29, 2005), *vacated on other grounds*, New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008).

70. 42 U.S.C. §7411(d)(1); 40 C.F.R. §60.22.

71. 40 Fed. Reg. 55340, 53342-44 (Nov. 17, 1975); 42 U.S.C. §7411(a) & (d).

72. 42 U.S.C. §7411(d)(1).

73. 42 U.S.C. §7411(a)(1).

74. *Id.* (emphasis added).

75. *See, e.g.*, Kate Konschnik & Ari Peskoe, *Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants* (Mar. 3, 2014) (Harvard Law Sch. Envtl. Law Program); Jonas Monast et al., *Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency*, 42 *ELR* 10206 (Mar. 2012); Gregory E. Wannier, *Prevailing Academic View on Compliance Flexibility Under §111 of the Clean Air Act* (Resources for the Future Working Paper No. DP 11-29, July 2011).

76. *See* Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units (Clean Air Mercury Rule), 70 Fed. Reg. 28606 (July 18, 2005).

fossil fuel-fired power plants.⁷⁷ These proposed guidelines identify four “building blocks” that together form the proposed best system of emission reductions: improving the heat rate of coal-fired electric generating units; increasing dispatch of existing natural gas units; increasing generation from renewable energy resources, maintaining the existing nuclear fleet and, for those states with new nuclear units currently under construction, increasing nuclear generation when the new construction is complete; and increasing demand-side energy-efficiency policies and programs.⁷⁸ The proposal identifies individual state goals based on the potential for the building blocks to limit CO₂ emissions from the covered generation facilities within each state.⁷⁹

B. Potential §111(d) Compliance Strategies

The proposed rule emphasizes that states have broad flexibility in implementing §111(d) plans, and are not bound to any of the building blocks identified by EPA as the best system of emission reduction.⁸⁰ Unit-level options for reducing CO₂ 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.⁸¹ Since 2012, state officials and other stakeholders have released a range of proposals that would allow emis-

sions averaging, emissions trading (intrastate and regional), and credit for investments in energy efficiency, renewables, and nuclear energy. Another proposal is to measure total CO₂ emissions from covered units within a state and to allow that state to choose how best to achieve the required emissions reductions.⁸²

Numerous states have one or more strategies in place to limit CO₂ emissions, including renewable portfolio standards, end-use energy-efficiency programs,⁸³ and state-wide⁸⁴ and regional greenhouse gas emissions markets.⁸⁵ Many states are also seeing reductions in CO₂ emissions as electric generators retire coal-fired power plants and replace them with natural gas facilities. Each of these strategies offers the potential to achieve cost-effective CO₂ emission reductions from the power sector, and would be allowable compliance options under the June 2014 proposed rule.

V. A Multi-Benefits Framework: Addressing Electricity Sector Challenges and Complying With §111(d) Requirements

There is notable overlap between the strategies for mitigating electricity sector risks and potential compliance strategies for the §111(d) rulemaking process. This overlap presents regulators with an opportunity to pursue strategies that help manage the transition occurring in the electricity sector and achieve CO₂ reductions required under state §111(d) plans.

Electricity sector challenges and the potential for CO₂ emissions reductions from strategies to meet those challenges vary significantly by state. Discussed below are three strategies that are permitted under the proposed §111(d) guidelines and that could play a role in electricity sector

77. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34829 (June 2, 2014).

78. *Id.* at 79 Fed. Reg. 34855-58. There is notable disagreement about EPA's authority to set stringent emissions limits or to consider emissions reductions not resulting from sources subject to the §111(d) rule (for example, investments in renewable energy generation) when identifying emissions limits for existing sources. 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) (an adapted version can also be found in this issue, 44 ELR 11086), and Daniel A. Lashof et al., NATURAL RES. DEF. COUNCIL, *Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters* (2013), <http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf>, with N.C. DEPT. OF ENV'T & NATURAL RES., NORTH CAROLINA §111(D) PRINCIPLES (Jan. 27, 2014), http://www.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), <http://www.publicpower.org/files/PDFs/NSPS111%28d%29Analysis.pdf>.

79. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34829, 34895, tbl. 8.

80. See, e.g., 79 Fed. Reg. 34829, 34905 (“The 2020-2029 interim goal is expressed as a 10-year average emission rate to provide states with flexibility in designing their plans.”); *id.* at 34930 (“[T]he EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.”); *id.* at 34931:

As states implement the proposed guidelines, they have sufficient flexibility to adopt different state-level or regional approaches that may yield different costs, benefits, and environmental impacts. For example, states may use the flexibilities described in these guidelines to find approaches that are more cost effective for their particular state or choose approaches that shift the balance of co-benefits and impacts to match broader state priorities.

81. See, e.g., RICHARD J. CAMPBELL, CONG. RESEARCH SERV., INCREASING THE EFFICIENCY OF EXISTING COAL-FIRED POWER PLANTS, R43343 (2013); Massachusetts Inst. of Tech. Energy Initiative Symposium, *Retrofitting of Coal-Fired Power Plants for CO₂ Emissions Reductions* 19 (Mar. 23, 2009), <http://mitel.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 (2008), <http://www.netl.doe.gov/energy-analyses/pubs/CFPP%20Efficiency-FINAL.pdf>.

82. See, e.g., ISO/RTO Council, *EPA CO₂ Rule: ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals* 4-7 (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, California Air Res. Bd., 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, Connecticut Dept' of Energy & Env't. Prot., to Gina McCarthy, EPA Administrator (Dec. 2, 2013), available at http://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, Kentucky Energy & Env't 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); Lashof et al., *supra* note 78.

83. For a compilation of state energy efficiency and renewable energy policies, see the Database of State Incentives for Renewables & Efficiency website, <http://www.dsireusa.org>.

84. See California Air Res. Bd., Cap-and-Trade Program, <http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm> (last updated Mar. 14, 2014).

85. See generally Regional Greenhouse Gas Initiative website, <http://www.rggi.org>.

risk mitigation. Deciding on a particular strategy or strategies requires a detailed assessment of the state's energy sector and greater certainty regarding EPA's and states' choices regarding §111(d) policy design.

A. Reducing Electricity Demand Through End-Use Energy Efficiency

Increasing end-use energy efficiency is generally recognized as a low-cost option for reducing CO₂ emissions and is included in many white papers outlining §111(d) compliance strategies.⁸⁶ 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.⁸⁷ The specificity required under §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.

Beyond reductions in CO₂ emissions and emissions of other pollutants produced by fossil fuel combustion, energy-efficiency programs can provide energy savings for consumers.⁸⁸ 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 forestall-

ing 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.

B. Increasing Renewable Energy Generation

Once constructed, renewable energy resources such as wind and solar produce electricity without fuel costs and without directly emitting CO₂ and other regulated pollutants.⁸⁹ 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.⁹⁰ 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.⁹¹

Renewable energy can help hedge against natural gas price fluctuations by reducing natural gas generation, the potential for more stringent CO₂ limits, and the potential for increasingly stringent limits on criteria pollutants.⁹² 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.⁹³

C. Additional Options for Expanding Generation From Low-Carbon Energy Sources

Other options for reducing CO₂ 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.⁹⁴ Demand response—reducing electricity demand during

86. See, e.g., Commonwealth of Kentucky Energy & Env. Cabinet, Greenhouse Gas Policy Implications for Kentucky Under Section 111(d) of the Clean Air Act (Oct. 2013), <http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf>; Daniel A. Lashoff et al., Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters, NRDC Report R:12-11-A (March 2013); 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 & 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).

87. Jeremy M. Tarr et al., Nicholas Inst. for Envtl. Pol'y Solutions, Duke Univ., *Energy Efficiency and Greenhouse Gas Limits for Existing Power Plants: Learning From EPA Precedent* (Nicholas Inst. for Envtl. Pol'y Solutions, Duke Univ., Report No. NI R 13-04, June 2013), http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-04_0.pdf.

88. 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. See http://www.cepci.org/assets/HelpMyHouseBrochure_June2013.pdf.

89. Hydropower also produces electricity without fuel costs. Hydropower was not included in this Article because of low projected growth, according to EIA ANNUAL OUTLOOK 2014 EARLY RELEASE, *supra* note 16.

90. U.S. EIA, *Electric Power Monthly*, Feb. 2014.

91. See BOLLINGER, *supra* note 23; Sherwood, *supra* note 34.

92. For a discussion of the history of more-stringent environmental regulations over time, see Monast & Adair, *supra* note 47.

93. Cycling fossil generation (natural gas and coal) to integrate these intermittent resources can result in increased CO₂ and NO_x emissions rates for fossil units. See Warren Katzenstein & Jay Apt, *Air Emissions Due to Wind and Solar Power*, 43 ENVTL. SCI. TECH. 253 (2009); D. LEW ET AL., U.S. NAT'L ENERGY TECH. LAB., WESTERN WIND AND SOLAR INTEGRATION STUDY PHASE 2, NREL/TP-5500-55588 (2013).

94. 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. See Final Deferral for CO₂ Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V, 76 Fed. Reg. 43490 (July 20, 2011). In

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.⁹⁵ Its CO₂ 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, above, shows that the levelized cost of a new nuclear plant is an estimated 62% higher than an NGCC facility due to the high capital costs associated with nuclear plant construction. Although nuclear facilities are under construction in Georgia and South Carolina, obtaining approval from state public utility commissions for other such facilities in this period of demand-growth uncertainty may be difficult.⁹⁶ However, concerns about increasingly stringent CO₂ emissions limits and a desire to maintain fuel diversity could cause utility regulators and investors to view nuclear more favorably.

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 CO₂ emission limits.⁹⁷ 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 carbon emissions and sell the CO₂ for enhanced oil recovery.⁹⁸

The West Virginia PSC approved partial cost recovery for a CCS 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.⁹⁹ The cost of full-scale CCS 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 an NGCC plant, as shown in Table 1, above. 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.¹⁰⁰ Nonetheless, the combination of the proposed NSPS rule requiring any new coal-fired power plant to capture approximately 40% of its CO₂ emissions and the §111(d) rule targeting CO₂ 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.

VI. 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 CO₂ emissions. The flexibility embedded in CAA §111(d), and the fact that the §111(d) rulemaking process to limit CO₂ emissions from existing power plants coincides with a transition that is already underway, presents state regulators with an opportunity to pursue strategies that simultaneously limit CO₂ emissions and address other electricity sector needs.

2013, the D.C. Circuit vacated the deferral in *Coalition for Responsible Regulation, Inc. v. EPA*, 722 F.3d 401 (D.C. Cir. 2013).

95. See PJM, *Demand Response*, <http://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/demand-response-fact-sheet.ashx>.

96. U.S. Dep't of Energy Office of Nuclear Energy, *Quarterly Nuclear Deployment Scorecard* (Jan. 2014), <http://www.energy.gov/ne/downloads/quarterly-nuclear-deployment-scorecard-january-2014>.

97. See Order on Application for Rate Increase, Appalachian Power Co. and Wheeling Power Co., dba American Elec. Power Co., Case No. 10-0699-E-42T, West Virginia Pub. Serv. Comm'n, Mar. 30, 2011, at 47 [hereinafter West Virginia CCS Order]; Final Order on Remand, Mississippi Power Co. Application for Electric Generating Plant in Kemper, Lauderdale, Clarke, and Jasper Counties, Docket No. 2009-UA-014, Mississippi Pub. Serv. Comm'n, Apr. 24, 2012 [hereinafter Mississippi IGCC Order].

98. See Mississippi IGCC Order, *supra* note 97.

99. See West Virginia CCS Order, *supra* note 97; see also Final Order, Application of Appalachian Power Co. for Rate Review, Case No. PUE-2009-0030, Virginia State Corp. Comm'n (July 15, 2009).

100. For a detailed discussion of the Mississippi, Virginia, and West Virginia public utility commission decisions, see Jonas J. Monast & Sarah K. Adair, *Completing the Energy Innovation Cycle: The View From the Public Utility Commission*, 65 HASTINGS L.J. 1345, 1368-77 (2014).