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Further Preparing for EPA Regulations

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Foreword

In 2011, Moody's wrote,

> *…credit risk factors associated with energy and climate legislation have existed for decades and managing these risks are considered a core competency for all utility operators, whether they are regulated or un-regulated, public or privately-owned.*[1]

This applies as much today as it did several years ago when Moody's made that pronouncement. Staying abreast of changes to environmental and public health laws and their potential effects on the utility sector also continues to be an important task faced by utility regulators.

With this publication, RAP is following up on our 2011 reports, *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance,* and *Incorporating Environmental Costs in Electric Rates: Working to Ensure Affordable Compliance with Public Health and Environmental Regulations.*[2] Since then, we and many others have done a lot more thinking.

This paper revisits a number of those topics, updating regulatory proposals, identifying significant trends, and assessing market factors and related issues for regulators. It also places an emphasis on flexible provisions of these regulations and the potential for their flexible interpretation. Commissions should avoid an outcome in which they see no choice but to approve proposals to recover costs associated with compliance technology without appreciating alternatives that a utility might have considered in making its investment decision.

We hope that this paper will be helpful as you work through these issues.

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1 Moody's Investor Service. (2011). Six-Month Update. U.S. Regulated Utilities.

2 Farnsworth, 2011; and Lazar & Farnsworth, 2011.

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List of Acronyms and Abbreviations

ACI	Activated Carbon Injection
ACEEE	American Council for an Energy-Efficient Economy
AQI	Air Quality Index
BART	Best Available Retrofit Technology
BDT	Best Demonstrated Technology
BPT	Best Practicable Technology
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DEP	Department of Environmental Protection (PA)
DOE	(US) Department of Energy
DSI	Dry Sorbent Injection
EDF	Environmental Defense Fund
ELG	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
EPA	(US) Environmental Protection Agency
ETS	Emissions Trading Scheme
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan (see SIP)
GAO	Government Accountability Office
GHG	Greenhouse Gas(es)
GWP	Global Warming Potential
HAPs	Hazardous Air Pollutants
Hg	Mercury
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kW	Kilowatt
LNG	Liquefied Natural Gas
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MIT	Massachusetts Institute of Technology
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NGOs	Non-Governmental Organizations
NOAA	National Oceanic and Atmospheric Administration
NODA	Notice of Data Availability
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
PAL	Plantwide Applicability Limitation
POTW	Publicly Owned Treatment Works
ppb	Parts per Billion
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
RCRA	Resource Conservation and Recovery Act
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TPY	Tons Per Year
VOC	Volatile Organic Compound

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Executive Summary

With this publication, RAP is following up on earlier reports that looked at the effects of pending U.S Environmental Protection Agency (EPA) public health and environmental regulations on the electric industry. In this report we revisit the topic, update regulatory proposals, identify significant trends, and assess related issues for regulators, including a look at other market factors affecting plant closures.

In updating our 2011 publications, we place an emphasis on actual or potential flexible provisions or interpretations of these regulations. This reflects the reality that not all of these regulations are as rigid as often characterized, that the EPA is more approachable than one might presume, and that companies often have various compliance options available to them. This report should help commissions to frame relevant questions regarding company compliance proposals and to be better positioned to make informed decisions in cases in which utilities request recovery of their costs to comply with these regulations.

In order to better understand each of these new or pending regulations, this report recommends that energy regulators continue to engage in discussions with state environmental regulators to determine the amount of generation capacity serving their jurisdictions that will be subject to these rules and the extent of the potential effects that they should expect. State regulators should also consider regular engagement of generation owners and operators to get firsthand knowledge of the issues they are facing as they come into compliance.

This report should be helpful to energy regulators in their efforts to understand the broad parameters of these new and pending regulations. It should also provide sufficient background on these rules to enable regulators to further explore choices companies are proposing as they plan their investments to comply with these regulations, and as companies come before commissions to recover the resulting costs.

The first part of the report looks broadly at the general structures of new and pending water, solid waste, and air regulations – as of November 2013 – with an eye to compliance flexibility. The second part of the report looks generally at recent literature identifying not only the potential effects of new EPA regulations but also other market factors currently affecting generator retirement decisions.

Part I

The EPA has developed regulations under its Clean Water Act (CWA) and Resource Conservation and Recovery Act (RCRA) authority. These regulations focus on cooling water structures (CWA), toxic effluent discharges (CWA), and coal combustion residuals (RCRA). The EPA has also developed a number of standards and regulations under its Clean Air Act authority. These include National Ambient Air Quality Standards (NAAQS), the Cross-State Air Pollution Rule, the Mercury Air Toxics Rule, and various rules related to greenhouse gases (GHG), including New Source Performance Standards for GHG emissions from new and existing fossil generation sources.

316(b) Rule

The "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities" rule proposes standards for cooling water intake structures at all existing power generating facilities as part of implementing Section 316(b) of the CWA. Its central purpose is to substantially reduce the harmful effects of "impingement"(when fish are unable to swim away from water intake) and "entrainment" (when small organisms pass through the screens and become caught in the cooling system).

A facility should be able to meet impingement requirements one of two different ways. The facility would either be subject to an upper limit on the percentage of impinged fish, or would need to demonstrate a maximum through-screen velocity of cooling water. Entrainment requirements are less clear. The proposed rule provides for the permitting authority to explore various factors

that would inform the appropriate choice of entrainment protections to be applied at any given facility. In the proposed 316(b) rule there appears to be flexibility in meeting impingement requirements, whereas flexibility in achieving entrainment requirements is less clear.

In the last several years there has been concern over the potential threat to resource adequacy from generation units being rendered uneconomic owing to the potentially high cost of installing closed-cycle cooling pursuant to this rule. Because the EPA is not proposing closed-cycle cooling for existing plants, this specific cost challenge should not be a concern for utilities or commissions. However, water scarcity is an additional aspect of resource adequacy/system reliability that may constrain the options (i.e., more water-intensive solutions) available.

Effluent Limitations Guidelines

The "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category" (ELG or rule) focuses on toxic pollutants that power plants release into wastewater and ash ponds largely as part of the flue gas desulfurization (i.e., "scrubbing") process.

In its proposal, the EPA has set out best available technology alternatives for direct and indirect discharges of these toxic pollutants. These alternatives do not lend themselves to flexible interpretation. However, if the compliance entity is a direct discharger, depending on its permit renewal schedule, it could have some timing flexibility. After the rule is finalized there will be some amount of time before direct dischargers are required to implement the rule, because relevant standards will be incorporated into permits that are renewed on a five-year cycle.

Coal Combustion Residuals Rule

The rule associated with the "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities," is also referred to as the coal combustion residuals (CCR) rule. The rule would set out requirements for parties that create, transport, or store CCRs, including permitting, ground water monitoring, and financial assurance.

The EPA's proposed CCR regulations contain the potential for compliance flexibility. The EPA has indicated the possibility that it would proceed and develop the regulation under Subtitle D, which would result in characterizing CCRs as ordinary solid waste rather than the Subtitle C approach, which would treat them as hazardous waste.

Furthermore, the EPA is considering coordinating ELG requirements with the CCR rule, which could result in the control of pollutants under one program, significantly affecting the degree to which they need to be controlled under the other program. This could translate into lower costs to compliance entities, and ultimately to utility ratepayers. In reviewing utility compliance planning, regulators could encourage utilities to take advantage of both the opportunity to comment and – assuming the proposed provisions are adopted – the opportunity to exploit potential benefits of coordination between the two rules.

NAAQS

National Ambient Air Quality Standards (NAAQS) are established by the EPA for a limited set of "criteria" pollutants, including ground-level ozone, nitrogen dioxide, particulates, and sulfur dioxide (SO_2). NAAQS do not impose direct compliance requirements on electricity generators, but instead apply to states. The EPA designates whether areas are in compliance with these standards, that is, in "attainment" or "nonattainment," and states must find ways to ensure that their air quality does not fall below these standards. State plans for addressing these air quality requirements are known as State Implementation Plans (SIPs).

Parts of SIPs that are developed by states in order to come into compliance can affect individual generators. Emitters in nonattainment areas could face regulatory requirements that are more stringent and costly than those in areas that meet NAAQS. Requirements could include enhanced regulatory oversight such as permitting requirements, and state economic development sanctions such as the need to purchase emissions offsets for a newly developed project.

There are three NAAQS of which utility commissions should be aware. Two are existing standards and one is likely to be proposed in 2014. In December 2013, the EPA was ordered by a federal court to fully implement 2010 NAAQS for SO_2, meaning that there is the potential for additional counties around the country to be found to be in nonattainment for that standard.[3] In the next year, states can also expect to be faced with the implementation of

3 *Sierra Club et al v. EPA*, 2013.

new standards for particulate matter and a new proposal for ozone. In both cases, additional counties around the country will be found to be in nonattainment. In the case of each of these NAAQS, affected states will need to develop SIPs, which could affect individual power generators.

The Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR), designed to address interstate transport of pollutants in the eastern two-thirds of the country, was vacated and stayed by the Circuit Court for the District of Columbia and is now being reviewed by the Supreme Court. Immediate action on this rule is not expected, although the Court will issue a ruling sometime in 2014. States are pursuing other options available to them, and downwind plaintiffs are utilizing other sections of the Clean Air Act to sue upwind sources of air pollution. The EPA is also required by law to address interstate transport of pollution. So despite CSAPR being reviewed in the courts, arguably, upwind emissions sources continue to be at some risk for Clean Air Act violations owing to their downwind effects.

The Mercury Air Toxics Rule

The Mercury Air Toxics Rule establishes the first national standard to reduce mercury and other air toxics from power plants by setting performance standards for mercury and other toxic heavy metals, acid gases, and certain toxic organic compounds. It is already in place with a three-year time frame for generators to come into compliance. Although it is subject to court challenge, the court has not stayed the rule and it remains in effect pending the outcome of that challenge.

The program allows generators to request an additional (fourth) year from regulators in order to come into compliance. Based on information developed by the National Association of Clean Air Agencies, numerous successful applications have been made for fourth-year extensions.

New Source Performance Standards for New Sources (NSPS) – Section 111(b)

In an effort to address GHG emissions from the electric sector, which accounts for approximately one-third of all domestic GHG emissions, the EPA has proposed NSPS for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units.

The EPA is proposing two limits for fossil fuel-fired utility boilers and integrated gasification combined cycle units that allow compliance entities a choice between two compliance periods.

- 1100 lb CO_2/MWh gross over a 12 operating-month period, or
- 1000 to 1050 lb CO_2/MWh gross over an 84 operating-month (7-year) period

The EPA is proposing two standards for natural gas-fired stationary combustion units, depending on size. The proposed limits are based on the performance of modern natural gas combined cycle units. These proposed limits are:

- 1000 lb CO_2/MWh gross for larger units (>850 mmBtu/h)
- 1100 lb CO_2/MWh gross for smaller units (≤850 mmBtu/h)

The EPA's NSPS for new sources requires new coal-fired units to install "partial" carbon capture and sequestration technology ("CCS") as the best system of emissions reduction to lower CO_2 emissions. The 84-month compliance period, in the EPA's view, provides flexibility. Although a lengthy compliance period would suggest significant flexibility, there is disagreement as to whether new coal-fired generators could meet the rule's requirements. There appears to be no agreement as to whether CCS has been adequately demonstrated and is thus available for compliance purposes.

New Source Performance Standards for Existing Sources – Section 111(d)

The EPA is expected to propose NSPS for GHG emissions from existing power plants by June 2014. Section 111(d) of the Clean Air Act sets out a two-step federal and state process that the Supreme Court summarized as, "for existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction."

Although referred to as "guidelines," these will be binding requirements that states will have to address when they develop plans to regulate the existing sources in their jurisdictions and a schedule for doing so. The guidelines must reflect "the application of the best system of emission reduction…that has been adequately demonstrated." One of the central issues facing the EPA is the question of how emissions reductions will be achieved. The EPA has noted that generators might realize some limited efficiencies and related emissions reductions "within the fence," that is,

through onsite technology investments. But some advocates are urging the EPA, as it develops guidelines, to count potential GHG reductions available from other parts of the electric system.

In compliance with the EPA's guidelines, and subject to EPA approval, Section 111(d) requires states to issue performance standards. The EPA and the states must also follow a procedure similar to the SIP process outlined in Section 110 of the Clean Air Act. SIPs, often referred to as "equivalency plans" in this context, contain a state's strategies for complying with the EPA's emissions guidelines, and provide justification for the proposed approaches.

By employing Section 110 as the template for state action, Congress has provided states with significant leeway in identifying the means at their disposal to meet 111(d) requirements. Section 110 directs states to employ "enforceable emission limitations" in their plans, ensuring the ability of states to take action to control pollution. Owing to the short time-line, states should immediately take the opportunity to explore the full range of potential means of reducing GHG emissions in their state's electric sector. States can take the initial step by cataloguing categories of available or potentially available resources, including inside-the-fence compliance options, upon which states could rely in developing an Equivalency Plan.

As states assess the suitability of compliance resources available under each module, the potential next step might be to determine, for example, what programs the state is currently supporting and which could use more support, what new programs the state might consider undertaking, and the steps needed to put such efforts in motion.

In familiarizing oneself with these regulations and their implementation timetables, and in establishing relationships with sister regulatory agencies and national organizations to monitor the status of these regulations, energy regulators should be able to keep track of these regulations and have a sense of their potential effects on their state's power sector.

Part II

Part II of this report takes a look at recent literature identifying not only the potential effects of new EPA regulations but also at other market factors currently affecting generator retirement decisions. It has become evident over the last several years that the EPA's public health and environmental regulatory initiatives play a part in a larger constellation of factors that affect the power generation sector and utility decision-making.

The paper looks at the following factors and seeks to outline enough about them to provide guidance to regulators interested in understanding them in greater detail: (1) decreasing cost of natural gas; (2) underused natural gas generation capacity; (3) inherent efficiency of modern combined cycle natural gas plants; (4) increasing cost of coal; (5) increasing cost to transport coal; (6) age of coal fleet; (7) flat and decreasing demand; (8) increasing competitiveness of renewable energy; and (9) poor load forecasting.

A review of many of these market factors, including compliance decisions related to newer public health and environmental regulations, is instructive for regulators trying to appreciate the relative risks being faced by the generators serving their jurisdiction. Appreciation of the role that all of these factors, including EPA regulations, play will help regulators as they endeavor to understand the reasonableness of company compliance proposals and situate themselves to make informed decisions in cases in which utilities request recovery of their costs to comply with these regulations.

I. Introduction

As we noted in our 2011 publication, *Preparing for EPA Regulations,* the ability of utility regulators to respond to the challenge of the EPA's new health and environmental regulations will be tested:

> *Traditionally, regulatory goals have included ensuring electric system reliability, promoting resource adequacy, and capturing lower energy bills for ratepayers. Now utility regulatory commissions and energy planning bodies will need to work with environmental regulators and utilities to find ways to meet these traditional goals and to achieve affordable environmental compliance at the same time.*[4]

By engaging with utilities and with other regulators on these topics, utility commissions will be better prepared to evaluate a wider array of potential compliance options, and to strike their preferred balance of cost and other policy goals, including the most affordable and reliable compliance scenarios associated with various EPA public health and environmental regulations.

Although utility regulators will not need to become environmental regulators, a general understanding of the EPA's rules will be required in order to understand whether a utility's environmental compliance expenses are necessary and prudent. Meeting this challenge will also call for up-to-date utility data and a methodical review of energy system "alternatives" specific to individual states and regions. This should include not only generation alternatives across the system, but also demand and delivery alternatives. With an understanding of alternatives available to the states and to companies, utility regulators will be better equipped to identify prudent choices and work effectively with their utilities and state environmental regulators in meeting the goals of a cleaner, reliable, and affordable electric system.[5]

Integrated resource planning (IRP) is one approach that would enable company and utility commission planners to agree upon a scope of inquiry, investigate various supply- and demand-side options, evaluate potential plans, and consider approaches to monitor and revisit plans as necessary. The value in having this structured look-ahead, regardless of how formal the administrative process is, lies in being able to identify a resource mix for one's state before capital is committed to expenditures. This is the case in a traditionally regulated environment in which a utility will seek approval of expenditures. It is also the case with restructured states, where decisions about default service or transmission expansions, for example, can be shaped to reflect least-cost and least-risk opportunities. In both cases, the "least-cost" criterion implies "the lowest total cost over the planning horizon, given the risks faced."[6] And the best resource mix is one that "remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution."[7]

It should be emphasized that states and companies need not conduct formal IRPs to prepare themselves to respond effectively to the challenges associated with complying with these public health and environmental regulations. The notion of "Integrated Environmental-Compliance Planning" is a concept that has been explored in the last several

4 Farnsworth, 2011.

5 For example, under Ohio law an electric distribution utility may file an application for public utilities commission approval of an electric security plan, which can provide automatic recovery of various prudently incurred costs including "reasonable allowance for … an environmental expenditure." Ohio Rev. Code Ann. §4928.143(B)(2)(a) and (b). Even in cases in which the law allows for automatic recovery, as is the case with this statute, there is often the ability for regulators to consider alternatives available to the company and whether or not, given those alternatives, the company decision and request for rate recovery is a reasonable one.

6 Lazar, 2011 at 73; see also Farnsworth, 2011 at pages 20–38 for a more detailed discussion of integrated planning.

7 Lazar, 2011 at 73.

years.[8] It is an approach that, in many ways, works like an IRP, by considering supply-side, demand-side, and delivery options in an integrated manner. It focuses, however, more closely on the requirements of the EPA's new and forthcoming regulations. Whether commissions rely upon formal IRPs or another approach, reviewing investments ahead of time in an "integrated" manner is the key:

> *Responding to these requirements piecemeal will result in inefficient and unnecessarily expensive decisions. The sheer number and wide coverage of these pending rules mandates that the Commission and the utilities consider their potential impact in a comprehensive, rather than case-by-case basis, for both planning and cost recovery. The Commission should expect to see the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals. Given the capital-intensive and long-lived nature of investments in the electric industry, if the final form or timing of a regulation is unknown, the analysis should include both an expected value of the cost of compliance and the range of plausible costs.*[9]

Not only do state energy regulators find themselves having to reach beyond their traditional regulatory boundaries in having to understand the effects of public health and environmental regulations on the energy sector, the EPA and regulated entities too are being asked to move beyond their typical modes of operation. In reviewing GHG NSPS State Equivalency Plans for existing sources, the EPA will likely be petitioned to allow state clean energy programs to count toward compliance. At this point, it is unclear whether, in setting emissions guidelines and reviewing performance standards, the EPA will recognize these dispersed but low-cost options rather than relying solely on more expensive, site-specific, compliance technologies that can be expected to secure minimal GHG reductions. And the generators themselves, in the context of GHG NSPS for new resources, are being asked to stretch further than they think they can in order to start to deploy carbon capture and sequestration technology, which many contend is nowhere near or likely to be near market for many years.

This paper is not meant to provide the latest numbers on compliance options and costs, or a "silver bullet" designed to address all problems. Rather it highlights key issues and provides a variety of viewpoints and questions that regulators could consider and build upon as they evaluate these matters, and as they assess utility preparedness to respond to these challenges. The suggestions are meant to be considered and then tailored by the reader to his or her local conditions.

Finally, this paper is designed for readers to consider individual regulations and their implications "à la carte," without having to read earlier sections before getting to specific regulations of interest.

8 Colorado's "Clean Air – Clean Jobs Act" (HB 10-1365) is another example of Integrated Environmental-Compliance Planning. The Act anticipates new EPA regulations for NOx, SO_2, particulates, mercury, and CO_2. It requires Colorado's two investor-owned utilities to consult with the Colorado Department of Public Health and Environment on utility plans to meet current and "reasonably foreseeable EPA clean air rules," and to submit a coordinated multi-pollutant plan to the state Public Utilities Commission; see Colorado Legislative Council, 2011.

9 Oklahoma Corporation Commission, 2011. Sierra Club, 2011 at page 5.

10 See e.g., Richmond Times Dispatch, 2013. In October 2013 the Virginia Supreme court ruled that Appalachian Power can recover only $6 million of $33.3 million in disputed environmental costs, that the State Corporation Commission used flawed methodology in denying recovery of those costs, but that the commission's denial of $27.3 million in environmental costs embedded in the capacity equalization charges Appalachian Power paid to its affiliates was appropriate. Id. (Next page)

II. Part I: New Public Health and Environmental Regulations

Part I of this report reviews federal water, solid waste, and air regulations that can be expected to affect the energy sector. The purpose of focusing on the flexible provisions of these regulations, or even the potential for their flexible interpretation is to provide energy regulators with a broad perspective on compliance options available to utilities to help ensure that commissions are not limited in their review of compliance alternatives available to companies. Furthermore, with respect to proposed rules for which comment periods are still open, appreciating options that may be available is important, because informed PUC advocacy can be of great use to the EPA as it promulgates it regulations.

With the high cost of various pollution control options, utilities have a significant incentive to minimize their risk by transferring more and more costs to consumers. Furthermore, in the very commonplace scenario in which regulators have to work with individual affiliates of multistate utilities that are in a position to render revenues to their parent company, understanding the reasonable range of environmental costs even if not incurred in your state becomes an even greater challenge.[10] Therefore, an appreciation of where these regulations provide compliance entities some choices will give regulators a better understanding of the reasonableness of costs for which companies will seek recovery, and serve as a guide for questions that utility regulators should be asking.[11]

A. Water and Solid Waste Regulations

The EPA has developed regulations under its Clean Water Act (CWA) and Resource Conservation and Recovery Act (RCRA) authority. These regulations focus on cooling water structures (CWA), effluent discharges (CWA), and coal combustion residuals (RCRA).

1. Cooling Water Intake Structures at Existing Facilities – CWA Section 316(b)

316(b) Rule

- Proposed Rule, April 2011
- Notices of Data Availability, June 11, 12, 2012
- Final Rule (orig. subject to a settlement agreement to take final action on November 4, 2013, prior to government closure) TBD
- Implemented via National Pollutant Discharge Elimination System (NPDES) permit process (5-year renewals)

a) Background

In April 2011, the EPA published, "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities" (316b Rule), a rule proposing standards for cooling water intake structures at all existing power generating facilities as part of implementing Section 316(b) of the CWA (See Appendix 4 – The Clean Water Act in Brief).[12]

In June 2012, the EPA also issued two Notices of Data Availability (NODA) that reflect comments received by the EPA on its 316(b) proposed rule. In its June 11, 2012 NODA, the EPA presented new data and information it received and collected since the proposed rule was first published.[13] The EPA indicated that it may rely on these

11 For a more complete discussion of mechanisms for including regulatory compliance costs in rates, see Lazar & Farnsworth, 2011.

12 National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities, 2011. The EPA derives its authority over cooling water discharges and water permitting from the CWA 33 U.S.C. §1251 et seq.

13 U.S. EPA, 2013i. See also: National Pollutant Discharge Elimination System—Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities; Notice of Data Availability Related to Impingement Mortality Control Requirements, 2012

data in developing a definition of "impingement mortality" and compliance alternatives, both of which are described further below.[14] The second NODA, published on June 12, 2012, also contains additional new data and information the EPA received and collected since the proposed rule was published.[15]

The central purpose of the rule is to substantially reduce the harmful effects of "impingement" and "entrainment." Fish and smaller organisms die because they are either unable to swim away from water intakes and are "impinged" against the screen, or pass through screens and become "entrained" in the cooling system. The withdrawal of cooling water by facilities removes billions of aquatic organisms from waterways each year, including fish, crustaceans, shellfish, marine mammals, and other aquatic life. Most impacts are to early life stages of fish and shellfish. Incidents of impingement and entrainment can go almost unnoticed or can be so pronounced that, under certain circumstances, a power plant needs to shut down, as was the case at the Diablo Canyon nuclear facility in 2012 when jellyfish-like organisms clogged intake pipes.[16]

Section 316(b) of the CWA requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available or "BTA" for minimizing adverse environmental impacts. The EPA has promulgated and revisited cooling water intake rules under Section 316(b) in various phases for new and existing sources since 1976.

b) Applicability

The proposed 316(b) rule being considered here focuses on existing sources that withdraw more than two million gallons per day and use at least 25 percent of the water exclusively for cooling purposes. The EPA estimates that approximately 670 of 1260 such facilities are power plants.[17] 316(b) standards are implemented through the CWA's NPDES permit process. In other words, as qualifying facilities come in for permit renewals (every five years) their permits would be modified to conform to the 316(b) standards that the EPA adopts.

Impingement Requirements

According to the proposed rule, a facility would be able to meet impingement requirements one of two ways. The facility would either be subject to an upper limit on the percentage of impinged fish, or would need to demonstrate a maximum through-screen velocity of cooling water. More specifically, under the first approach, the facility operator must monitor for "impingement mortality" and demonstrate that (1) the annual average mortality is no more than 12 percent, and (2) the maximum monthly average is 31 percent or less.[18] An operator choosing the second approach would need to demonstrate that through-screen cooling water velocities do not exceed 0.5 feet per second or less. This is supposed to allow most fish to safely swim away from the screens and thus avoid impingement.[19]

Entrainment Requirements

Entrainment requirements are less clear. The proposed rule provides for the permitting authority, in the permitting process itself, to explore various factors that would inform the appropriate choice of entrainment protections.[20] Thus, the establishment of an entrainment standard in a permit will involve due consideration of site-specific factors, such as potentially affected species, mix of species, biology of the water, and operational aspects of the facility. Larger

14 U.S. EPA, 2012d.

15 The new data are related to the results of the EPA's stated preference survey to estimate total willingness to pay for improvements to fishery resources affected by facilities that would be subject to 316(b).

16 See e.g., Peach, 2013. Officials at Oskarshamn nuclear power plant in Oskarshamn, southeastern Sweden had to shut down one of the plant's reactors on Sunday, September 29, 2013 after tons of jellyfish clogged up pipes bringing cooling water to the plant. "Jellyfish are not a new problem for nuclear power plants. Last year the California-based Diablo Canyon facility had to shut its reactor two after gobs of sea salp — a gelatinous, jellyfish-like organism — clogged intake pipes. In 2005, the first unit at Oskarshamn was temporarily turned off due to a sudden jellyfish influx." Id.

17 The EPA estimates that 590 of these facilities are manufacturers. U.S. EPA, 2013i.

18 National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 2011.

19 Burnett and Englert, 2011.

20 The CWA authorizes the delegation of permit issuance authority to states. CWA § 402(b), 33 U.S.C. § 1342(b). Not all states, however, are currently authorized. In such instances, the EPA may be the permit writer.

facilities, that is, those that withdraw at least 125 million gallons a day, would be required to develop studies to help their permitting authority determine the types of site-specific controls necessary to reduce entrainment mortality.

c) Compliance Options

In this rule, the EPA has not proposed closed-cycle cooling as a mandatory compliance technology for existing sources, as had been expected by some.[21] However, in cases where existing facilities add new units requiring cooling, the facility would be required to add technology that is equivalent to closed-cycle cooling. A closed-cycle system discharges heat through evaporation in cooling towers and recycles water within the power plant. Closed-cycle systems thus require relatively little water, because the need is limited to the amount lost through the evaporative process.

The EPA has identified two technologies designed to limit impingement mortality. The first is a "traveling screen," essentially a vertical conveyor belt comprised of screen segments that catch objects (e.g., fish) drawn into cooling water intake streams and automatically clear before returning to catch more. As mentioned earlier, the second approach is to reduce through-screen velocity to less than 0.5 feet per second.[22]

The effectiveness of traveling screens can be enhanced by pairing them with additional fine-mesh screens; fixed-panel screens; wedge wire screens; barrier nets (especially to address high impingement events due to seasonal migration); and aquatic filter barriers suspended by floatation devices.[23] Facility operational measures such as the use of variable speed drives and flow optimization may also be useful in providing impingement and entrainment protections.[24]

Potential Flexibility and Uncertainty

Under the 316(b) rule there appears to be potential for flexibility in meeting compliance requirements. There are significant potential lead times owing to the requirement that 316(b) standards be implemented via the NPDES permit process that renews existing permits in five-year cycles.

As noted earlier, the 316(b) rule also provides existing sources with several choices of how to comply with BTA standards for impingement. The EPA has provided the permitting authorities and compliance entities with flexibility by not adopting a single technology like closed-cycle cooling. This may be partly attributable to the recognition that there is not one best technology that would apply around the country. This may also be owing to a long history of litigation over 316(b) requirements and the resistance by compliance entities. If the EPA's proposed rule were adopted it would leave the compliance technology decision largely to the authorized state agencies whose staff will have to rely largely on data provided by the compliance entity and the permit writer's site-specific judgments as to what is appropriate.[25]

For addressing entrainment mortality, the rule provides for facilities to study and develop information as part of the permit renewal process, and then establishes a process by which the best technology available for that facility would be determined. Because of the open-endedness of the entrainment requirements, it is possible that permit writers and facilities will need to take time to accommodate facilities and to acquire sufficient information upon which to base permit requirements and conditions.

Various commentators on the rule have noted that there is also some uncertainty that comes with the EPA's 316(b) proposal. According to John Burnett and Dr. Thomas Englert, authors of "Understanding the Proposed §316(b) Rule for Cooling Water Intake Structures at Existing Facilities," permitting authorities will play a big part in the compliance requirements that facilities ultimately face:

> *The approach owners and managers should take toward planning for compliance will depend to a large extent on their individual permitting authority's approach, given that entrainment requirements are based on the permit director's best professional judgment.*[26]

From the point of view of a number of NGOs such as Riverkeeper, electric generators are at even greater risk, and their ability to provide electricity is more uncertain

21 See e.g., Burnett and Englert, 2011. "What does [316(b)] get right? It does not mandate closed-cycle cooling retrofits at all facilities." Id.

22 Burnett and Englert, 2011.

23 Burnett and Englert, 2011; see also Henderson and Clubb, 2013.

24 Id.

25 The EPA notes that a permitting process does not occur behind closed doors because the public is allowed to participate in the permitting process. If a facility applies for an NPDES permit, "the permitting authority or company will have provided notice in a major local newspaper, usually in the legal section of the classified ads, or in an official publication such as the Federal Register." U.S. EPA, 2013.

26 Burnett and Englert, 2012.

if the EPA does not require them to use closed-cycle cooling. They contend that "states miss the links between ensuring a reliable supply of energy and environmental protection." Closed-cycle cooling, they maintain, increases the reliability of the power grid during droughts and heat waves, but because some states analyze "energy" and "the environment" separately, states do not consider the full benefits of closed-cycle cooling in their analysis.[27]

This regulatory shortcoming and risk associated with plant cooling choices was alluded to by the National Association of Regulatory Utility Commissioners (NARUC) at its 125th Annual Meeting in Orlando, Florida in November 2013. NARUC adopted a resolution entitled "Resolution in Support of Water-Smart Energy Choices," in which it recognized the same risks:

- Power plant cooling water needs can affect power plants, water resources, and other water users, through water withdrawals, water consumption (evaporation), water temperature effects, and other water quality impacts; and
- Water-related constraints to generation plants can reduce electricity supplies, threaten reliability and increase costs….[28]

NARUC resolved to, among other things:

- Recognize the important role of water supply and related risks in making sound power supply investment decisions and allocating water-related risks and benefits;
- Seek input from water resource agencies, water commissions, and other relevant stakeholders on the long-term effects of power supply decisions (including new construction, retrofits, and retirements) on the broader water supply and demand; and
- Take appropriate additional steps to reduce near- and long-term electricity-water risks, including reducing the water intensity of power generation…[29]

d) Recommendations

In the proposed 316(b) rule there appears to be flexibility in meeting impingement requirements, whereas flexibility in achieving entrainment requirements is less clear. Given current uncertainty as to how the rule will be finalized, it would be valuable for energy regulators to engage in discussions with state water regulators to determine the amount of generation capacity affecting their jurisdiction that will be subject to this rule, and to gain a sense of the likely cost of compliance that generators can expect to face. Especially in restructured jurisdictions, state regulators might also consider directly engaging generation-owners and operators to ascertain their perspectives on relative costs and operational risks to which generation units may be subject.

In the last several years there has been concern over the potential threat to resource adequacy from generation units being rendered uneconomic owing to the potentially high cost of installing closed-cycle cooling. The EPA is not proposing closed-cycle cooling for existing plants. However, there is an additional aspect of reliability that has emerged more recently that regulators should understand. It may be that reliance on more water-intensive cooling solutions would bring unacceptable risks associated with the continued availability of water itself. Engaging non-governmental organizations (NGOs) and state natural resources experts would help develop a record on these issues that a commission might find useful, as they will likely be asked in many jurisdictions to assess costs associated with 316(b) compliance in proposals seeking recovery for compliance costs.

2. Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

ELG Schedule

- Notice of Proposed Rulemaking, April 19, 2013
- Proposed Rule June 7, 2013
- Publication Date, July 12, 2013
- Final Rule, May 2014
- Compliance (Part of NPDES 5-year cycle) post 2017

a) Background

On June 7, 2013, the EPA proposed revisions to the "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category" (ELG or rule).[30] Relying on technology improvements in the steam electric

27 Super, Rotenberg,& Hankovszky, 2013.

28 National Association of Regulatory Utility Commissioners, 2013b.

29 Id.

30 The EPA is relying on the authority found in Sections 301, 304, 306, 307, 308, 402, and 501 of the CWA. "This category is comprised of plants that produce electricity from a process utilizing fossil or nuclear fuel in conjunction with a thermal cycle employing the steam/water system as the thermodynamic medium." Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 2013.

power industry over the last three decades, the EPA's proposal establishes the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants.

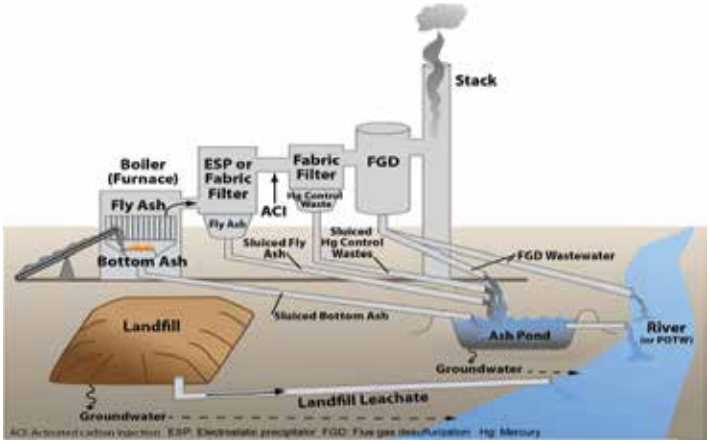
The major focus of the Effluent Rule is on toxic pollutants that power plants release into wastewater and ash ponds as part of the flue gas desulfurization (FGD) process. Most existing power plants release substantial amounts of water used in boilers, cooling systems, and pollution control systems back into the environment. The EPA indicates that the proposed rule would strengthen the controls on various discharges from electric generating plants by revising the technology-based effluent limitations guidelines and standards that apply to both direct discharges of wastewater and also indirect discharges to publicly owned treatment works.

b) Applicability

Steam electric power plants alone contribute 50 to 60 percent of all toxic pollutants discharged to surface waters by all industrial categories currently regulated in the United States under the CWA.[31] As illustrated in Figure 1, coal plants produce various combustion byproducts, liquid and solid. Discharges regulated under the proposed rule include: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and waste water from flue gas mercury control systems and gasification systems.

Figure 1

Key Waste Streams[32]



c) Compliance Options

Like the standards established under the new 316(b) rule, ELG standards for direct dischargers are implemented through the NPDES permit process. As facilities come in for permit renewals (every five years) their permits would

Table 1

Preferred Alternatives for Existing Sources That Discharge Into Surface Water

Option	Best Available Technology (BAT) Alternatives
3a	• For fly ash transport water and wastewater from flue gas mercury control system discharges – zero discharge effluent limit • For gasification process discharges – numeric effluent limits for mercury, arsenic, selenium, and total dissolved solids • For nonchemical metal cleaning waste discharges – numeric effluent limits for copper and iron • For bottom ash transport water and CCR residual leachate from landfills/surface impoundments – numeric effluent limits for total suspended solids, oil, and grease that are equal to the current BPT[33] effluent limits for these discharges • FGD wastewater – determine on a site-specific basis
3b	• FGD wastewater for plants with a total wet scrubbed capacity of 2000 MW or greater – numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite • All other proposed Option 3b requirements are identical to the proposed Option 3a requirements described above
3	• FGD wastewater (exception for plants that are 50 MW or smaller or oil fired) – numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite • All other proposed Option 3 requirements are identical to the proposed Option 3a requirements described above
4a	• Bottom ash transport water from units that are greater than 400 MW – zero discharge for all pollutants • All other proposed Option 4 requirements are identical to the proposed Option 3 requirements described above

31 Effluent Limitations Guidelines and Standards, 2013.

32 U.S. EPA, 2013a.

33 I.e., "Best Practicable Technology." See Section 304(b)(1) of the Clean Water Act. EPA sets BPT effluent limitations for conventional, toxic, and non-conventional pollutants. See generally, U.S. EPA, 2013h.

Selected CWA Standards

Under the CWA, there are different levels of technology-based limitations that apply, depending on the type of pollutant being discharged (conventional, toxic, and nonconventional), and whether the discharger is an existing or new source. Despite being based on appropriate technology, dischargers are not required to use any specific technology to meet these limits.

Best Available Technology Economically Achievable (BAT)— Section 304(b)(2) of the CWA

Industrial dischargers are required to achieve effluent limitations based on the best available technology economically achievable or "BAT." BAT applies to toxic and nonconventional pollutants, and are set at levels that are supposed "will result in reasonable further progress the national goal of eliminating the discharge of all pollutants..." 33 U.S.C. 1301(b)(2)(A).

New Source Performance Standards (NSPS) — Section 306 of the CWA

NSPS are supposed to reflect effluent reductions that are achievable based on the best available demonstrated control technology. New sources have the opportunity to install the best and most efficient production processes and wastewater treatment technologies.

Pretreatment Standards for Existing Sources (PSES) — Section 307(b) of the CWA

PSES are national, uniform, technology-based standards that apply to indirect dischargers, that is, dischargers to POTWs from specific industrial categories. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTW.

Pretreatment Standards for New Sources (PSNS) — Section 307(c) of the CWA

PSNS are national, uniform, technology-based standards that also apply to indirect dischargers. They are designed to prevent the discharges of pollutants that are incompatible with the operation of POTWs. The EPA issues PSNS at the same time as NSPS, and considers the same factors.

be modified to conform to the ELG standards that the EPA adopts. For indirect dischargers, pretreatment standards are implemented through the national pretreatment program.

The EPA is considering several options in this rulemaking and has identified four preferred alternatives for regulation of discharges from existing sources. These four preferred alternatives are summarized in Table 1.

Depending on the option, the EPA is proposing to revise or establish standards that apply to new or existing plants that discharge directly into waterways or indirectly into publicly owned treatment works (POTWs). See "Selected Clean Water Act Standards" text box.

d) Recommendations

In its proposal, the EPA has set out best available technology alternatives for direct and indirect discharges of toxic pollutants. These alternatives do not lend themselves to flexible interpretation. However, if the compliance entity is a direct discharger, depending on its permit renewal schedule, it could have some timing flexibility. After the rule is finalized there will be some amount of time before direct dischargers are required to implement the rule, because standards for direct dischargers are incorporated into permits that are renewed on a five-year cycle.

Energy regulators should engage state water regulators or the companies themselves to gather relevant information on the effects that the rule is likely to have on jurisdictional generators, including the amount of generation capacity affected, likely costs of compliance, and time-frame for permit updates. In restructured jurisdictions, state regulators could engage system operators and generation-owners and operators directly.

Because the EPA is considering coordinating ELG requirements with the proposed CCR rule, energy regulators should keep in mind that controlling pollutants under one program may affect the degree to which they need to be controlled and the resulting costs under the other program.

3. Coal Combustion Residuals

- Proposed on June 21, 2010
- EPA Status Report to DC District Court due December 31, 2013
- Final Rule TBD

a) Background

On June 21, 2010, the EPA proposed rules related to "Hazardous and Solid Waste Management System;

Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities" (CCR rule). CCRs are byproducts of the combustion of coal in steam electric power plants. They include coal ash and FGD waste.

On September 30, 2013, the U.S. District Court for the District of Columbia issued a decision granting summary judgment to *Appalachian Voices, et al,* on their claim that the EPA needs to review and revise its CCR rule.[34] On October 29, 2013, the Court issued a memorandum decision agreeing with advocates that Section 2002(b) of RCRA requires the EPA to review, and if necessary revise, its coal ash rules every three years.[35] The court indicated that the EPA had complied with RCRA and that it would need to provide the Court by December 29, 2013 with a plan including a date for finalizing the CCR rules.

The EPA's proposed rule lays out two very different approaches to regulating CCRs, one as a "solid waste" and the other as a "hazardous waste."

b) Applicability

In 2008 more than 136 million tons of CCRs were produced in the United States.[36] This waste is currently disposed of in various ways. It is placed in approximately 300 CCR landfills or 584 surface impoundments (i.e., ponds[37]) at approximately 495 coal-fired power plants across the nation. It is also placed in mines. CCRs can also be "beneficially" used, for example, as raw materials in the production of Portland cement, wallboard, and other building materials.[38]

c) Compliance Options

As noted, the EPA has proposed alternative approaches for regulating the disposal of CCRs as can be seen in Table 2, one under Subtitle C and the other under Subtitle D of the RCRA.[39] The CCR rule also articulates several additional alternatives to the Subtitle C or D approaches.[40]

The more stringent Subtitle C approach would treat CCRs as a hazardous waste. For example, under this approach parties who create, transport, or store CCRs would be subject to various requirements including permitting, groundwater monitoring, and financial assurance. Existing landfills would be required to install groundwater monitoring within one year of the effective date of the rule. If monitoring were to show groundwater contamination, remedial action would be required. New or expanded landfills would be required to install composite liners and groundwater monitoring before the landfill begins operation.

Under a less-stringent approach set out under Subtitle D, CCRs would continue to be classified by the EPA as a "non-hazardous" waste. Facilities would be subject to national minimum criteria governing CCR disposal. Subtitle D engineering requirements (e.g., liners and groundwater monitoring) would be similar to Subtitle C.

Under certain circumstances, CCRs can be used as a constituent in building materials. This exemption is known as the Bevill exemption and would remain in place under either proposed approach, Subtitle C or D.[41]

As discussed in the following section, the EPA is considering the potential for coordinating compliance under the ELG rule and compliance under the proposed CCR rule.

34 *Appalachian Voices v. EPA,* 2012.

35 *Appalachian Voices v. EPA,* 2013.

36 ICF International, 2013 at page 9. According to ICF International, the current distribution of disposal methods is as follows: 21 percent surface impoundments (wet); 36 percent landfills (dry or moist); 5 percent mines; and 38 percent recycled. See Fine, 2011 at slide 21.

37 The EPA indicates that 75 percent of impoundments are greater than 25 years old and 10 percent are greater than 50 years old.

38 According to the EPA, "[b]eneficial use refers to use of material that provides a functional benefit – that is, where the use replaces the use of an alternative material or conserves natural resources that would otherwise be obtained through extraction or other processes to obtain virgin materials." See U.S. EPA, 2013e.

39 The EPA derives its authority over solid waste disposal from the RCRA, 42 U.S.C.A. §§ 690 et seq.

40 The EPA is also considering additional alternatives to the Subtitle C or D approaches. See Appendix A to this document.

41 In 1980, RCRA was amended to add a provision known as the Bevill exclusion, to exclude "solid waste from the extraction, beneficiation, and processing of ores and minerals" from regulation as hazardous waste under Subtitle C of RCRA. Id. U.S.EPA, 2012h, discussing RCRA Section 3001(b)(3)(A)(ii).

Table 2

Key Differences Between Subtitles C and D[42]

	Subtitle C	Subtitle D
Effective Date	Timing will vary from state to state, as each state must adopt the rule individually—can take 1-2 years or more	Six months after final rule is promulgated for most provisions.
Enforcement	State and Federal enforcement	Enforcement through citizen suits; states can act as citizens.
Corrective Action	Monitored by authorized States and EPA	Self-implementing
Financial Assurance	Yes	Considering subsequent rule using CERCLA 108 (b) Authority
Permit Issuance	Federal requirement for permit issuance by states (or EPA)	No
Requirements for Storage, Including Containers, Tanks, and Containment Buildings	Yes	No
Surface Impoundments Built Before Rule is Finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date. Would effectively phase out use of existing surface impoundments.	Must remove solids and retrofit with a composite liner or cease receiving CCRs within five years of effective date and close the unit
Surface Impoundments Built After Rule is Finalized	Must meet Land Disposal Restrictions and liner requirements. Would effectively phase out use of new surface impoundments.	Must install composite liners. No Land Disposal Restrictions
Landfills Built Before Rule is Finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring
Landfills Built After Rule is Finalized	Liner requirements and groundwater monitoring	Liner requirements and groundwater monitoring
Requirements for Closure and Post-Closure Care	Yes; monitored by states and EPA	Yes; self-implementing

4. Potential Overlap Between the ELG and CCR Rules

In the ELG, the EPA discusses the CCR rulemaking to better understand "the analyses underlying these proposed revisions to the steam electric generating ELGs," and further to consider where the CCR rule "might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category."[43] The EPA also sets out what it refers to as its "current thinking" on how it might issue a final CCR rule that would allow compliance entities to account for relevant final effects on CCR rule compliance of the final ELG for electric generators.[44]

Although the EPA needs to be able to ensure the

42 In its May 2010 pre-published version of the proposed rule, the EPA indicated that it "has not projected a date for a final rule at this time." Discussion of the EPA's proposed CCR rule based on Devlin, 2010.

43 Effluent Limitations Guidelines, 2013.

44 The EPA notes that in the ELG notice it is not making any proposals with regard to CCRs that are different from those made in its proposed rule of June 21, 2010. It is thus not taking further public comments on the rule. The EPA also notes that this effort is consistent with RCRA section 1006(b), a provision directing the EPA to integrate the provisions of RCRA for purposes of administration and enforcement and to avoid duplication, to the maximum extent practicable, with the appropriate provisions of the Clean Air Act and other federal statutes. This integration must be done in a way that is consistent with the goals and policies of these statutes. RCRA section 1006(b) authorizes deferral of RCRA provisions to other EPA-implemented authorities provided, among other things, that key RCRA policies and protections are not abandoned.

attainment of its statutory responsibilities to restore and maintain water quality under the CWA and to protect human health and the environment under RCRA, the EPA is considering two approaches to integrating the two rules through coordinating the:

- Design of any final substantive CCR regulatory requirements, and
- Timing and implementation of both rules.[45]

a) Rule Design

The EPA recognizes that despite the different focus of the two rules, they both would affect the disposal of CCRs to and from surface impoundments at power plants. The EPA further notes that the ELG rule could reduce or entirely eliminate discharges to surface water, including the control or elimination of wastewater being sent to and discharged from surface impoundments.[46]

Another significant development in the proposed ELG is the EPA's acknowledgement that new data and information have become available that could affect the EPA's determination of the nature and extent of the risk of CCR disposal. The new data provide support for a conclusion that CCR disposal could be regulated under RCRA Subtitle D as nonhazardous waste rather than under RCRA Subtitle C as a hazardous waste.

b) Coordinating Rule Timing and Implementation

The EPA has also indicated its interest in coordinating the ELG implementation schedule for existing sources with the EPA's planned promulgation of the final CCR disposal rule. Both rules are now expected to be finalized in mid-2014.[47] The EPA's goal is that, consistent with its statutory requirements, the implementation dates for each rule would not require facilities to make decisions without understanding the implications that such decisions would have for meeting any requirements of each rule.

The EPA recognizes that the requirements that the regulation would impose on existing sources would not apply until sometime after July 1, 2017, approximately three years from the proposed effective date of the rule. Because these standards would be implemented as part of an NPDES water permit revision, typically a five-year cycle and a process in which states have discretion in their reissuance of permits,[48] the provisions of the proposed regulation would actually apply to discharges of FGD wastewater generated on or after the date established by the permitting authority, that is, as soon as possible within the next permit cycle after July 1, 2017.[49] The EPA estimates that this could mean that all steam electric facilities will have the limitations from this rule applied in permits no later than July, 2022, approximately eight years from the date of promulgation of any final rule.[50]

c) Recommendations

The EPA's proposed CCR regulations contain the potential for compliance flexibility. The EPA has indicated the possibility that it would proceed and develop the regulation under Subtitle D, which would result in characterizing CCRs as solid waste rather than hazardous waste. This would result in less stringent oversight. The EPA is also expected to preserve the "beneficial use" exception, which would permit the use of CCRs in building materials. With the recent *Appalachian Voices, et al* decision, the EPA is on a quick timeline for proposing a rule that will, in turn, result in the need for quick responses from compliance entities.

Energy regulators should engage state solid waste regulators and the utility companies themselves to determine company preparedness for compliance with the rule. With their help, energy regulators could determine the amount of generation capacity that will be affected, and a reasonable range of potential compliance costs. In restructured jurisdictions, state regulators could get this information by engaging system operators, and generation-owners and operators directly.

45 Effluent Limitations Guidelines, 2013.

46 The EPA notes that one of the potential results of the ELG is that certain facilities could choose to modify "their sluicing operations to dry ash-handling systems, and will no longer send such wastes to surface impoundments." Effluent Limitations Guidelines, 2013.

47 Effluent Limitations Guidelines, 2013. This conclusion is subject to a report the EPA has been ordered to submit to the District Court for the District of Columbia. *Appalachian Voices v. EPA,* 2012.

48 State permitting authorities can take into consideration the need for additional time to include best available technology limits to avoid or minimize the potential for forced outages. Effluent Limitations Guidelines, 2013.

49 Effluent Limitations Guidelines, 2013.

50 The EPA notes that this timeline could be different for indirect dischargers. In their case, relevant pretreatment standards, with the exception of discharges of nonchemical metal cleaning waste, could apply by the date determined by the control authority, that is, as soon as possible beginning July 1, 2017. Effluent Limitations Guidelines, 2013.

With regard to the potential for the EPA to coordinate the ELG and CCR rules, energy regulators could query state solid waste regulators, utility companies, and, where relevant, generators and system operators, to determine the most reasonable means of coordinating the ELG and CCR rules and likely outcomes for the generation sector. States could use this information in their discussions with the EPA as they explore greater efficiencies, both compliance-related and administrative. This could translate into lower program costs to compliance entities, and ultimately utility ratepayers. In reviewing utility compliance planning, regulators could encourage utilities to take advantage of both the opportunity to comment and — assuming the proposed provisions are adopted — the opportunity to exploit potential benefits of coordination between the two rules.

B. Air Regulations

1. National Ambient Air Quality Standards

The EPA has developed standards and regulations under its Clean Air Act authority. These focus on NAAQS (pronounced "knacks"), the CSAPR, the Mercury Air Toxics Rule, and various rules related to GHG, including NSPS for carbon dioxide.

a) Setting NAAQS

Since it was created in 1970, the EPA has overseen significant improvements in the quality of the nation's air resources. The Clean Air Act directed the EPA to set NAAQS for a limited set of what are called "criteria" pollutants: carbon monoxide, ground-level ozone, lead, NO_2, particulates,[51] and SO_2.

The Act established two types of standards for criteria pollutants:

- Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatic individuals, children, and elderly people. Cost-benefit calculations are not considered in setting these standards; and
- Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. Cost-benefit calculations are part of setting these standards.

Table 3

Effects of Air Pollutants on Human Health, Environment, and Climate[52]

Pollutant	Health Effects	Environmental Effects	Climate Effects
Particulate matter (PM)	Cardiovascular and lung disease, central nervous system and reproductive system effects, cancer, and premature death	Same effects on animals as humans, affects plant growth and ecosystem processes, damages buildings, reduces visibility	Varies depending on particle size and composition: some lead to net cooling; others lead to warming; can modify rainfall patterns and surface albedo
Ozone (O_3)	Asthma and other lung disease, decreased lung function, and premature death	Damages plant reproduction and growth, decreases crop yields, reduces biodiversity, decreases plant uptake of CO_2	Contributes to warming
Nitrogen Oxides (NO_X)	Liver, lung, spleen and blood effects; lung diseases and infection susceptibility	Precursor of O_3 and PM, increases acidification and eutrophication of soil and water, changes species diversity, damages buildings	Contributes to the formation of O_3 and PM and their climate effects
Sulfur Oxides (SO_X)	Asthma, reduced lung function, respiratory tract inflammation, headache, general discomfort, and anxiety	Precursor of PM, increases acidification and eutrophication of soil and water, damages vegetation, reduces species diversity, damages buildings	Contributes to the formation of sulfate particles, cooling the atmosphere
Carbon monoxide (CO)	Heart disease, nervous system damage, headaches, dizziness, and fatigue	Same effects on animals as humans	Contributes to the formation of GHGs such as CO_2 and O_3

51 The EPA sets standards for two categories of particle pollution. Fine particles, also known as $PM_{2.5}$, are 2.5 micrometers in diameter and smaller. Inhalable coarse particles, known as PM_{10}, are smaller than 10 micrometers. (A micrometer is 1/1000 of a millimeter, and there are 25,400 micrometers in an inch.)

52 Based on European Environment Agency, 2012.

The Clean Air Act gives the EPA three years to issue designations after promulgating a NAAQS. The EPA is required under the Act to re-examine the standards once every five years.[53] The Act also requires periodic review of the science upon which the standards are based.

Human health effects of exposure to criteria pollutants include cardiovascular and lung disease (particulate matter), asthma and other lung disease (ozone), lung diseases (NOx), asthma (SO_2), and heart disease (CO) (Table 3).

b) Progress on Criteria Pollutants and Health-Based Emissions Levels

The EPA has reported significant reductions in the emissions of many of these criteria pollutants.[54] Nationally, air emissions were lower in 2010 than in 1990 for:

- Eight-hour ozone (17 percent)
- 24-hour PM_{10} (38 percent)
- 3-month average lead (Pb) (83 percent)
- Annual NO_2 (45 percent)
- Eight-hour CO (73 percent)
- Annual SO_2 (75 percent)

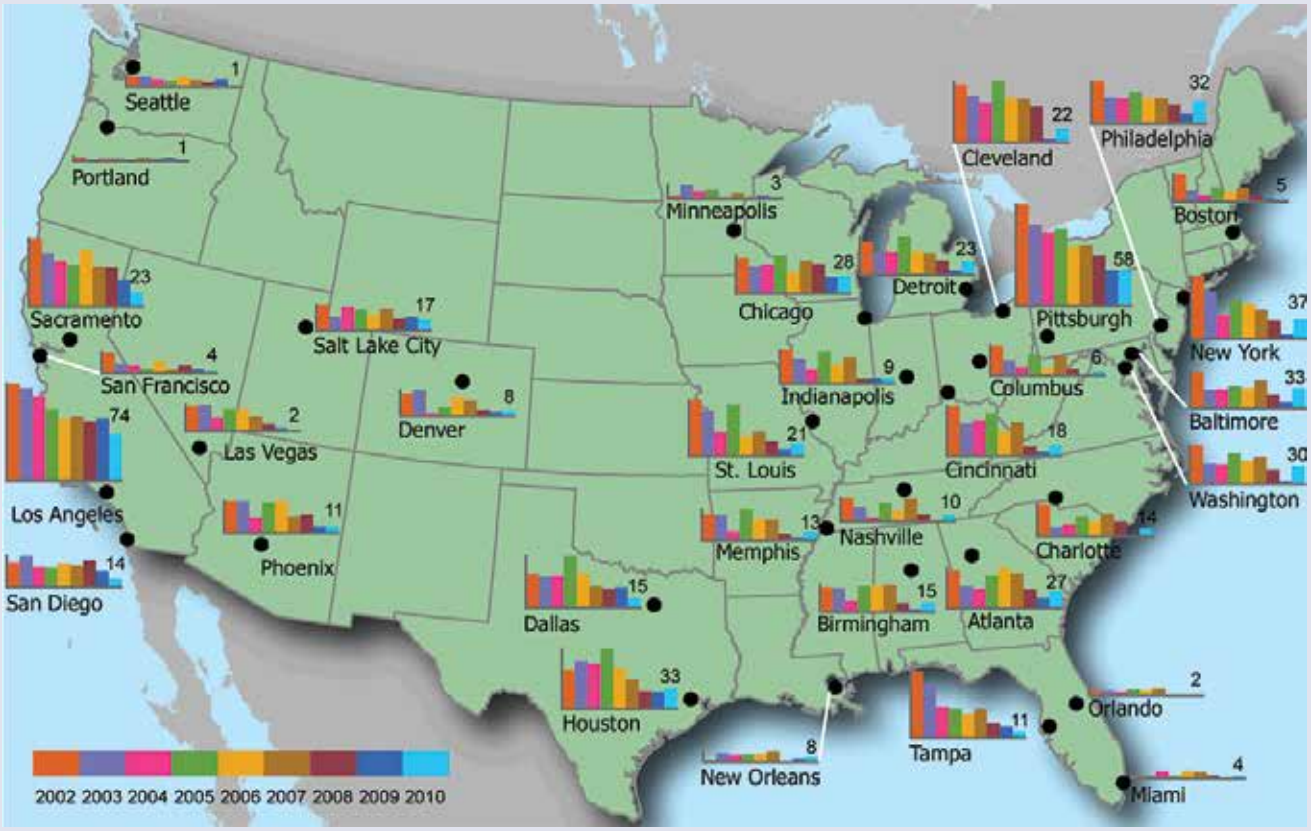
The EPA also reports $PM_{2.5}$ concentrations down since 2001. Annual $PM_{2.5}$ concentrations were 24 percent lower, and 24-hour concentrations were 28 percent lower.

c) More to Be Done

Even with this progress, the EPA data show that nearly half of the nation's population (149 out of 315 million) live in counties that exceed one or more NAAQS in 2010.[55] The EPA has developed an Air Quality Index (AQI) that connects daily concentrations of air pollution for ozone, particle

Figure 2

Days on Which AQI Values Were Greater Than 100 During 2002 to 2010 in Selected Cities[56]



53 See e.g., *Sierra Club v. EPA*, 2013 where Sierra Club claims that the EPA is violating a Clean Air Act mandate to review its NAAQS every five years, as the ozone limit was last reviewed in a March 27, 2008 final rule.

54 U.S. EPA, 2012b.

55 U.S. EPA, 2013j.

56 The city designations include larger areas, that is, Los Angeles-Long Beach-Santa Ana, CA; Houston-Sugar Land-Baytown, TX; and Chicago-Naperville-Joliet, IL-IN-WI. The data behind this graphic can be found at U.S. EPA, 2012c.

pollution, NO_2, CO, and SO_2 to health risks for sensitive groups and for the general public. An AQI value of 100 roughly corresponds to the health-based standard (NAAQS) for each pollutant. AQI values below 100 are considered satisfactory, whereas values above 100 are considered unhealthy, first for certain sensitive groups of people and then, as the values increase, for the general public.

For example, in 2010 AQI values were unhealthy for a large number of days in Los Angeles (74), Pittsburgh (58), New York (37), Houston (33), Washington (30), Chicago (28), and Atlanta (27).[57]

NAAQS do not impose direct compliance requirements on electricity generators. Instead, these standards apply to states, and states must find ways to ensure that their air quality does not fall below these standards.[58] Plans for addressing these air quality requirements are known as SIPs. In areas where air quality does not meet NAAQS, state or local regulators must develop SIPs, subject to EPA approval, to meet the standards.

Although not always, SIPs in this context can reflect new regulatory requirements on electric generators. Generally, generators in nonattainment areas have historically faced regulatory requirements that are more stringent and costly than those in areas that meet the NAAQS. A nonattainment designation can also result in significant financial repercussions for states and other emitters, including loss of federal highway funding, increased motor fuel costs owing to fuel reformulation requirements, enhanced regulatory oversight (e.g., permitting requirements), economic development sanctions (e.g., mandatory emissions offsets), and reputation damage.

d) Current NAAQS – SO_2

Regulators should be aware that on December 6, 2013, U.S. District Court for the Northern District of California granted a request for summary judgment in a lawsuit seeking to force the EPA to meet attainment and nonattainment deadlines for its 2010 SO_2 NAAQS.[59] With that order, the case will proceed to the remedy phase, forcing the EPA to make the required designations.[60]

e) New NAAQS – Particulates and Ozone

In the next year, states can expect to be faced with the implementation of new standards for particulate matter and a new proposal for ozone. On January 15, 2013, the EPA published a final rule revising the NAAQS for particulate matter. The new annual standard for $PM_{2.5}$ was lowered from 15 micrograms per cubic meter (µg/m3) to a limit of 12 µg/m3. The EPA kept in place the existing 24-hour $PM_{2.5}$ standard at 35 µg/m3. The EPA also kept its existing standards for PM_{10}.[61]

The EPA's revision does not result in direct changes to emissions regulations from any specific emissions sources, nor does it directly require the installation of any pollution control equipment or measures, however, it could indirectly affect the operation of various sources of particulate emissions through eventual permit modifications.

As noted previously, part of the NAAQS modification process includes an identification of areas in each state that exceed the standard and would thus be required to reduce concentrations of that pollutant to meet the new standard. If an area is determined to be in "nonattainment," as mentioned earlier, state and local governments must modify their SIPs and set out measures that will result in their meeting the new standard.[62] According to the Congressional Research Service,

> *Based on statutory scheduling requirements, nonattainment designations for revised PM NAAQS would not be determined until the end of 2014, and states would have until at least 2020 to achieve compliance with the January 2013 revised $PM_{2.5}$ NAAQS.*[63]

57 U.S. EPA, 2012c.

58 See, e.g., footnote 80 and accompanying discussion of Clean Air Act Section 110.

59 *Sierra Club et al v. EPA,* 2013. See also Inside EPA, December 11, 2013. The plaintiffs sought enforcement of the one-hour (75 ppb) SO_2 standard.

60 Id.

61 U.S. EPA, 2012a.

62 Where states fail to meet minimum Clean Air Act requirements in their SIPs, the EPA can step in and develop a Federal Implementation Plan for the state. See e.g., *Oklahoma v. EPA,* 2013. In a case in which the State of Oklahoma, the Oklahoma Gas and Electric Company, among others, challenged a final rule promulgated by the EPA under the Clean Air Act, the U.S. Court of Appeals for the 10th Circuit found in favor of the EPA where petitioners argued that the EPA impermissibly rejected Oklahoma's plan to limit the emissions of SO_2 at Oklahoma Gas and Electric Company power plants and replaced it with its own more stringent regulations, which petitioners contend usurped the state's authority and will require sizable expenditures on unnecessary technology. The court concluded that the EPA has authority to review the state's plan and that it lawfully exercised that authority in rejecting it and promulgating its own.

63 Esworthy, 2013.

Preliminary EPA estimates have projected that 66 counties won't meet the new $PM_{2.5}$ standard.[64] In addition to developing a new $PM_{2.5}$ NAAQS, the EPA has indicated its intent to propose new ozone standards in December 2013 and finalize them in 2014. Environmental and health NGOs sued the EPA for missing the statutory five-year deadline for reviewing the ozone air quality standards, and sought a court-ordered deadline.[65] Once proposed, the EPA will have a year to finalize these rules, and should follow a process similar to that described earlier for the $PM_{2.5}$ NAAQS.

For ozone, the EPA did an analysis in 2010 using monitoring data from 2006 to 2008.[66] Those data showed 322 counties violating the existing 75 parts per billion (ppb) standard.[67] If the EPA were to set a standard within a more stringent range of concentrations (60–70 ppb), levels previously recommended by the EPA's Science Advisory Board, there would be even greater incidences of nonattainment:

- 515 counties at 70 ppb;
- 608 counties at 65 ppb; and
- 650 counties at 60 ppb.[68]

f) Recommendations

Utility regulators should engage with their counterparts in air agencies to maintain an understanding of any potential effects from existing and changing NAAQS on their state. Energy regulators should also keep apprised of any potential effects on states from which jurisdictional utilities purchase power.

2. The Cross-State Air Pollution Rule Schedule

- Final Rule, July 6, 2011
- U.S. Court of Appeals for the D.C. Circuit stays rule, December 30, 2011 (Clean Air Interstate Rule "CAIR" overturned by D.C. Circuit in 2008 remains in effect)
- The D.C. Circuit decides *EME Homer City Generation v. EPA,* vacating the CSAPR rule, August 21, 2012
- EPA petitions for *en banc* rehearing, October 5, 2012
- D.C. Circuit denies EPA's petition for rehearing, January 24, 2013
- U.S. Solicitor General petitions the Supreme Court to review the D.C. Circuit Court's decision on CSAPR, March 29, 2013
- Supreme Court agrees to review of D.C. Circuit's decision, June 24, 2013
- *GenOn REMA LLC v. EPA,* decided by the U.S. Court of Appeals for the Third Circuit, ruling that the Clean Air Act does not foreclose the EPA from forcing upwind states to address pollution that significantly contributes to a downwind state's nonattainment
- Supreme Court oral argument set in *EME Homer City,* for December 10, 2013
- Clean Air Interstate Rule remains in effect pending outcome of Supreme Court review

a) Background

The CSAPR was issued in July 2011 and vacated by the D.C. Circuit in August 2012 in *EME Homer City Generation v. EPA.*[69] The Supreme Court is currently reviewing that decision. CSAPR was supposed to replace the Clean Air Interstate Rule (CAIR) that was also overturned by the D.C. Circuit in 2008 because CAIR did not adequately protect downwind states. CAIR stays in place pending a legal determination on CSAPR.

CSAPR's goal is the reduction of long-range transport of power plant emissions of SO_2 and NOx. Pollution transported from upwind states contributes to the inability of downwind states to meet primary NAAQS for $PM_{2.5}$ and ozone.

64 This, they note, is based on preliminary data, meaning some of the areas may not be designated as nonattainment. See EPA Map http://www.epa.gov/pm/2012/20092011map.pdf, based on "2009–2011 air quality data as of July 15, 2012." Id. See also www.epa.gov/pm.

65 *Sierra Club v. EPA,* 2013.

66 U.S. EPA, 2010a.

67 See page 1 map. Id.

68 See page 2 map. Id.

69 *EME Homer City Generation, L.P. v. EPA,* 696 F.3d 7 (D.C. Cir. 2012), *reh'g and reh'g en banc denied,* No. 11-1302 (D.C. Cir. January 24, 2013). The court determined that the EPA overstepped its authority by making upwind states reduce emissions beyond their own contributions to downwind states' inability to meet relevant emissions standards. The court also concluded that the EPA should have given states an initial chance to implement required emissions reductions on their own (through SIP modifications) rather than imposing a federal implementation plan.

b) Applicability

CSAPR is intended to address interstate transport of pollutants emitted by electric generators located in the eastern two-thirds of the country, by reducing annual SO_2 and NOX emissions to help downwind areas meet ambient air quality standards for particulates and ozone.

Regardless of the outcome of the Homer City appeal, it is reasonable to expect that generators will continue to be subject to some obligation with respect to transported air pollution in the CAIR/CSAPR regions, and potentially subject to compliance actions owing to possible effects on neighboring states.

c) Compliance Options

Despite CSAPR's status, air pollution continues to be transported across state lines by prevailing winds.[70] And the Clean Air Act continues to require the EPA to take action to address it, whether under Section 110 (SIPs)[71] or other provisions of the Act that impose responsibilities on states whose emissions are found to contribute substantially to a downwind state's noncompliance with the law.[72]

On July 12, 2013, in a case unrelated to CSAPR, the U.S. Court of Appeals for the Third Circuit in *GenOn REMA, LLC v. EPA,* ruled that the Clean Air Act does not foreclose the EPA from forcing upwind states to address air pollution that significantly contributes to a downwind state's nonattainment of health-based NAAQS.[73] The *GenOn* court upheld a rule that imposed emissions limits and compliance schedules on an individual coal-fired power plant in Pennsylvania. The EPA had promulgated the rule in response to a petition filed by the State of New Jersey under Clean Air Act Section 126(b), which argued that emissions from the Pennsylvania plant were significantly contributing to the inability of several counties in New Jersey to meet relevant air quality standards.[74]

The court in this decision distinguished the process set out in Section 126 of the Clean Air Act with the "SIP call" process set out in Section 110 that is under consideration in *EME Homer City v. EPA.* The Third Circuit disagreed with GenOn's attempt to use the *EME Homer City* case to support its position that the EPA could not act on New Jersey's petition, and instead noted that the *EME Homer City* opinion also provided that Section 126 is "a separate provision [from Section 110] that explicitly contemplates direct EPA regulation of specific sources that generate interstate pollution."[75]

Although CSAPR's fate is uncertain, any *Homer City* decision from the Supreme Court will not entirely eliminate the uncertainty about public health-based air regulations that has vexed public utility commissions, the utilities they regulate, and the investment community for more than a decade.[76] Despite the legal status of both CSAPR and CAIR, the EPA continues to find that SO_2 and NOx emissions produced in over half of the states in the country affect the air quality in neighboring states.[77] Furthermore, the "classic upwind transport tool" – Section 126 Petitions requesting

70 The stay of CSAPR also effectively calls into question an agreement between EPA and certain states allowing CSAPR to be used to meet Regional Haze Rule compliance requirements. U.S. EPA, 2012e. That rule requires power plants to reduce emissions affecting visibility in national parks and wilderness areas. The rule also requires the installation of best available retrofit technology, a less flexible and potentially more expensive alternative to the cap-and-trade compliance allowed for under CSAPR. See, e.g., partial disapproval of Arizona's SIP, U.S. EPA (2012, September 26) Air Actions, Arizona. Available at: http://www.epa.gov/region9/air/actions/az.html.

71 "Section 7410(a)(2)(D)(i), also known as the "good neighbor provision," prohibits sources or emissions activity within a state from emitting air pollutants in amounts that will… contribute significantly to nonattainment in, or interfere with maintenance by, any other State…." *GenOn REMA, LLC v. EPA,* 2013.

72 See e.g., Glass, B. (2013, July 18) "Third Circuit dishes up Section 126(b) Hors D'oeuvre While Everyone Waits to Learn Whether a CSAPR Entree is on the Menu." Warren Glass Law. Available at: http://warrenglasslaw.com/third-circuit-dishes-up-section-126b-hors-douvre-while-everyone-waits-to-learn-whether-a-csapr-entree-is-on-the-menu/.

73 *GenOn REMA, LLC v. EPA,* 2013.

74 The EPA had made a finding that SO_2 emissions from the Pennsylvania facility significantly contribute to the nonattainment of the one-hour SO_2 NAAQS in New Jersey and, on that basis, imposed stringent emissions limits and compliance schedules requiring the facility, on a defined schedule, to reduce its SO_2 emissions by approximately 81 percent within three years.

75 *GenOn REMA, LLC v. EPA,* 2013 at 23. "However, far from helping GenOn and UARG, language in this case actually supports the EPA's construction of the statute. See *EME Homer City Generation, L.P. v. EPA,* 2012. Id.

76 Colburn et al., 2013.

the EPA to require controls on specific (or groups of) stationary sources that contribute to nonattainment in downwind areas – remains available to downwind states unable to meet the requirements of their own SIPs.[78]

Thus, although regulations may be proposed, vacated, reworked, and reproposed, the Clean Air Act will still require the EPA to ensure that states can put into effect their SIPs without significant interference from upwind neighbors.[79] And the Act will continue to direct the EPA to work with all the states to be able to do that.[80]

d) Recommendations

Energy regulators should become familiar with the various options available to generators depending on the outcome of the Supreme Court's review of CSAPR in the *EME Homer City* case. It is not clear whether the lower court decision will be upheld or overturned, whether CSAPR will be reinstated or if and when the EPA would produce a "CSAPR 2.0."

It is important to recognize that individual generators could face some obligation with respect to transported air pollution in the CAIR/CSAPR regions, and face compliance actions owing to effects of their air emissions on neighboring states. It is also reasonable to expect the EPA to continue to develop a programmatic solution to the challenge of transported air pollution.

While CAIR continues in place, energy regulators should keep abreast of potential outcomes of the CSAPR litigation through exchanges with their counterparts in state air offices and with federal air regulators. State energy regulators should also be communicating with utility companies and, in restructured jurisdictions, with system operators and generators themselves.

3. Mercury/Air Toxics Rule

The MATS Rule Schedule

- Proposed May 3, 2011
- Finalized December 16, 2011
- *White Stallion Energy Center, LLC v. EPA,* rule challenged in the D.C. Circuit, February, 2012
- Effective date April 16, 2012
- Unit compliance date April 16, 2015 (three years from effective date)
  - (Case-by-case one-year extension, additional one-year extension via enforcement order for "reliability-critical" units)
- Reconsideration of standards for new power plants July 20, 2012
- Proposed rule with updated standards for new power plants November 30, 2012
- Final Rule published April 24, 2013

a) Background

In December 2011, the EPA finalized the Mercury and Air Toxics Standards (MATS, or Rule) for Power Plants, a rule it had proposed pursuant to a consent decree in May of 2011.[81] The rule was published in the Federal Register on February 16, 2012, and establishes the first national standard to reduce mercury and other air toxins from power plants by setting performance standards for mercury and other toxic heavy metals, acid gases, and certain toxic organic compounds.[82]

The U.S. Court of Appeals for the District of Columbia Circuit is currently considering challenges to the MATS rule in *White Stallion Energy Center v. EPA*.[83] Unlike the CSAPR review in *EME Homer City,* in *White Stallion,* no stay has been issued, thus leaving compliance requirements in force.

77 CAIR sought to reduce SO_2 and NOx emissions in 28 eastern states. CSAPR required 23 states in the eastern half of the country to substantially reduce annual SO_2 and NOx emissions, and 25 states to reduce ozone season NOx emissions. Beasley & Morris 2012, at p 2.

78 This term was used by Tad Aburn, Air Director for the State of Maryland. Aburn, 2011.

79 See Clean Air Act, Section 110.

80 Sections 110(a)(1), (a)(2), and (c)(1) of the Clean Air Act require each state to adopt and then submit a SIP to the EPA within three years after the development of a primary NAAQS or a revision of a NAAQS. Each SIP is required by the statute to contain adequate provisions fulfilling its good neighbor obligations. If the EPA finds that the SIP is insufficient, then the EPA is required to develop, in its place, a Federal Implementation Plan.

81 Section 112(d) of the Clean Air Act, enacted as part of the 1990 Clean Air Act Amendments, directs the EPA to set National Emission Standards for hazardous air pollutants for each category of sources listed by the Act.

82 National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units, 2012.

83 More than 30 challenges to the MATS rule have been consolidated in *White Stallion Energy Center, LLC v. EPA,* 2012.

Following publication of the final rule, the EPA received requests for reconsideration. On July 20, 2012 the EPA indicated that it would grant reconsideration of certain issues. On November 16, 2012, the EPA issued updated emissions limits for new power plants, and finalized those updates for new power plants on March 29, 2013.[84] The EPA set less stringent limits on certain pollutants owing to new information and analysis that it received during the reconsideration period.[85]

Power plants are responsible for half of the nation's mercury emissions and half of the acid gases. In preparation for proposing the MATS rule, the EPA estimated that there are approximately 1350 coal- and oil-fired units at 525 power plants that would be subject to this rule. Pollutant emissions that the rule covers include mercury, arsenic, other toxic metals, acid gases, and organic air toxics such as dioxin.

Human health effects of exposure to these pollutants include neurologic developmental effects (mercury), inflammation and neurotoxicity (cadmium, manganese, and lead), acute inflammation and irritation (acid gases like hydrogen chloride and hydrogen fluoride), and potential cancer risks (dioxins)[86] (Table 4).

Section 112 of the Clean Air Act contains standards for both existing and new sources. The Section 112 standard for existing sources states that Maximum Achievable Control Technology (MACT) "shall not be less stringent, and may be

Table 4

Effects of Air Pollutants on Human Health, Environment, and Climate[87]

Pollutant	Health Effects	Environmental Effects	Climate Effects
Arsenic (As)	Cancer, damage to blood, heart, liver, and kidney; may also damage the peripheral nervous system	Highly toxic to wildlife, reduces plant growth and crop yields, persists and bioaccumulates	No specific effects
Cadmium (Cd)	Likely carcinogenic, may damage reproductive and respiratory systems.	Toxic to aquatic life, persists and bioaccumulates	No specific effects
Lead (Pb)	Affects almost every organ and system, premature birth, impairs mental development and growth	Reproductive problems, adverse impacts on terrestrial and aquatic systems, persists and bioaccumulates	No specific effects
Mercury (Hg)	Damages liver, kidneys, digestive, and respiratory systems, brain and neurological damage, and impairs growth	Very toxic to wildlife, persists and bioaccumulates	No specific effects
Nickel (Ni)	Cancer, skin allergies, affects respiratory, immune, and defense systems	Same effects on animals as humans, toxic to aquatic life	No specific effects
Benzene (C_6H_6)	Cancer, leukemia and birth defects, affects central nervous system, blood, and immune system	Damages crops, reproductive systems, toxic to aquatic life, bioaccumulates	Benzene is a GHG contributing to the warming of the atmosphere. It also contributes to the formation of O_3 and secondary organic aerosols, which can act as climate forcers
Benzo-a-pyrene (BaP)	Cancer, irritates eyes, nose, throat, and bronchial tubes	Toxic to aquatic life and birds, bioaccumulates	No specific effects

84 Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 2013.

85 The EPA revised limits on (1) hydrogen chloride; (2) filterable particulate matter; (3) SO_2; (4) lead; and (5) selenium. The EPA indicated that the revisions should not alter the control technologies that owners and operators must install to comply with MATS. The rule requires new plants to comply with these standards when the revised final rule is published in the Federal Register, or upon plant startup.

86 See e.g., Greenbaum, 2010. See also, e.g., Clean Air Task Force, 2010.

87 Table based on European Environment Agency, 2012.

more stringent than the average emission limitation achieved by the best performing 12 percent of the existing sources… in the category or subcategory…." Section 112 states that the standard for "new" sources "shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator." The MATS rule sets standards based on the best-performing 12 percent of coal- and oil-fired electric generators with a capacity of ≥25 MW for all hazardous air pollutants (HAPs) emitted.

b) Applicability

MATS applies to electric generating units larger than 25 MW that burn coal or oil to generate power for sale and distribution through the national electric grid. It does not apply to power plants burning natural gas because gas plants are not a significant source of HAP emissions. The rule will require affected power plants to limit their emissions of toxic pollutants, including 90 percent of their mercury emissions that would otherwise result from combusting coal.

The rule also sets numeric emissions limits for particulate matter that will serve as a surrogate for all of the toxic metals other than mercury, and for hydrochloric acid, a surrogate for toxic acid gases.[88]

In order to limit the emission of organic air toxics like dioxin, power plants will also be subject to work practices standards. This approach requires power plant compliance with annual performance test programs for each unit, including inspection, adjustment, and/or maintenance and repairs to ensure optimal combustion.

Flexibility

MATS is "one of EPA's largest regulations to date in terms of cost and impact, [and has] resulted in relatively modest expenses for power plants connected by Eastern grid operator PJM, said Craig Glazer, vice president of federal government policy at the regional transmission organization."[89] One of the cost-reducing aspects of MATS is the rule's flexibility provisions. Several are discussed below.

MATS allows for facility-wide averaging. This enables facilities to average the emissions from individual emissions units within the same category. For example, where a facility has two electric generating units emitting mercury, the emissions from both units can be averaged across the facility, in effect treating the facility as though it were one emissions source. The rule also allows for the averaging of a facility's emissions over a 30-day period to accommodate a generating unit's operational variability.

MATS also provides for the use of "surrogates" in regulating emissions. Section 112 of the Clean Air Act lists 188 separate toxic air pollutants. Instead of imposing separate compliance requirements for each one that a generation source emits, the rule allows for the control of one pollutant to stand as a "surrogate" for the control of others. For example, controls for emissions of particulate matter can meet the requirements for controlling emissions of non-mercury metals like arsenic, nickel, and chromium. The EPA allows this because non-mercury metals are emitted along with particulates in flue gas.

c) Compliance Timelines

The Clean Air Act and the EPA provide regulated entities some flexibility with regard to compliance timing under this rule. MATS provides for a three-year compliance period for existing sources, with a deadline of April 16, 2015, but also authorizes state permitting authorities to award entities an extra year for additional time to comply.[90] Furthermore, the EPA has adopted an "enforcement policy" that would allow compliance entities to make a case that they are "reliability critical" and thus deserve an additional (fifth) year to comply with the rule.

There have already been a number of requests for fourth-year extensions. The National Association of Clean Air Agencies (NACAA) recently conducted a survey to determine (1) the degree to which compliance entities are requesting these extensions from state authorities, and (2) the progress with which they are granted.[91] On the basis of responses received by NACAA as of the end of June 2013, it determined that there had been 51 requests, 48 of which had already been granted.[92] None had been refused.[93]

There have been no instances of companies seeking a

88 See discussion of "surrogates" below.

89 Stecker, 2013.

90 National Emission Standards for Hazardous Air Pollutants for Source Categories, 2002, Subpart UUUU.

91 National Association of Clean Air Agencies, 2013.

92 Forty-one agencies in 31 states, D.C., and Puerto Rico responded. According to the responses, there have been 51 extension requests, of which 48 have been granted so far (one is still under consideration, one was retracted by the company, and one was returned to the facility for additional information) and none has been refused to date. The respondents indicated that approximately four more requests may be forthcoming.

93 Id.

fifth year compliance extension. Because this extra time is available only within the context of an enforcement action — a step carrying with it a very negative connotation for a company — the EPA is not likely to see any such requests for several years, if at all.[94]

d) Recommendations

Energy regulators can stay abreast of the news of MATS implementation by working with their counterparts in state air offices. In traditionally regulated jurisdictions, regulators will be able to inquire of utility companies as to their plans and progress in meeting MATS requirements, any undue challenges in those efforts (including challenges related to cost), and the likelihood of the company requesting an extension from the EPA to meet compliance obligations. In restructured jurisdictions, the independent system operators should be a good source of information as to the implementation progress that generators are making in their regions. National organizations like NARUC and NACAA are also keeping track of the status of MATS implementation and would be a good source of information for state regulators.

4. Clean Air Act and Greenhouse Gases

The EPA's direct regulation of GHG to date can be understood by considering four separate administrative actions and rules.[95] The first three are briefly described below, while NSPS are discussed in more detail:

1. GHG Reporting Rule
2. Endangerment Finding/Light Duty Vehicle (Tailpipe) Rule
3. Johnson Reconsideration, Tailoring, and Timing Rules
4. NSPS for New and Existing Sources of CO_2

a) GHG Reporting Rule

The EPA signed the final rule for reporting GHG on November 8, 2010. Operators of facilities that emit 25,000 metric tons or more of GHG per year are required to quantify and report emissions annually pursuant to 40 CFR Part 98.[96] For example, existing coal plants emit approximately one ton of CO_2 per MWh and gas plants approximately 0.5 ton per MWh, so 25,000 MWh of generation per year from a coal plant or 50,000 MWh from a gas plant would trigger the need to quantify and report GHG emissions. CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP).[97] Because power plants were already subject to reporting of other air pollutants, the incremental costs of reporting GHG emissions are generally very small and utility regulators should not need to take any specific actions to prepare for this requirement.

b) Endangerment Finding/Light Duty Vehicle Rule

The EPA is obligated to regulate CO_2 emissions pursuant to the federal Clean Air Act and consistent with the 2007 Supreme Court decision in *Massachusetts v. EPA*.[98] In response to that decision, the EPA issued an Endangerment Finding in December 2009 stating that, "greenhouse gases in the atmosphere endanger the public health and welfare of current and future generations."[99] The EPA also found in December 2010 that motor vehicle emissions contribute to the GHG air pollution that endangers public health and welfare, and subsequently issued the Light Duty Vehicle Rule, also referred to as the Tailpipe Rule, that was finalized on May 7, 2010.[100] These rules in turn triggered regulation of stationary sources.

The question of whether the EPA has the authority to regulate GHG is settled. For example, in 2011 the Supreme

94 It is hard to imagine a company willing to risk its reputation in an enforcement action to take advantage of a fifth year of compliance flexibility.

95 While not directly regulating CO_2 or methane emissions from the oil and gas sector, the EPA regulates that sector's emissions of volatile organic compounds (VOCs) under NSPS Subpart OOOO. VOCs are a large group of carbon-based compounds that easily evaporate at room temperature. The EPA has determined that there is collateral emissions reduction of methane owing to VOC emissions controls or CO_2 reduction. The EPA considers the co-benefits of methane reductions in this context when assessing cost/benefits. Ramamurthy, 2013.

96 Mandatory Greenhouse Gas Reporting, 2013. See Discussion of global warming potential in Appendix One – Risk and Natural Gas.

97 U.S. EPA, 2011. The EPA notes that because "GWP values may vary, applicants should use the GWP values in Table A-1 of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A, Table A-1)." Id.

98 In *Massachusetts v. EPA* the Supreme Court found that GHG emissions are "air pollutants" under the Clean Air Act. The Court required the EPA to determine whether or not emissions of GHG from new motor vehicles cause or contribute to air pollution reasonably anticipated to endanger public health or welfare, and this requires the EPA to respond to petitions for rulemaking requesting the EPA to regulate CO_2 and other GHG from motor vehicles. *Massachusetts v. EPA*, 2007.

99 Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 2009.

100 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, 2010.

Court, in *American Electric Power Co. v. Connecticut,* ruled that the Clean Air Act and the EPA's implementation of the Act override any federal common-law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants.[101] In October 2013, the Supreme Court declined to hear challenges to the EPA's Endangerment Finding or the Tailpipe Rule, leaving both of those decisions intact.[102] However, the Supreme Court did agree to hear challenges to the EPA's determination that GHG fall within the Clean Air Act's stationary source Title V and Prevention of Significant Deterioration (PSD) permitting programs as a result of the Agency having adopted regulations limiting GHG emissions from cars and trucks.[103] These rules are briefly described below.

c) Johnson Reconsideration, Tailoring, and Timing Rules

As a matter of background, the Clean Air Act's PSD provisions were developed to ensure continued maintenance of NAAQS, and thus apply largely to "attainment" areas.[104] As mentioned previously, NAAQS apply to criteria pollutants, and CO_2 is not on the list of criteria pollutants. Under the PSD program, stationary sources that emit more than 100 or 250 tons per year (depending on the type of source) of "any air pollutant" must obtain PSD permits before beginning construction on or making major modifications to any "major emitting facility."[105] Facilities subject to PSD requirements must use Best Available Control Technology (BACT) for each pollutant emitted by the facility that is "subject to regulation" under the Clean Air Act.

As a result of an EPA Environmental Appeals Board ruling, in March 2010 the EPA set out to clarify precisely when pollutants would become "subject to regulation" and to BACT and other requirements under the PSD program.[106] The EPA's Administrator Stephen Johnson issued a memo (the Johnson Memo) reaffirming that a pollutant is "subject to regulation" when the pollutant is subject to actual controls, and the EPA issued a decision known as the "Timing Rule" reaffirming that interpretation.[107] The rule made PSD and Title V requirements apply as of the effective date of the Tailpipe Rule, beginning January 2, 2011.[108]

In May 2010, before the Tailpipe Rule went into effect, the EPA finalized what became known as the "Tailoring Rule" that "tailored" (i.e., raised) the applicability thresholds of the PSD and Title V operating permit programs with respect to GHG. Instead of applying the standard applicability thresholds for criteria pollutants, the permitting thresholds applied to GHG emissions would initially be orders of magnitude greater. The EPA thereby minimized the number of sources that would be immediately subject to permitting rules, by allowing smaller sources to avoid having to comply in the near term.[109] Large GHG sources such as new or modified

101 *American Electric Power Co. v. Connecticut,* 2011.

102 On October 15, 2013 the Supreme Court denied petitions for review of *Virginia v. Environmental Protection Agency,* Docket No. 12-1152; *Pacific Legal Foundation v. Environmental Protection Agency,* Docket No. 12-1153; and *Coalition for Responsible Regulation v. Environmental Protection Agency,* Docket No. 12-1253.

103 For example, whether *Massachusetts v. EPA* compelled the EPA to include GHG in the PSD and Title V programs is a question presented in *Utility Air Regulatory Group v. Environmental Protection Agency,* Docket No. 12-1146; and *Energy-Intensive Manufacturers Working Group on Greenhouse Gas Regulation v. Environmental Protection Agency,* Docket No. 12-1254.

104 In October 2013, in a non-GHG context, the Kansas Supreme Court ruled unanimously to reverse Kansas Department of Health and Environment's decision to grant a permit for the Sunflower Electric Power's proposed 895-MW coal-fired power plant project in December 2010. The Court sent it back to the state agency for not having required the plant to meet stricter federal air emission standards that the EPA had imposed before the permit was issued for the new plant. More specifically, the Court held, among other things, that an applicant for a PSD permit must demonstrate that the project will not cause air pollution in excess of any NAAQS even if the standard has not been incorporated into Kansas' SIP, unless the federal regulatory requirements specifically provide otherwise. Dillon, 2013.

105 Major Emitting Facilities on Which Construction is Commenced, 1977.

106 As a matter of practice for the EPA, a pollutant is not "subject to regulation" until some rule or statute requires emissions controls. The EPA's Environmental Appeals Board issued a ruling in November 2008 calling into question that interpretation and directing the EPA to reconsider whether to impose a CO_2 BACT limit on a proposed coal-fired power plant.

107 The EPA's decision on reconsideration of the Johnson Memo (i.e., the Timing Rule) was issued March 29, 2010.

108 *Coalition for Responsible Regulations v. EPA,* 2012.

109 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Final Rule, 2010. Had EPA applied the 100/ 250 ton thresholds to GHG, this would have resulted in a much larger number of emissions sources becoming subject to the permitting program. The EPA has not precluded extending the permitting requirements to smaller GHG sources in the future.

fossil-fueled power plants were not spared by the Tailoring Rule and have been subject to PSD and Title V permitting requirements since January 2, 2011. Thus, the Timing and Tailoring Rules establish, respectively, when and which stationary sources of GHG are subject to regulation under the EPA's PSD and Title V permitting programs.

Both the Timing and Tailoring rules were upheld by federal district and appellate court decisions. However, in October 2013 the Supreme Court agreed to hear an appeal based on a fundamental underlying question, namely whether the EPA permissibly determined that the Tailpipe Rule triggered PSD and Title V permitting requirements for stationary sources that emit GHG.[110] Should the Court decide that the EPA's determination was not permissible, the Timing and Tailoring rules would be moot, but the Endangerment Finding, the Tailpipe Rule, and any forthcoming GHG regulations under Section 111 of the Clean Air Act (described below) would be unaffected.

5. Clean Air Act Section 111 — NSPS for CO_2

- March 27, 2012, the EPA proposes NSPS for carbon pollution from new power plants
- September 20, 2013 the EPA rescinds its March 2012 proposal and issues a new proposal for carbon pollution from new power plants
- 60-day comment period post Federal Register publication
- Final Rule for NSPS TBD
- June 2014 the EPA will propose NSPS for carbon pollution from existing power plants
- June 2015 the EPA will propose NSPS for carbon pollution from existing power plants
- June 2016 states will file plans to demonstrate equivalency with NSPS

a) NSPS for New Sources — Section 111(b)

On September 20, 2013 the EPA proposed NSPS for CO_2 from new power plants. In June 2014 the EPA plans to propose NSPS for carbon pollution from existing power plants. The EPA is proposing to set separate standards for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and IGCC units.[111]

The electric sector is the largest concentrated source of CO_2 emissions in the United States, accounting for roughly one-third of all domestic GHG emissions.[112] Before the EPA took these steps there were no federal limits on those emissions.

The Clean Air Act is generally very prescriptive, in that specific pollutants are explicitly anticipated in different sections of the Act. For example, Section 112 focuses on air toxics like mercury, and Sections 108 and 109 focus on criteria pollutants like SO_2 and particulate matter. Section 111 does not follow that pattern. Unlike other, more specific sections of the Act, this section was not drafted with GHG in mind. Section 111 was designed to prevent pollutants not covered under the other, more prescriptive sections of the Act from going unregulated. Consequently, in many respects the EPA's 111(d) task is to build a program with little specific statutory guidance, which, of course, is a significant undertaking. In doing so, the EPA will have to develop a framework that strikes a balance between coordinating more than 50 jurisdictions under one program for fossil electricity generators, and empowering states to use the most effective and least expensive compliance options available. The EPA's proposed standards are intended to reflect different determinations of the best system of emission reduction that has been adequately demonstrated for utility boilers and IGCC units, and for natural gas-fired stationary combustion turbines. This proposal replaces the EPA's initial April 2012 proposal that set out a single standard with one best system of emission reduction determination for all new fossil fuel-fired units.

(1) Applicability

The EPA is proposing two limits for fossil fuel-fired utility boilers and IGCC units that allow compliance entities a choice between two compliance periods.

- 1100 lb CO_2/MWh gross over a 12 operating-month period, or
- 1000–1050 lb CO_2/MWh gross over an 84 operating-month (seven-year) period.

The EPA is proposing two standards for natural gas-fired stationary combustion units, depending on size. The proposed limits are based on the performance of modern natural gas combined cycle units. These proposed limits are:

- 1000 lb CO_2/MWh gross for larger units (>850 mmBtu/h)

110 *Utility Air Regulatory Group v. EPA,* 2012.

111 The rule does not apply to liquid oil-fired stationary combustion turbine EGUs; new EGUs that do not burn fossil fuels (e.g., those that burn biomass only); or to EGUs that sell less than one-third of their power to the grid.

112 Based on info from http://www.epa.gov/climatechange/ghgemissions/sources.html

- 1100 lb CO_2/MWh gross for smaller units (≤850 mmBtu/h)

(2) Potential for Flexibility

The EPA's NSPS for new sources requires new coal-fired units to install "partial" CCS technology as the best system of emission reduction to lower CO_2 emissions.[113] The EPA maintains that a "longer compliance period option provides flexibility by allowing sources to phase in the use of partial CCS."[114] Citing *Portland Cement Ass'n v. Ruckelshaus,* the Georgetown Climate Center has observed that "Courts have found that EPA has the authority to determine that a particular system of emissions reduction will be adequately demonstrated at a future date," a point the EPA noted in its 2008 Advanced Notice of Proposed Rulemaking.[115]

Although the lengthy compliance period would suggest significant flexibility, there is currently a debate as to whether or not new coal-fired generators could meet the requirements imposed by the EPA's NSPS for CO_2. There appears to be no agreement as to whether CCS has been adequately demonstrated. For example, a 2009 study prepared for the U.S. DOE by the Pacific Northwest National Laboratory evaluated the development status of various CCS technologies.[116] The study addressed the availability of capture processes; transportation options; injection technologies; and measurement, verification, and monitoring technologies, and concluded that:

In general, CCS is technically viable today. However, full-scale carbon separation and capture systems have not yet been installed and fully integrated at an [electric generating unit].[117]

On the other hand, in 2012, James Wood, the Deputy Assistant Secretary for the DOE's Office of Clean Coal, speaking at the Third International Advanced Coal Technologies Conference, an event sponsored by the Government of Shaanxi Province, China, and the State of Wyoming, remarked on the status of CCS technologies:

> *Unlike the cost-effective advanced technologies that were developed to reduce emissions of nitrogen, sulfur, mercury and particulates, technologies to capture and store carbon emissions from electric power plants are elusive, expensive and, although there are CO_2 separation technologies in use in the natural gas and chemical processing industries, there has not yet been widespread deployment in the electric power industry, and there is little history of the integration of these technologies with electric generation in reliable or cost-effective modes.*[118]

According to a publication entitled "The Global Status of CCS: 2013," produced by the Global CCS Institute, an Australian NGO established to promote CCS, this technology is relatively commonplace although its various applications are new:

> *CCS is often mistakenly perceived as an unproven or experimental technology. In reality, the technology is generally well understood and has been used for decades on a large scale in certain applications. For example:*
>
> - *Large-scale CO_2 separation is undertaken as a matter of routine in gas processing and many industrial processes;*
> - *CO_2 pipelines are an established technology, on land and under the sea; and*
> - *Large-scale injection and geological sequestration of CO_2 has been safely performed in saline reservoirs for more than 15 years, and in oil and gas reservoirs for decades.*
>
> *There are currently 12 operational large-scale CCS projects around the world, which have the capacity to prevent 25 million tons per year of CO_2 from reaching the atmosphere.*[119]

113 Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 2013.

114 According to the EPA, "The owner/operator can use some or all of the initial 84-operating month period to optimize the system." Id.

115 Georgetown Climate Center, 2011. See note 31 and accompanying text, citing to *Portland Cement Ass'n v. Ruckelshaus,* 486 F.2d 375, 391-92 (D.C. Cir. 1973) ("The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry."). See also, Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008.

116 Cited in U.S. EPA, 2010b page 26.

117 The study also did not address the cost or energy requirements of implementing CCS technology. For more information see: National Energy Technology Laboratory, undated.

118 Summary Report, 2012. Cited in Demase et al., 2013.

119 Global CCS Institute, 2013. The Global Carbon Capture and Storage (CCS) Institute is an not-for-profit company organized to promote "the development, demonstration and deployment of CCS globally through our knowledge sharing activities, fact-based influential advice and advocacy, and work to create favourable conditions to implement CCS." It has approximately 370 members from more than 40 countries, and offices in Australia, China, France, Japan, and the United States.

It is likely that this question and others will be raised in challenges to this regulation, resulting in uncertainty that is likely to persist for years to come. A key question, one reprising the discussion in the *Portland Cement Ass'n v. Ruckelshaus* case, will be whether a technology needs to enjoy "widespread deployment" to meet the legal standard of "adequately demonstrated"?

(3) Recommendations

Unlike Section 111(d), discussed below, that provides states with the ability to develop a SIP as provided for under Section 110 (with the attendant flexibility), or to consider "other factors" in setting performance standards, Section 111(b) does not empower the EPA with the same discretion.[120] The EPA's 111(b) standard is site-specific (i.e., within the fence) and gives fossil-fired boilers a choice between slightly different standards to be met in two (12- or 84-month) time periods. However, as noted above, while an 84-month compliance period would suggest significant flexibility, there is disagreement as to whether new coal-fired generators could meet the requirements.

What state regulators will need to do in this context is work closely with utility companies, air regulators, and system operators, where applicable, to monitor the ongoing debate over the availability of CCS technology. National associations like NARUC will also continue to be a good source for information and strategic thinking on this question. The National Association of State Energy Offices and the DOE will also be good sources for information on the status of CCS development.

In the context of utility resource planning, regulators should be wary of any long-term plan that includes new coal-fired generation without plans for CCS. Certainly if the 111(b) rule is finalized then default planning scenarios should assume CCS. However, in the interim, although a regulation can be overturned by the courts or a statute can be changed by lawmakers, utility plans should reflect the likelihood that this requirement will be in place and will apply to new coal-fired generation.

b) NSPS for Existing Sources – Section 111(d)

Depending on one's perspective, the development of NSPS for GHG emissions from the electricity sector poses the greatest cause for concern or possesses the greatest promise of all of the EPA's pending regulatory actions. NARUC has indicated that it "at this time takes no position regarding the merits of EPA rulemakings for the purpose of regulating GHG from new or existing power plants, despite having opinions as to how New Source Performance Standards, should be designed."[121] So, likewise, putting aside the merits of regulating GHG in the power sector, the following discussion seeks to highlight alternatives available, respectively, as the EPA articulates emissions standards and states develop compliance plans. As the discussion will demonstrate, 111(d) has the potential, owing to its novelty (it has seldom been used), to provide the EPA with significant leeway in setting standards and broad flexibility to the states to fashion plans regulating GHG remissions from their power sectors.

Section 111(d) applies to GHG emissions from existing power plants that have the same characteristics as the new power plants regulated under Section 111(b), and provides the EPA with the authority to require states to develop performance standards for these pollutants. The Clean Air Act sets out a two-step Federal/State process that the Supreme Court describes in *American Electric Power Co. v. Connecticut:*

> *For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction….*[122]

(1) Step One – The EPA's Role

Although referred to as "guidelines," in this process the EPA establishes binding requirements that states must address when they develop plans to regulate the existing sources in their jurisdictions.[123] In addition, the EPA is required to establish a compliance schedule for the states.

120 "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among *other factors,* the remaining useful life of the existing source to which such standard applies." Section 111(d)(B) (emphasis added). See also, Wannier et al., 2011 at p. 6.

121 National Association of Regulatory Utility Commissioners, 2013a.

122 *American Electric Power Co. v. Connecticut,* 2011 (citations omitted).

123 Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008 at p. 428.

The EPA can also subcategorize within the category of sources if appropriate. For example, as it did with the NSPS for new sources, the EPA could fashion different standards for coal-fired and gas-fired power plants and incorporate that in its guidelines.

The EPA's emissions guidelines must describe "systems of emission reduction that, in the judgment of the EPA Administrator, have been adequately demonstrated."[124] The guidelines must reflect "the application of the best system of emission reduction … that has been adequately demonstrated …."[125] These systems must also take into consideration cost of achieving reductions, any non-air quality health and environmental impacts, and energy requirements. Section 111(d) also directs the EPA to "take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."[126]

The EPA has indicated that setting emission guidelines for existing sources will require it to conduct a review that:

- Identifies what emission reduction systems exist for a particular pollutant and how much they reduce air pollution in practice;
- Identifies potential emission limits based on this review; and
- Evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation.[127]

Because of the liberal language of Section 111(d), the guideline-setting process need not be limited to site-specific (i.e., within the fence) technologies and practices such as those mandated, for example, under the PSD Program, in which permit writers for CO_2 are required to review the Best Available Control Technology. The guidelines direct the EPA to look more broadly at "systems of emissions reduction," which imply significant discretion for the EPA to look beyond site-specific strategies to GHG reductions available across the electric sector.[128] However, despite arguably having a broader mandate to recognize cost-effective "systems of reduction," which would inform its decision as to the "best" of those systems, the EPA has indicated that:

> *This level of control is commonly referred to as best demonstrated technology (BDT). In determining BDT, we typically conduct a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. This allows us to identify potential emission limits.*[129]

According to the Georgetown Climate Center, "the statute no longer includes the term 'technological' in its definition of the standard, however, and therefore 'BDT' may be misleading…."[130] States should recognize that, despite the EPA's use of the term BDT, the Clean Air Act reads more permissively asking for "systems of emissions reduction" rather than demonstrated technology.

(a) Establishing an Emissions Standard

In setting an emissions guideline, the EPA could articulate a standard in a number of ways. Several are considered here because they have been frequently raised in policy conversations. The EPA could take a "mass-based" approach, setting a limit on the discharge of a pollutant expressed as a weight per unit of time. "Pounds-per-day" or "tons-per-year" are mass-based standards. The acid rain program that regulates the same category of emitters being considered here requires continuous monitoring and reporting of mass emissions of SO_2 and CO_2.[131] The EPA, alternatively, could adopt what is referred to as a "rate-based" approach, that is, an amount of pollutant per unit of energy produced, such as pounds of CO_2/MWh. Again, the acid rain program requires the same class of emitters to monitor and report this kind of emissions rate for NOx. Furthermore, the EPA could express the standard as a percentage reduction from an agreed upon baseline, which in turn could be articulated in mass-based or rate-based terms. It should be emphasized that, although the EPA's guidelines will have to articulate a standard, it is not clear at this point precisely how or in how many ways they will do this.

(b) Setting a Numerical Emissions Limit

In 2010 the EPA identified a number of technologies and

124 Publication of guideline documents, emission guidelines, and final compliance times, 2009.

125 Id.

126 Clean Air Act of 1970, Section 111(d)(2)(B).

127 Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008.

128 Emphasis added.

129 Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008 at p. 426.

130 Georgetown Climate Center, 2011. See note 1 and accompanying text.

131 The EPA has developed NSPS for municipal waste incinerators using a mass emissions rate.

132 U.S. EPA, 2010b; National Energy Technology Laboratory, 2008.

Selected CO_2 Reduction Technologies and Strategies[133]

Combustion Control Optimization (reported efficiency increase: 0.15 to 0.84 percent)

Combustion controls adjust coal and air flow to optimize steam production for the steam turbine/generator set. However, combustion control for a coal-fired EGU is complex and impacts a number of important operating parameters including combustion efficiency, steam temperature, furnace slagging and fouling, and NOX formation. The technologies include instruments that measure carbon levels in ash, coal flow rates, air flow rates, CO levels, oxygen levels, slag deposits, and burner metrics as well as advanced coal nozzles and plasma-assisted coal combustion.

Cooling System Heat Loss Recovery (reported efficiency increase: 0.2 to 1 percent)

These systems recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation through a cooling tower or discharge to a water body. Identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser.

Flue Gas Heat Recovery (reported efficiency increase: 0.3 to 1.5 percent)

Flue gas exit temperature from the air preheater can range from 250°F to 350°F, depending on the acid dew point temperature of the flue gas, which is dependent on the concentration of vapor phase sulfuric acid and moisture. For power plants equipped with wet FGD systems, the flue gas is further cooled to approximately 125°F as it is sprayed with the FGD reagent slurry. However, it may be possible to recover some of this lost energy in the flue gas to preheat boiler feedwater via use of a condensing heat exchanger.

Low-Rank Coal Drying (reported efficiency increase: 0.1 to 1.7 percent)

Subbituminous and lignite coals contain relatively large amounts of moisture (15 to 40 percent) compared to bituminous coal (less than 10 percent). A significant amount of the heat released during combustion of low-rank coals is used to evaporate this moisture, rather than generate steam for the turbine. As a result, boiler efficiency is typically lower for plants burning low-rank coal. Identified technologies include using waste heat from the flue gas and/or cooling water systems to dry low-rank coal prior to combustion.

Sootblower Optimization (reported efficiency increase: 0.1 to 0.65 percent)

Sootblowers intermittently inject high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces in order to maintain adequate heat transfer. Proper control of the timing and intensity of individual sootblowers is important to maintain steam temperature and boiler efficiency.

strategies that existing coal-fired units could employ. These within-the-fence approaches are likely to contribute to the development of an emissions level that the EPA proposes in its guidelines.[132] These technologies and strategies include such approaches as, for example, flue gas heat recovery and coal drying to remove excess moisture from coal before it is burned (see "Selected CO_2 Reduction Technologies and Strategies" Text Box). As discussed further in "Flexibility for States" below, the EPA potentially has a larger range of choices that could broaden its analysis of adequately demonstrated systems of emissions reduction beyond these within-the-fence technologies.

(2) Step Two — The Role of the States

In compliance with the EPA's guidelines and subject to EPA approval, 111(d) requires states to issue performance standards. Section 111(d) requires the EPA to put in place a procedure similar to the process outlined in Section 110 of the Clean Air Act where states develop SIPs for EPA approval. In the context of Section 111(d), these plans are referred to as "Equivalency Plans." The EPA can issue model standards intended to help states as they develop their plans[134] (see the "40 CFR Section 60.22" text box). As discussed further below, equivalency plans contain a state's strategy for complying with the EPA's emissions guidelines, and provide justification for the approaches adopted.[135]

(a) EPA/State Process

By employing Section 110 as the template for state action, Congress has provided the states with significant

133 U.S. EPA, 2010b; National Energy Technology Laboratory, 2008.

134 Georgetown Climate Center, 2011 note 39 and accompanying text, citing to Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008.

135 Section 111 cites to Section 110: "The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section [110] of this title under which each State shall submit to the Administrator a plan." Id.

leeway in the means at their disposal to meet Section 111(d) requirements. Section 110(a)(2)(A) lists a broad array of policy mechanisms allowed in a state's SIP:

> Each such plan shall—
>
> (A) Include enforceable emission limitations and other control measures, means, or techniques *(including economic incentives such as fees, marketable permits, and auctions of emissions rights)*, as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter.[136]

Although states are afforded significant flexibility under Section 110, they are also bound by certain limits in this process. For example, SIPs must be "no less stringent" than the EPA's emissions guideline. Still states have some leeway to vary under certain conditions from the guideline. For example, according to the general guideline, the assumption is that a state plan has to be submitted within 12 months after the EPA guideline is issued, although states can ask the EPA to alter the schedule, as long as it remains consistent with Section 111(d).

There is also the potential for states to get a variance or waiver from other aspects of the general guidelines. According to 40 C.F.R. Section 60.24(f):

> States may provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):
>
> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility of installing necessary control equipment; or
>
> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.[137]

In reflecting on Section 60.24(f) of the EPA's regulations, Georgetown Climate Center's 2011 "Issue Brief" notes that:

> Some commentators have suggested that allowing states to include flexibilities such as averaging or trading… significantly limits the need for such waivers, as individual facilities that might otherwise have an unreasonably high compliance cost can take advantage of less expensive abatement options at other facilities to comply with the standard.[138, 139]

(b) The Current Schedule

President Obama has directed the EPA to propose a rule in June 2014 and finalize it by June 2015. Consequently there is an opportunity, although limited, for states and others to provide comment before a proposed rule is published. With an interagency consultation process prior to June (e.g., 60 days), and some amount of time for the EPA to actually draft the rule, there is very little time for states to provide comments and direction to the EPA prior to the development of the proposed rule. There will, of course, be a public comment period after the rule is proposed and before the issuance of a final rule. However, states should provide the EPA with relevant data and suggestions as to how the EPA might accommodate one's state in this process before the rule is proposed in June 2014.[140]

EPA regulations require the EPA to publish a compliance schedule as part of a proposed and final guideline, including a schedule for states to submit equivalency plans.[141] Under the current regulations, the EPA gives states 12 months from publication date of the final guidelines to submit their plans.[142]

(c) Ensuring Flexibility for States

As noted previously, there is an opportunity in the next several months for states to provide the EPA with comments and to encourage the EPA to recognize additional flexibility with respect to (a) the EPA's development of emissions guidelines and (b) leeway for

136 Section 110 (emphasis added).

137 Emission standards and compliance schedules, 2013. Section 60.24(f).

138 Georgetown Climate Center, 2011 note 47 and accompanying text.

139 The statute and the regulations permit states and the EPA to set less stringent standards or longer compliance schedules for existing sources where warranted considering cost of control; useful life of the facilities; location or process design at a particular facility; physical impossibility of installing necessary control equipment; or other factors making less stringent limits or longer compliance schedules appropriate. Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008 at p. 429.

140 See text box "A Model for State Equivalency — The Kentucky Proposal" on page 39 for a description of Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act.

141 Adoption and submittal of State plans; public hearings, 2013. Section 60.23(a)(2).

142 Id.

state development of performance standards in Equivalency Plans.[143] The following section discusses some of the factors the EPA could consider as it sets guidelines and some of the issues states may want to explore as they organize themselves to develop Section 111(d) Equivalency Plans.

The EPA's Development of Emissions Guidelines

As noted previously, the first part of the Section 111(d) process involves the EPA setting emissions guidelines. States should encourage the EPA, as it reviews various systems of emissions reductions in order to establish guidelines, to recognize that the states have different resources available for meeting the requirements that the EPA will establish, and furthermore that each state will need the flexibility to comply in a manner that it concludes is appropriate. The EPA should be receptive:

The EPA believes the unique characteristics of carbon pollution and the interconnected nature of the electric power sector call for a broad and flexible approach to designing the program for existing power plants.[144]

The EPA is very likely to include the various within-the-fence compliance options that are currently available to fossil generators, although Acting Assistant Administrator for the Office of Air and Radiation, Janet McCabe, announced at the November NARUC meetings that the EPA's emissions guideline would not be based on retrofitting CCS on existing plants.[145] As the illustrative list in the "Selected CO_2 Reduction Technologies and Strategies" text box demonstrates, there are a number of compliance technologies that generators can install at plants to achieve some amount of emission reductions.[146] These technologies vary in their effectiveness. For example, the reported efficiency increase for low-rank coal drying is 0.1 to 1.7 percent. For flue gas heat recovery it is 0.3 to 1.5 percent.[147] Although representing small efficiency gains, some of these resources can be installed in combination.

It should be noted, however, that most of these resources are likely to be long-lived investments and to have energy requirements producing some amount of parasitic load at the facilities where they would be installed. Energy used to serve that load is thus unavailable for general use and must be otherwise generated, potentially producing additional emissions.

Model Standards

40 CFR Section 60.22, the EPA emissions guidelines must contain the following:

a. Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

b. A description of systems of emission reduction that, in the judgment of the EPA Administrator, have been adequately demonstrated.

c. Information about the degree of emission reduction that is achievable with each system, together with information about the costs and environmental effects of applying each system to designated facilities.

d. Incremental periods of time normally expected to be necessary for the design, installation, and start-up of identified control systems.

e. An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for the different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

f. Other available information as the Administrator determines may contribute to the formulation of the states' plans.

143 During the November 2013 Annual NARUC Meeting, in response to a question posed by Indiana Commissioner David Ziegner as to whether it was too premature for state commissions to start to act with state environmental commissions on section 111(d), Acting Assistant Administrator for the Office of Air and Radiation, Janet McCabe stated: "It's not too early at all. It is a prime time to do that," and further explained how the EPA has been participating in teleconferences with EPA Regional Offices, state environmental regulators, energy offices, and Public Utility Commissions on the topic. NARUC/FERC Joint Forum on Reliability and the Environment. NARUC 125th Annual Meeting, November 19, 2013.

144 U.S. EPA, 2013g.

145 NARUC/FERC Joint Forum on Reliability and the Environment. NARUC 125th Annual Meeting, November 19, 2013.

146 U.S. EPA, 2010b.

147 Id.

In order to capture the range of possible systems of emissions reductions, the EPA will need to look more broadly at compliance options, in addition to those that might be employed only on-site at fossil generating units. These "outside the fence" options, such as end-use efficiency or renewable generation, are available across the electric system and constitute potential solutions that could require both metered and statistical approaches to substantiate.

Considering, for example, end-use energy efficiency, which is likely the lowest-cost resource available on the electric system, there are a number of types of technologies that the EPA might consider. For the residential sector, the technologies could include high-efficiency appliances such as air-conditioners, water heaters, and refrigerators, among many others. Examples of energy efficiency used in the commercial and institutional sectors include building envelope improvements and high-efficiency electric motors. The industrial sector could also invest in various process improvements and high-efficiency motors and drives, and combined heat and power.

The EPA has recognized the cost-effectiveness of end-use efficiency in numerous regulatory contexts.[148] For example, in developing the MATS rule, the EPA acknowledged that compliance costs could be significantly reduced and emissions avoided by including energy efficiency investments in compliance strategies that achieve even moderate levels of energy demand reduction:

> *End-use energy efficiency can be an important part of a compliance strategy for this regulation. It can reduce the cost of compliance, lower consumer costs, reduce emissions, and help to ensure reliability of the U.S. power system. Policies to promote end-use energy efficiency are largely outside of EPA's direct control. However this rule can provide an incentive for action to promote energy efficiency.*[149]

To examine the potential impacts of federal and state energy efficiency policies on MATS compliance, the EPA used the Integrated Planning Model.[150] The EPA assumed, first, that the states adopted ratepayer-funded energy efficiency programs, such as an energy efficiency resource standard. The EPA's model relied on savings estimates taken from work conducted by Lawrence Berkley National Laboratory.[151] Second, the EPA has also used DOE estimates of "demand reductions that could be achieved from implementation of appliance efficiency standards mandated by existing statutes but not yet implemented."[152] Third, the EPA assumed that the impacts of these policies would continue through 2050.[153] While not using avoided emissions from efficiency savings for purposes of MATS compliance, the EPA relied on efficiency savings and related emissions reductions to secure lower compliance cost estimates.

In its July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans," the EPA recognized the potential of end-use energy efficiency to avoid power sector emissions and help states to come into compliance in nonattainment areas.[154] The EPA is also considering including end-use energy efficiency as a means of mitigating

148 See "Measuring the Air Quality Impacts of Energy Efficiency," a webinar series developed by Chris James and John Shenot (RAP). Over the course of 2012, RAP delivered a series of webinars on the broad theme of quantifying the air quality impacts of energy efficiency policies and programs to an Energy Efficiency/Air Quality Planning Workgroup convened by the Northeast States for Coordinated Air Use Management and the Ozone Transport Commission. See also, Shenot, 2013.

149 National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 2011.

150 It first modeled a base case that reflected future energy prices and bills without MATS. The EPA modeled future prices and bills with the standard. Then they modeled with MATS plus energy efficiency.

151 National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 2011, citing to, Barbose, et al., 2009.

152 The EPA notes that "appliance standards that have been implemented are in [the MATS] base case." Id.

153 Id. See Tables 22 and 23 at 545–546.

154 EPA describes an option which states have had for nearly a decade, states now have three other options or "pathways" for including EE and RE in their SIPs, and the previous limit on the use of EE as a strategy has been lifted. The EPA is also in the process of developing some quantification tools to help states determine the emissions avoided through EE and RE.

potential control technology costs associated with PSD and Title V GHG permitting for small emissions sources such as commercial buildings and hospitals. EPA Administrator McCarthy has acknowledged the value of energy efficiency in this context, citing examples such as the EPA's Energy Star Programs and Portfolio Manager, its open access building energy- and water-use benchmarking tool.[155]

The fact that energy efficiency is an aggregation of dispersed end-use technologies should not be a bar to the EPA's adoption of energy efficiency as one of the systems of emissions reductions that it considers in setting CO_2e emissions guidelines under Section 111(d). One way that the EPA might address this challenge, an approach that RAP has pioneered, is to quantify reductions associated with energy efficiency measures analogously to the manner in which mobile sources (vehicles) are currently treated.[156] The EPA has experience in modeling emissions reductions associated with millions of discrete installations such as pollution controls on trucks and automobiles. And the EPA has the capacity to model avoided emissions associated with energy savings in the power sector in the same way.

Mobile source emissions estimates typically include assumptions, for example, about the fleet's baseline emissions, anticipated penetration of new and better technologies, the manner in which technologies will be used, and the degree to which they will be effective. In more concrete terms, the EPA makes assumptions about vehicle miles traveled, average speeds, and useful lives of various types of vehicles, just as they could in an energy context with respect to emissions avoided owing to energy efficiency measures, portfolios, and programs. Mobile source emissions estimates are equally difficult to precisely characterize, yet mobile source emission reduction programs are routinely incorporated in state SIPs.

Done correctly, evaluation, measurement, verification, and enforcement for energy efficiency appears to be as or more robust than that for mobile sources. If mobile source emissions can be reliably quantified via statistical sampling and analysis, then why not apply the same approach to energy efficiency as part of establishing NSPS CO_2e emissions guidelines?

Encouraging the EPA to include energy efficiency, among other clean energy policies and investments, in the emissions guideline process will help ensure that the EPA conducts a broadly inclusive review of emissions reduction systems as required by the Clean Air Act, and avoids producing guidelines based solely on a review of a limited number of more expensive on-site technologies that come with their own environmental impacts and energy requirements.[157]

One final point must be considered, because a number of state Constitutions prohibit the adoption of environmental regulations that are different or more stringent than those articulated in a federal program. Unless the EPA is explicit in its characterization of compliance alternatives, some states may not be able to enjoy the flexibility available to other states that don't face those limitations. So states should not only encourage the EPA to be flexible with respect to compliance approaches, but to articulate the allowable approaches as explicitly as possible.

State Development of Performance Standards in SIPs

As noted previously, the language of Section 110 specifically directs states to employ enforceable emission limitations in their SIPs, ensuring the ability of states to take action to control pollution. In addition to the first criterion, "enforceability," the statute speaks without limit to "other control measures, means, or techniques" to achieve the same emission limitation goals.

Furthermore, Section 110 lists examples of flexible compliance approaches in case the broader language is unclear, recognizing "incentives" such as "fees, marketable permits, and auctions of emissions rights." For purposes of state action, Section 111(d)'s reference to Section 110 should be recognized as a green light for states to develop specific ways to meet the EPA's guidelines that recognize and incorporate the many clean energy investments that states have made and can position themselves to make in the future.

The various approaches that have been proposed by organizations and others are referred to under the heading of "State Equivalency Plans." A number of organizations have developed proposals for curbing GHG under the Clean Air Act; several brief illustrations are provided here. In 2011, the Natural Resources Defense Council developed an extensive study titled, "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," in which it proposes that the EPA

155 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations, 2012; see also Parker, 2013.

156 Colburn, 2013.

157 Regulating Greenhouse Gas Emissions Under the Clean Air Act, 2008.

establish standards that set pollution limits tied to the energy mix of each state, and give electricity utilities flexibility to meet targets in cost-effective ways.[158] The State of Kentucky, as well, has developed a proposal titled, "Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act," that contains an extensive list of provisions that Kentucky might pursue as a means of ensuring the state's compliance.[159]

Other examples include Resources for the Future's paper, "Technology Flexibility and Stringency for Greenhouse Gas Regulations," an approach that articulates a CO_2 emissions rate standard that allows averaging across the generation sector, and avoids the higher cost strategy of penalizing coal plants only.[160] Another proposal from the National Climate Coalition recommends among other things that the EPA's guidelines should adopt an emissions rate, subcategorize sources according to fuel and technology type, mandate reductions based only on within-the-fence emission reduction opportunities at the stationary source, but allow inter-source and interstate emissions averaging, banking, and trading.[161] These approaches have in common the assumption that the EPA should be flexible as long as state plans achieve GHG emissions at levels that are at least equivalent to the emissions reductions that would be achieved under the EPA's guidelines.

Section 111(d)'s reliance on Section 110 SIP compliance has provided the basis for many parties, including the EPA at one time, to argue that Section 111 affords states significant flexibility in implementing NSPS.[162] Georgetown Climate Center identified the following categories for flexible regulatory approaches that go beyond what might be considered more traditional performance standards.[163]

A Model for State Equivalency — The Kentucky Proposal

A number of organizations have developed proposals for curbing GHG under the Clean Air Act. The State of Kentucky has developed a proposal that contains an extensive list of provisions that the EPA might consider. "Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act" indicates that an equivalency plan for Kentucky would:

1. Establish a statewide baseline CO_2 level using the CO_2 emission from fossil fueled electric generating units from 2005.
2. Establish the following baseline CO_2 reduction targets for 2020 (17-percent reduction), 2025 (28-percent reduction), and 2030 (38-percent reduction). Beyond 2020, state-specific data as well as energy portfolio trends would be used to set additional reductions beyond 2020 achievable through demand-side and supply-side efficiencies, renewable and other low-carbon energy potential, offsets, and any control technology gains. The 2050 target is the 80-percent reduction goal proposed by President Obama.
3. Obtain credit for CO_2 reductions that have occurred from the baseline established in item 1, thereby allowing states to comply with baseline reduction targets established in item 2.
4. Allow a suite of compliance options that would enable Kentucky to implement the least-cost method of meeting reduction targets. These compliance options would include, but not be limited to:
   - Demand-side energy efficiency
   - Supply-side conservation or efficiency programs
   - Transmission upgrades
   - Renewable and other low-carbon energy projects at the affected source or at the consumer level
   - CCS technology
   - Fuel switching to lower emitting fuels
   - Quantifiable and verifiable offsets
   - Participation in regional or national market-based CO_2 credit-trading programs
5. Establish an enforcement and monitoring mechanism whereby the state would be responsible for review, verification of emission estimates and reductions, and approval of the compliance options above. In addition, the state would be responsible for tracking statewide trends and projects.

158 See e.g., Lashof, et al., 2013.

159 See Text Box "A Model for State Equivalency — The Kentucky Proposal."

160 Burtraw & Woerman, 2013.

161 National Climate Coalition, 2013.

162 Under the Clean Air Mercury Rule, the EPA proposed an NSPS trading program for sources of mercury. Owing to the EPA's delisting of fossil generators as emitters of mercury that was found illegal, the EPA was not able to implement its NSPS proposal. Although the court rejected the EPA's proposed trading program, they did so because of the EPA's inappropriate "delisting" under Section 112 (air toxics) of fossil generators as mercury emitters, not because the NSPS process could not accommodate a trading program.

163 Georgetown Climate Center, 2011. Georgetown describes a traditional performance standard as a "rate-based standard applied at each facility or unit, or different rate-based standard based on separate fuel type could be applied to a category or subcategories of generators." Id.

Averaging Programs

These programs would focus on average emissions or emissions rates associated with larger groupings of emitters (e.g., facilities, firms, fleets, or states). This would enable emissions reductions to be performed by the least expensive sources first inside a given group.

Trading Programs

The Regional Greenhouse Gas Initiative and California's AB32 programs have developed an emissions cap, and an emissions and allowance tracking system to record and track market and program data, including CO_2 emissions from regulated power plants and CO_2 allowance transactions among market participants.[164] The EPA could establish an emissions guideline that trading program member states could demonstrate that they meet or exceed by virtue of their participation in a trading program.

Plans Reflecting Renewable Energy, Clean Energy, and End-Use Energy Efficiency Programs

Many states have renewable energy, clean energy, and energy efficiency programs that are displacing the use of fossil fuel fired generation, and thus avoiding GHG emissions. To the degree that these programs are able to demonstrate this, EPA could recognize the effect that these programs have on emissions from the fossil generation sector. The Kentucky 111(d) proposal, discussed above, fits into this category.[165]

Negotiated Agreements

States could make the demonstration that overall policies to shutdown older, dirtier and less efficient generators and replace them with newer and cleaner resources have significant GHG reduction benefits that EPA should recognize.[166] EPA could establish an emissions guideline allowing states to develop plans based on similar negotiated agreements that would secure at least the same level of emissions reductions that EPA establishes in it guidelines.

Planning for a Plan—Steps that States Can Take in Developing an Equivalency Plan

Assuming that EPA will grant states sufficient flexibility to develop Equivalency Plans, and due to the short timeline, states should immediately take the opportunity to explore the full range of potential means of reducing GHG emissions in their state's electric sector.[167] States can take the initial step by cataloguing categories of available or potentially available resources, including inside-the-fence compliance options, upon which states could rely in developing an Equivalency Plan.

An Equivalency Plan can be thought of as containing different "modules" that represent the various categories of resources available to a State. For example, Kentucky's plan contains the following modules:

- Demand-side energy efficiency
- Supply-side conservation or efficiency programs
- Transmission upgrades
- Renewable and other low-carbon energy projects at the affected source or at the consumer level
- CCS technology
- Fuel switching to lower emitting fuels
- Quantifiable and verifiable offsets
- Participation in regional or national market-based CO_2 credit-trading programs[168]

In assessing the resources available, states can take the same approach adopted by Kentucky. States can then add further specificity to each module. Taking Kentucky's first module, "Demand-side energy efficiency" as an example, states could enumerate the various efficiency policies that they might have in effect or decide to pursue. These might include:

- **Codes and Standards.** These are mandated minimum efficiency requirements for buildings and minimum energy performance standards for new energy consuming equipment. These are typically imposed on builders and equipment and appliance manufacturers.
- **Integrated Resource Planning.** IRP is a regulatory requirement that electric and gas providers analyze efficiency as well as supply-side options for meeting their customers' needs and commit to the least-cost combination of those investments.

164 See Letter from Regional Greenhouse Gas Initiative State Agency Heads to Regina McCarthy, 2011.

165 See, Farnsworth, 2011 for discussion of Colorado's Clean Air – Clean Jobs Act at pp. 20–34; see also Epel, 2012.

166 See id. The Colorado Clean Air – Clean Jobs Act is a program combining features of both Georgetown's "Plans Reflecting Renewable Energy, Clean Energy, and End-Use Energy Efficiency Programs" and "Negotiated Agreements" categories.

167 The discussion that follows focuses on individual states, although it would appear that the flexibility that the EPA is capable of accommodating would include multistate efforts.

168 Kentucky Energy and Environment Cabinet, 2013.

- **Binding Energy Savings Targets.** Binding targets specify levels of energy efficiency savings that must be acquired and by whom they must be acquired. They are typically set either legislatively or by energy regulators based on legislative guidance.
- **Voluntary Agreements.** These are agreements typically by a large energy consumer to improve energy efficiency by an agreed amount. They are often established between government and large energy end-users and sometimes linked to avoiding certain taxes or levies if the agreed target is met. They may be in terms of absolute energy consumption or consumption per unit of the consumer's output, such as MWh per unit of value added or per unit of service provided.
- **Enabling New Markets for Energy Efficiency.** Under this approach, government changes the ways in which energy markets function so that the markets themselves will cause efficiency investments to be made. This can occur by allowing efficiency (and other demand resources) to compete on price with generators, transmission providers, and other supply alternatives to meeting various energy sector needs (e.g., acquiring peak electric capacity, addressing transmission reliability, meeting system-level energy needs). Although this approach has not yet been fully tested to meet all of these needs, there is growing interest in considering new ways to enable markets (e.g., efficiency "feed-in-tariffs").[169]

As states assess the suitability of compliance resources available under each module, the potential next step might be to determine, for example, what programs the state is currently supporting and which could use more support, what new programs the state might consider undertaking, and the steps needed to put such efforts in motion. On the basis of a review of "Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act," it is apparently this process that Kentucky has recently undertaken.

One final observation on Equivalency Program planning: as states consider the benefits and costs of elements in each Program Module, states should also consider to what degree the EPA might be able to count the efforts in each of these plans toward compliance with related EPA regulatory requirements. Greater energy efficiency investment, for example, should not only help a state with Section 111(d) compliance, but could also reduce MATS compliance costs as previously noted, help the state with attainment of forthcoming ozone standards, and even help the state comply with an eventual air transport regulation that the EPA develops once the Homer City CSAPR appeal is decided.

3) Recommendations

States should recognize that Section 111(d) does not mandate a specific compliance technology, but instead directs the EPA and the states to use "best systems of emissions reductions."

Because the EPA will be covering new ground in developing proposed Section 111(d) guidelines in June 2014, states should recognize the limited amount of time available for them to help the EPA in this effort by providing the EPA with comments that articulate state-specific concerns.

Because Section 111(d) is largely uncharted territory for the EPA, states could be especially helpful in shaping the guidelines the EPA ultimately proposes. States should recognize the EPA will need to build a record upon which it develops its proposal. States should therefore be providing the EPA with relevant data and direction as to how the EPA might develop emissions guidelines. Utility and generation companies will be doing this. In order to ensure that the EPA's proposal will contain all the elements states want to develop as part of their equivalency plans, states need to do this as well.

States likewise need to be specific and provide the EPA with the necessary elements of an equivalency plan that will work for the state. An equivalency plan can be thought of as containing different "modules" that represent the various categories of resources available to a state. It is not too soon for states to begin assessing the emissions reductions that might be achievable through each module, and the associated costs, in preparation for developing an equivalency plan.

Where applicable, states should also inform the EPA as to any limitations in state law that would hinder a state's ability to go beyond federal guidelines. With that knowledge, the EPA can go further than it would otherwise go in articulating alternative steps that states may want to take in developing their plans.

169 Wasserman & Neme, 2012.

III. Part II – Market Factors Affecting Coal Retirements

A. Introduction

The purpose of discussing EPA regulations has been to provide an understanding of the broad aspects of the EPA's regulatory proposals and their potential effects on power markets. It has become evident over the last several years that the EPA's public health and environmental regulatory initiatives play a part in a larger constellation of factors that affect the power generation sector and utility decision-making. Readers thus should also be aware of the numerous market factors that are having or could have significant effects on the power generation sector and on utility company decision-making.

In 2010 and 2011 when the potential effects of new EPA regulations were being raised in public discourse, there were a significant number of cautionary analyses focused on the potential threats to electric system resource adequacy and system reliability from potential plant closures owing to pending regulations. Although largely driven by concerns over compliance costs, in retrospect some of the concerns raised may have resulted simply from a lack of information.

For example, in October 2010, NERC concluded that potential impacts of pending EPA regulations would result in retrofits or retirement of approximately 33 to 70 GW of capacity by 2015.[170] Because none of the regulations it considered in 2010 had been finalized, NERC had to rely on the incomplete information, and on its judgment as to how strict an approach the EPA would take. NERC concluded that the Section 316(b) cooling water intake rule had the "greatest potential impact" on Planning Reserve Margins…"[171] and found that "of this capacity, 33-36 GW…may be economically vulnerable to retirement if the proposed EPA rule requires power suppliers to convert to recirculating cooling water systems in order to continue operations."[172] As discussed in Section 1, the EPA's Section 316(b) regulation does not propose to require recirculating cooling water systems (i.e., closed-cycle cooling) and the associated cost threat of that rule has not materialized.

Two years later, NERC issued its "2012 Long-Term Reliability Assessment" and projected that "about 71 MW of fossil-fired generation would retire by 2022, with over 90 percent retiring by 2017."[173] While continuing to expect similar amounts of retirements, several of NERC's "Key Reliability Findings" recognize that:

- With the exception of ERCOT… the retirement of this capacity does not pose significant resource adequacy concerns.[174] Reserve margins are likely to be reduced, but to levels that are still above targets,[175] and
- For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability through the long-term horizon (i.e., 2022).[176] Future uncertainties include electricity market changes, fuel prices (natural gas in particular), potential environmental regulations, and renewable portfolio standards.[177]

In its subsequent "2013 Summer Reliability Assessment," NERC states that it did not anticipate that "retirements and retrofits to meet future environmental regulations" would

170 NERC, 2010.

171 Id. Planning reserve margins are "the amount of generation capacity available to meet expected demand plus a reserve margin in the planning horizon in the various reliability regions of the country."

172 Id. Page IV.

173 Schrayshuen et al., 2012.

174 Id. NERC indicated that in 2013 ERCOT's planning reserve margin was anticipated to be 13.4 percent, which is below NERC's reference margin level of 13.75 percent.

175 Id. It recognizes that reserve margins are likely to be reduced, but to levels that are still above targets. It further notes, however, that "retirements over the next three to four years may raise issues related to system stability…."

176 Id.

177 Id.

"cause reliability concerns this summer."[178]

Generally speaking, current discussions characterizing the status of the U.S. power system recognize that ensuring resource adequacy and preserving system reliability is not a matter of one single factor, like public health regulations, but instead is a finer-grained analysis involving numerous factors. These include relative fuel costs, especially between coal and natural gas, but also considering nuclear power and the many renewable forms of power, reduced demand for electricity, and the inability of older and less efficient generation units to compete with newer, less polluting and more efficient resources, whether in traditional service territories or in areas with wholesale power markets.[179] It is also worth noting that not only are commentators now looking at these additional factors, but the discussions of specific EPA regulations themselves point out that there are a number of instances in which they are actually less restrictive, and their effects less disruptive than originally expected.

This section contains a brief look at several recent updated discussions of how EPA regulations might affect the power system. Brattle, NERC, and others have conducted recent analyses of pending EPA regulations and various additional factors affecting the power market and plant closure decisions today, many of which are likely to be factors affecting current utility company planning and acquisition decisions. In the fall of 2012, the Brattle Group published an update to its 2010 publication, "Potential Coal Plant Retirements." In its 2012 publication, Brattle concludes that the "energy market outlook and emerging environmental regulations have changed substantially since we last studied the potential for coal plant retirements in December 2010."[180] Brattle indicates that:

> *The decrease in spot and forward gas prices combined with low demand for power have caused projected energy margins and the cost of replacement power to decrease, altering the economics for coal units towards retirement versus retrofit decisions. On the market side, the projected energy margins for coal plants have decreased and the need for capacity has been deferred.*[181]

Relying on a "lenient" and "strict" scenario, Brattle's 2012 analysis concludes that 59 GW to 77 GW, respectively, of coal plant capacity is more likely to retire than retrofit with environmental equipment, and that this would occur "absent any future regulations restricting carbon emissions."[182]

Brattle further explains that its recent conclusions are approximately 25 GW higher than the retirement levels it had projected in its earlier 2010 analysis, and that this is attributable mainly to lower expected gas prices and "despite the somewhat more lenient environmental regulations we currently envision."[183] In considering the role of regulations, Brattle found that:

- "CSAPR and MATS were finalized with less restrictive requirements on the compliance deadlines and equipment than previously predicted."
- "EPA's proposed 316(b) rule was less onerous than some had predicted due to EPA's decision to not require universal installation of cooling towers."
- CSAPR's status adds an "increased level of uncertainty regarding the timing and requirements under a potential future proposal by the EPA," and "may increase the role of the EPA's existing Regional Haze Rule for coal-fired plants in the Eastern Interconnect."[184]

These factors, says Brattle, have resulted in more announcements to retire coal plants: "as of July 2012, approximately 30 GW of coal plant capacity (roughly ten percent of total coal capacity) had announced plans to retire by 2016."[185] Other analyses of the power sector cite to various factors affecting possible closure decisions. For example, M.J. Bradley and Associates, in its recent review of pending coal retirements, concluded that of the 52 GW slated for retirement by 2025, 45 GW will retire by 2016 (Figure 5).[186] It notes that, for the most part, these coal units are:

> *Small in size, lack environmental controls, and are over 50 years old. Most also do not have the capability to burn*

178 It further observed: Assessment areas across the United States report that federal environmental regulations have minimum to no impact on operations and planning for this assessment period. The impacts of recent retirements of fossil-fired generation are reflected in this assessment, and environmental control retrofits are not expected to impact generator outages for the summer peak. Burgess et al, 2013.

179 See GAO Text Box, fn 190.

180 Celebi et al., 2012 at p. 1.

181 Id.

182 Id.

183 Id.

184 Id.

185 Id.

186 Saha, 2013.

Figure 3

Coal Retirements as of March 2013[187]

	Announced for Retirement (Since January 2006) by 2025	Overall U.S. Fleet
Capacity	52 GW	322 GW
Units	340	1264
Unit Age (average)	54 years	43 years
Unit Size (average)	153 MW	254 MW
Utilization (average in 2011)	49%	71%
Regulated (% of capacity owned by vertically integrated utilities)	70%	75%
% with scrubbers (capacity already installed or under development)	9%	59%
Ability to burn western coal (% capacity)	37%	57%

sub-bituminous coal, a cheaper and low-sulfur coal type mined mostly in Powder River Basin, Wyoming.[188]

The Government Accountability Office (GAO) in "Air Emissions and Electricity Generation at U.S. Power Plants," reaches conclusions similar to those reached by M.J. Bradley. GAO also points out that many of the less flexible and older plants likely to retire owing to various factors are those that are disproportionately the most polluting of this class of electric generator.[189] See text box below.

187 Based on Saha, 2013.

188 Id.

189 Trimble & Rusco, 2012.

190 Id. This GAO study is a follow-up to a June 2002 GAO report in which the authors also found that "older fossil fuel electricity generating units" (i.e., those built before 1972) emitted air pollution at higher rates than newer units. See also, Wood, 2002.

GAO Finds Disproportionate Emissions from Older Power Plants [190]

On April 18, 2012 the GAO published a study that looks at air emissions produced by "older electricity generating units," sources GAO defines as having been in operation "in or before 1978." The GAO concluded that "these units provided 45 percent of electricity from fossil fuel units in 2010 but produced a disproportionate share of emissions, both in aggregate and per unit of electricity generated."

Specifically, the GAO found that in 2010 older units contributed, out of all fossil units:

- 75 percent of SO_2 emissions;
- 64 percent of NOx emissions; and
- 54 percent of CO_2 emissions from fossil fuel units.

The GAO also concluded that, for each unit of electricity generated, older units compared with newer collectively emitted about:

- 3.6 times as much SO_2;
- 2.1 times as much NOx; and
- 1.3 times as much CO_2 .

The GAO also observed that there are a number of factors contributing to the difference in emissions between older units and their newer counterparts, including:

- 93 percent of the electricity produced by older fossil fuel units in 2010 was produced by coal-fired units. When compared with natural gas units, coal-fired units create more than 90 times as much SO_2, twice the CO_2, and over five times as much NOx.
- Fewer older units have installed emissions controls:

Units With Emissions Controls

	SO_2	NOx	CO_2
Older	26%	14% (SCR)	38% (no controls) n/a
New	63%	33% (SCR)	6% (no controls) n/a

- Lower emissions among new units are attributable to efficiency improvements in generation technology.

B. Additional Factors

In a review of 20 publications on the topic of plant closures produced between 2011 and 2013, recent literature research conducted at RAP concluded that, with regard to underlying reasons for coal-fired electric generation plant closures, "No sources consulted relied on a single reason as the sole cause for the increase in announced and actual coal-fired electric generation plant closures."[191] Nearly all of the sources consulted agree that new EPA regulations factor into the decisions being made in both structured and restructured markets to close coal plants.[192] However, as discussed below, these sources identified a number of other factors that also affect plant closure decisions.

1. Decreasing Cost of Natural Gas

Nearly every source consulted agrees that the decline in the price of natural gas over the past several years, owing to the availability of shale gas, is making natural gas-fired generation plants more competitive and is a factor in the decision of plant owners to close or idle coal plants.[193] According to EPRI's Victor Niemeyer in a statement made in June 2012, "It's hard to know how much the retirements are based on anticipation of these rules versus gas prices. They all link together."[194] It should be noted, however, that although there are a number of factors that have coalesced to cause the low gas prices, there are a significant number of factors suggesting that these low prices may not be sustainable. While that question is subject to extensive debate, assumptions about gas prices and related risk factors in the context of long-term planning efforts are deserving of serious scrutiny by regulators. Further discussion of natural gas can be found at Appendix One, "Risk and Natural Gas."

2. Underutilized Natural Gas Generation Capacity

There is a significant amount of underutilized natural gas capacity in the United States. According to a 2011 Massachusetts Institute of Technology (MIT) study, the existing U.S. natural gas generation fleet has an average capacity factor of approximately 41 percent, while its design capacity allows such plants to operate at 85 percent.[195] This unused capacity, says MIT, is sufficient surplus to displace roughly one-third of U.S. coal generation.[196]Thus, as the cost of natural gas comes down, gas plants have extra capacity with which to compete economically with certain coal plants and displace them in the dispatch order.[197]

3. Inherent Efficiency of Modern Combined Cycle Natural Gas Plants

Combined cycle natural gas plants are generally more efficient than existing coal plants, with typical heat rates of 7000 BTU/kWh versus 10,000 BTU/kWh, respectively. As their respective fuel costs on a dollars-per-BTU basis converge, more efficient natural gas plants will become more economically competitive than their coal counterparts.[198] Thus, the loss of energy from coal plants that retire can be remedied by the energy produced from currently underutilized gas plants. Capacity lost owing to the closure of coal plants can be made up with demand resources and more efficient and flexible new natural gas units.

4. Increasing Cost of Coal

The increasing cost of coal is adding additional pressure on the ability of U.S. coal plants to participate in U.S. electricity markets.[199] Coal prices have increased every year since 2002, and have done so in part because of increased U.S. exports, particularly to European and Asian markets, and in part because of recent reductions in production in other parts of the world, such as Australia and Indonesia.[200] According to the National Mining Association, U.S. coal exports increased 31 percent from 2010 to 2011, the highest level since 1991.[201] The average price per ton of coal in 2011 was up 24 percent over 2010, and coal exports represented 9.8 percent of all U.S. coal production in 2011.[202]

In addition to coal price increases owing to increased international sales of coal, energy regulators should recognize that there is also some price risk associated with coal that is attributable to pending litigation on the EPA's decision to not make an endangerment finding with regard to emissions

191 Gerhard, 2013.

192 Id.

193 Id.

194 Niemeyer, 2012.

195 Gerhard, 2013.

196 Id.

197 Id.

198 Gerhard, 2013.

199 Id.

200 Id.

201 Coleman, 2012. See also Gerhard, 2013.

202 Id at p. 2.

from coal mines, a source of GHG.[203] In April 2013, the EPA rejected a petition to make an endangerment finding regarding emissions from coal mines.[204] Although currently uncertain, the outcome of this petition could result in the EPA having to develop NSPS for coal mines, which in turn could result in increased costs to that segment of the coal industry.

5. Increasing Cost to Transport Coal

The increasing cost of transporting coal to coal-fired generators raises generator costs and makes them less economical to run.[205] Coal plants receive approximately 72 percent of their coal by rail.[206] Transportation costs can range anywhere from 10 percent to almost 70 percent of the delivered price of coal, depending on the type of coal purchased and location of the power plant.[207] While rail transportation costs increased from $13.04 to $15.54 per ton (19 percent) from 2001 to 2010, in the same time period total delivered coal prices rose from $27 to $40 per ton, almost 50 percent.[208]

6. Age of Coal Plant Fleet

Another factor that weighs into the decision to retire coal plants is that many of the coal plants under consideration are actually at or near the end of their useful lives.[209] These units tend to have higher fixed and variable O&M costs per MWh of electricity generated, to be less efficient in generating electricity, and to be more expensive to retrofit than newer units. As noted in GAO's study, older plants not only are incapable of upgrading for purposes of regulatory compliance, but shutting them down results in a disproportionately (i.e., per MWh) large amount of pollution reduction.[210]

7. Flat and Decreasing Demand

The economic downturn and investment in end-use energy efficiency are combining to flatten load and moderate demand, which lowers potential revenues to generators.[211] Low demand for electricity also lowers electricity prices by reducing the amount of time a relatively inefficient coal plant might otherwise be called upon to operate.

8. Increasing Competitiveness of Renewable Energy

Several commentators have noted indications that the downward trend in the cost of renewable energy is finally reaching the point at which it is placing pressure on coal plants at certain points in the year and replacing some coal plants in the dispatch stack.[212]

9. Poor Load Forecasting

One source cited poor load forecasting as a possibility why some plants may be retired, saying, "[a]s changes in demand and the economy evolved, some utilities acknowledged weaknesses in the forecast models used by the industry to project future electricity use."[213]

C. Conclusions

The previous discussion was intended to illustrate that there are numerous factors affecting coal plant closure decisions, including but not limited to compliance decisions related to newer public health and environmental regulations. It is valuable to see, for example, that a factor like the age and relative efficiency of a coal or gas plant can result not only in owner decisions to discontinue plant operation, but also in an unexpected disproportionate amount of pollution reduction as a result of the closure. The discussion also sought to "drill down" a bit in several of the topics to identify additional factors, for example, the current level of coal exports that could change and in turn have

203 Parrish, 2013. See discussion of endangerment findings and Clean Air Act Section 111.

204 Id. In June 2010, Earthjustice, acting on behalf of WildEarth Guardians, the Sierra Club, and others sent a petition to the EPA invoking Section 111 of the Clean Air Act, and in July 2013, WildEarth Guardians filed suit in the U.S. Court of Appeals for the D.C. Circuit challenging the EPA's refusal to make an endangerment finding regarding GHG emissions from coal mines. See Case No. 13-1212. Id.

205 Gerhard, 2013.

206 U.S. EIA, 2012.

207 Gerhard, 2013.

208 U.S. EIA, 2012.

209 Gerhard, 2013; See also Trimble, 2012.

210 These units provided 45 percent of electricity from fossil fuel units in 2010 but produced 75 percent of SO_2 emissions, 64 percent of NOx emissions, and 54 percent of CO_2 emissions from fossil fuel units. Trimble, 2012.

211 Gerhard, 2013.

212 Id.

213 Id.

material effects on current competitiveness of coal generation vis a vis other sources. Appreciation of the role that these factors, including EPA regulations, play will help regulators as they endeavor to understand generator decision-making and the relative effects of new and pending EPA regulations on generator decision-making.

This discussion is not intended to suggest that the resources replacing coal plants do not bring special challenges with their adoption. States will need to pay attention to overreliance on natural gas and consider alternatives that will help in managing that risk. Reliability must-run policies around the country are also going to "cut the other way" when it comes to coal plant closures.[214] To ensure resource adequacy and system stability in certain load pockets, planners should anticipate the need to continue operating some existing plants longer than might otherwise occur in order to maintain reliability.

214 A "reliability must-run" policy is essentially an exception to a market rule that favors the running of the most economical units first. Under certain conditions, less economical generators are allowed to operate. These conditions might include the need to provide energy or needed voltage support in a constrained area of the system.

IV. Appendix 1: Risk and Natural Gas

A. Introduction

Burning gas instead of coal not only produces less CO_2 (approximately 950 lb/MWh versus 2200 lb/MWh), but it produces fewer other pollutants such as SO_2 and mercury.[215] It also appears generally accepted that gas's increased use for electricity generation and gas's displacement of coal-fired generation is helping reduce current electric sector GHG emissions.[216] For example, Joshua Epel, Chair of the Colorado Public Utilities Commission and Chair of the NARUC Task Force on Environmental Regulation and Generation introduced an April 2013 NARUC webinar entitled "Greenhouse Gas Emissions from Oil and Gas: Estimation, Regulations and Control Technologies," by observing:

> *Estimates of US GHG emissions have shown a marked decrease, and much of the reduction in greenhouse gas emissions is attributable to the substitution of natural gas for coal. However, some have expressed concern with emissions of GHG from the oil and gas sector.*[217]

U.S. DOE Secretary Ernest Moniz similarly highlighted the effects of natural gas on U.S. emissions in a presentation he gave at Columbia University in August 2013, remarking, "In these last years, the natural gas revolution, shall we say, has been a major contributor to reducing carbon emissions."[218]

Although there is no question of a general trend, there are several aspects of natural gas risk — both fuel cost risks and carbon risks — that are worth considering here and keeping in mind as regulators assess the benefits of switching from coal generation to natural gas, and the future role of natural gas-fired electric generation.

B. Cost Risk

Marty Kushler, Senior Fellow at the American Council for an Energy-Efficient Economy (ACEEE) has argued that one "should not make decisions about programs with lengthy multi-year effects based on (2012's) record-low spot market prices for natural gas."[219] Although he is talking about natural gas energy efficiency programs, his observations about the behavior of the natural gas market and its participants is valuable in this context, given the significant role that gas plays in electricity generation markets.

According to Kushler, low spot-market prices of natural gas that were seen in 2012 (i.e., gas priced in the $2.00/Mcf range) were "the result of a 'perfect storm' of unusual circumstances," including:

- Demand destruction from the "Great Recession";
- Shale gas production from early high-production sites and gas dumping;
- Price subsidization of dry gas from high "wet gas" and "liquids" prices;
- The "non-winter" of 2011/2012 (the first four months of 2012 were the warmest January–April in U.S. recorded history);
- Residential and commercial natural gas consumption down more than 18 percent; and
- Gas storage was at record levels, and nearing capacity.[220]

In addition, he maintains that natural gas energy efficiency programs of the past decade have also

215 Natural gas combustion produces significant amounts of NOx.

216 "Current" emissions should be emphasized. Burning gas versus burning coal results in half the CO_2, but that amount of emissions still presents a significant long-term pollution problem. This point was made by Dominion CEO Tom Farrell during a speech in June 2013 at the University of Texas: "The industry will need to go beyond it [i.e., burning gas] to meet the targets of the Kyoto Protocols that call for 80% cuts in emissions by 2050. Replacing every coal plant with new gas and then taking into account demand growth, the industry would emit in 2050 the same amount of CO_2 it does today," Farrell said. Restructuring Today, 2013.

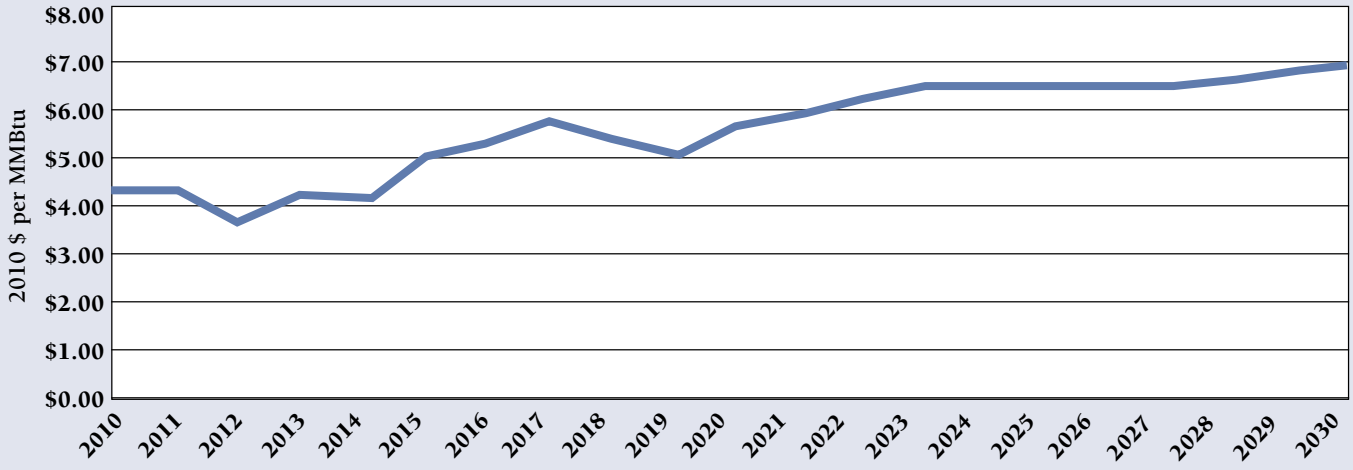
217 Epel, 2013.

218 Moniz, 2013. See also, Politfact.com, 2013.

219 Kushler, 2013.

220 Id.

Figure 4



Gas Prices Will Remain Relatively Low in the Near Term, But Increase as Demand Growth Accelerates

- Natural gas prices will remain relatively low in the near term as continued growth in shale gas production outpaces demand growth.
- However, low gas prices combined with high oil prices will continue to shift E&P activity away from gas and toward oil, thereby slowing the growth in gas production.
- Environmental regulations may accelerate growth in power sector gas use and push gas prices upward.
- After 2020, we project gas prices that stabilize between $6 and $7 per MMBtu, a "happy" medium for both consumers and producers.

Source: ICF International

contributed to the low natural gas prices. ACEEE "modeled the tight natural gas market and demonstrated how a 1 percent drop in demand could produce a 10 percent – 20 percent drop in gas market prices."[221] The "gas price collapse seen in the U.S. gas market in the last few years helps demonstrate that effect…."[222] With effects of the recession in 2008 to 2009, gas demand dropped 1.77 percent in 2009. With shale gas production increasing by 2.5 percent in 2009, gas prices dropped 54 percent, to $3.67/Mcf, from $7.97/Mcf in 2008.[223]

According to Kevin Petak at ICF International, gas prices are expected to stay relatively stable and to increase with demand, moving from $4 to $5 MMBtu in this decade to $6 to $7 MMBtu after 2020.[224] (Figure 4).

It should be noted that the cost of gas is not just the often-quoted Henry Hub price (i.e., just the commodity cost). The full price to deliver gas includes transportation, storage, and distribution costs plus the costs of hedging. According to Kushler, these costs will vary from state to state and system to system, but can be expected to add an additional dollar per Mcf to the cost of the commodity.[225]

Kushler argues that there is not only uncertainty with respect to natural gas prices, but that the uncertainty is not symmetrical: "There is much greater risk on the 'up' side," a significant concern for planning purposes.[226] He notes that this has been the case historically, with effects on the gas market created by such factors as the California Energy Crisis of 2000, severe weather in 2003 and 2006, and high oil prices in 2008 (Figure 5).

In support of this view, there are other indications that low natural gas prices are in for a significant adjustment in the next few years. These "adjustments" will be more than the typical corrections, that is, spikes in cost that occur when prices dip below production costs, as shown in Figure 6. Gas prices will more than adjust; they can be expected to transform if U.S. natural gas markets become sufficiently linked to world markets.

221 Kushler et al., 2005.

222 Id.

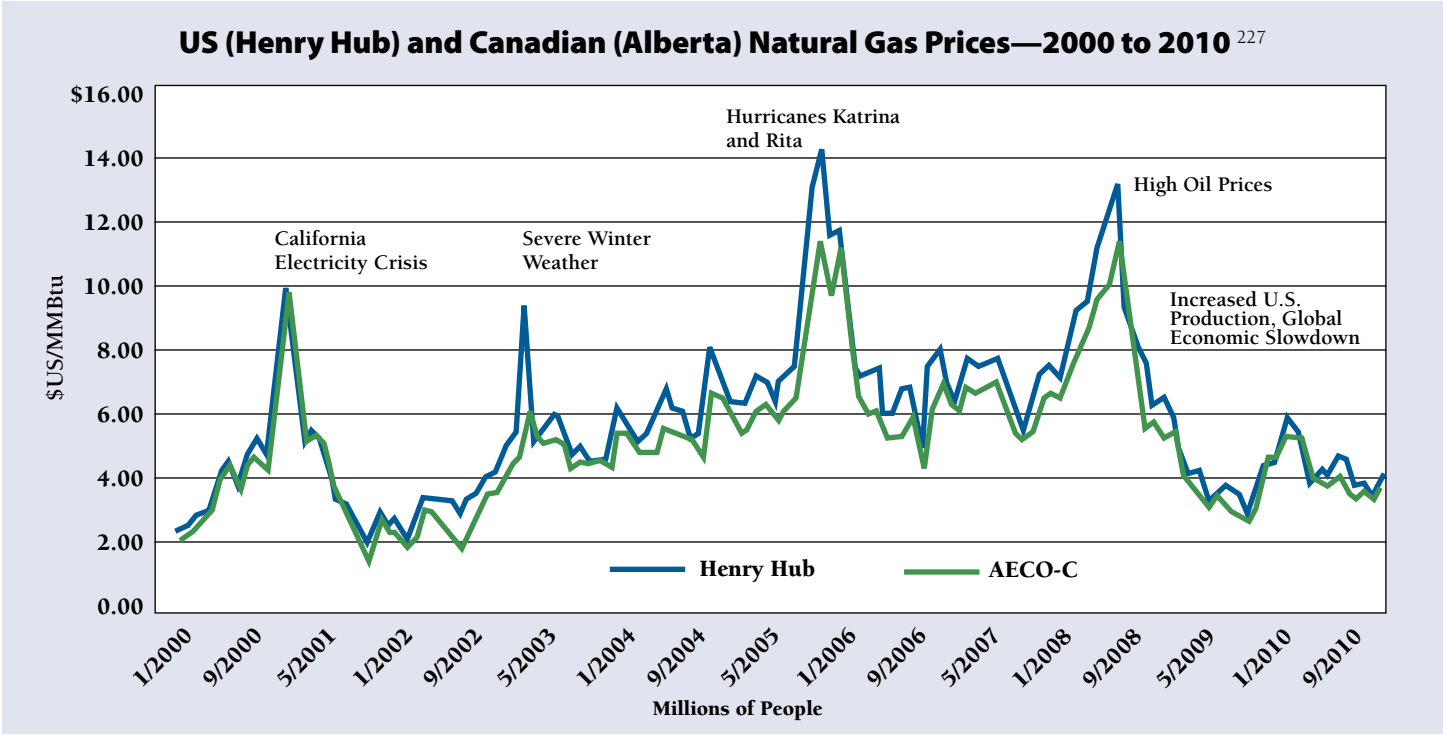
223 Id.

224 Petak, 2011.

225 Id.

226 Id.

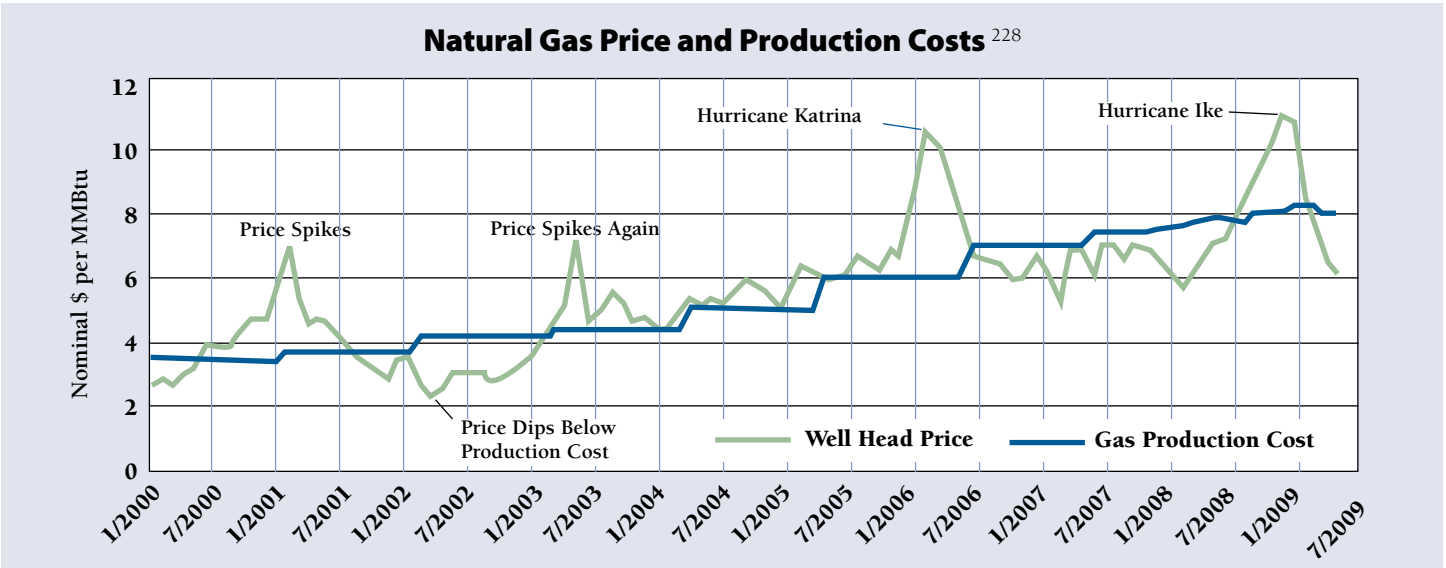
Figure 5



In October 2013 Reuters reported that Exxon Mobil Vice President for Liquefied Natural Gas (LNG), Richard Guerrant, told the World Energy Congress in South Korea that "U.S. natural gas prices are currently below replacement costs because producers are drilling in areas rich in more lucrative petroleum liquids, which subsidize the cost of drilling for the cheaper gas."[229]

Speaking to the same audience, ConocoPhillips Executive Vice President Don Wallette said, "I think there is a misperception out there that with Henry Hub sales

Figure 6

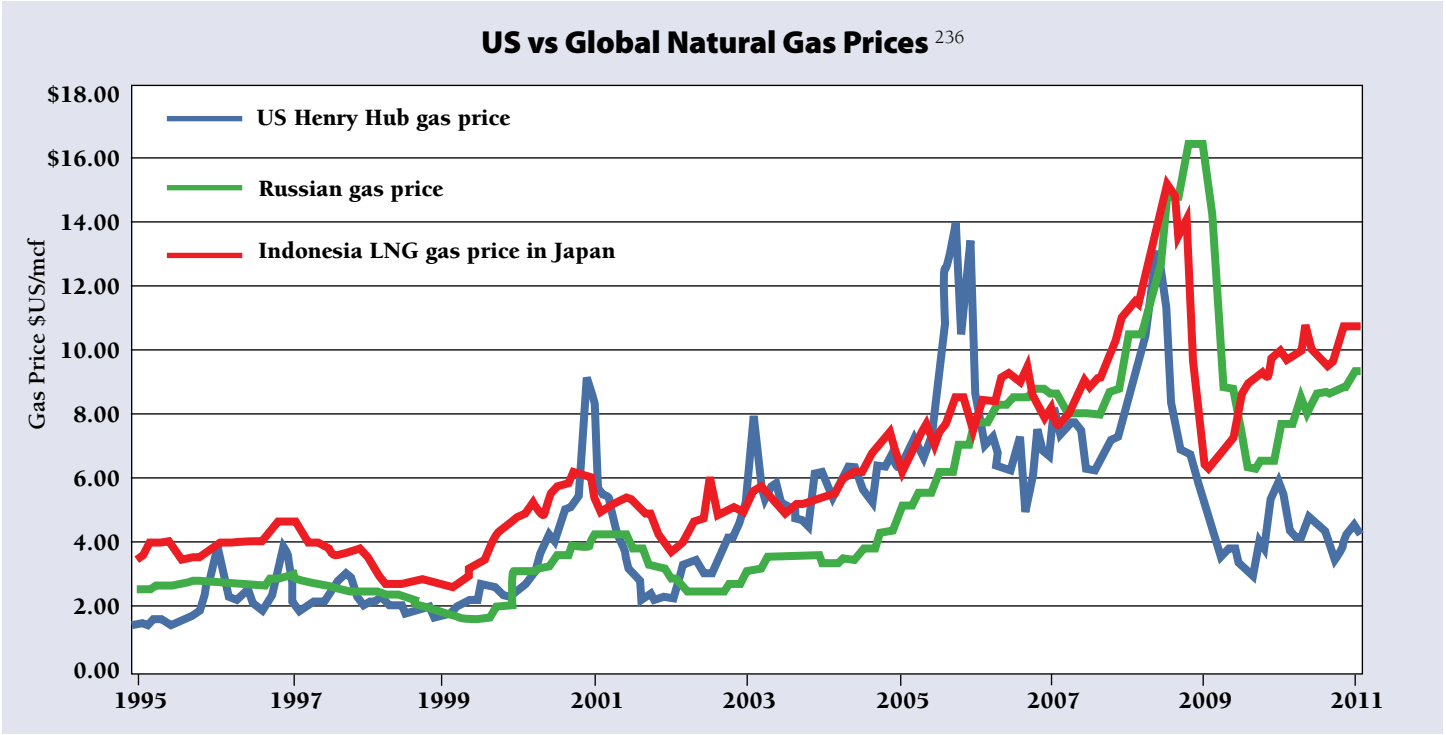


227 Figure 5 shows that natural gas prices over the past 10 years have fluctuated mainly in response to economic and weather factors. Changes in price occurred in response to changes in supply, that is, drilling and closure of wells, and seasonal variations including cold weather, hurricanes, and storage withdrawal and injections. Canadian National Energy Board, 2011.

228 Id. See also Bradley, 2010.

229 Cho, 2013.

Figure 7



from $3.50 we can land LNG in Asia for $11, $12 (per MMBtu)."[230] He added that, "over time the arbitrage is going to be consumed ... and you can expect a convergence of prices." Exxon's Guerrant agreed: "History indicates those low prices cannot be maintained over the long term."[231]

As gas suppliers seek to reassure international investors of the availability over time of the cheaper U.S. commodity, U.S. regulators are clearing the path to greater U.S. natural gas exports and linking of U.S. natural gas to world market prices.[232] According to the Congressional Research Service, "Projects to export liquefied natural gas (LNG) by tanker ship have been proposed—cumulatively accounting for about 41.4% of current gross U.S. natural gas production—and are at varying stages of regulatory approval."[233] In August 2013 the DOE conditionally approved Lake Charles Exports to sell gas to foreign interests, making it the third U.S. terminal to get permission to sell domestic gas overseas.[234] BG Group and Southern Union have similar applications pending at FERC. As of the end of summer 2013, the DOE had 19 pending applications for LNG exportation.[235]

Although international prices (as shown in Figure 9 through examples of Russian prices and Indonesian LNG prices in Japan) have tracked U.S. prices closely, in 2009 there was a divergence in these price levels. In October 2013, European gas was about $11/MMBtu and Asian gas was approximately $16/MMBtu; however, U.S. gas prices were a little below $4/MMBtu – an even more pronounced discrepancy than illustrated in Figure 7. Marty Kushler

230 Id.

231 Id.

232 According to the *Oil and Gas Journal,* "Federal law generally requires approval of natural gas exports to countries with free trade agreements with the US, and a further 'public interest' finding for exports to countries that do not have free trade agreements with the US." Snow, 2013.

233 Ratner et al., 2013.

234 Sabine Pass LNG Terminal in Louisiana and Freeport LNG Terminal in Texas have already received authorization. US Department of Energy (2013).

235 See remarks of Center for Liquefied Natural Gas President Bill Cooper: "For 16 of the 19 pending applications, the comment periods have closed." Snow, 2013. According to the Dallas Business Journal, "A dozen other permits for similar projects are pending at the DOE." Sakelaris, 2013.

236 Kushler, 2013.

refers to this gap as the "Jaws of Delusion," the delusion being that the United States is going to continue living with very cheap natural gas while the rest of the world pays three to four times the price.

According to others, the price for U.S. gas, once equilibrium has been reached with international markets, will not be excessive. Thomas Tunstall, PhD, research director for the Institute for Economic Development at the University of Texas at San Antonio argues in the San Antonio Business Journal that "these new supply markets that extend well beyond U.S. borders will serve to keep a cap on natural gas prices at an estimated $4–$7 per thousand cubic feet [i.e., $3.91–$6.84/MMBtu](and arguably in a tighter range between $5–$6)."[237]

Regardless of where the price settles, the difference between the U.S. market price and market prices elsewhere in the world creates a significant incentive for U.S. producers to move their commodity into global markets, and the potential for domestic prices to reflect the higher prices of those markets.

One last note about price risk: there is a system portfolio risk attributable to what has been referred to generally as gas/electricity interdependence.[238] Although this paper does not go into detail on the topic, it is important to recognize and to consider when reviewing resource alternatives. As the low cost of natural gas produces a larger share of gas-fired electricity production, there will be a risk associated with effects on the electricity system of natural gas price fluctuations. Price spikes could be caused by seasonal demand spikes or storage miscalculations, even if underlying trends for low natural gas prices persist. Portfolio diversification through integrated planning could produce the most likely solutions to this challenge. Solutions would include renewable resources (potentially via a Renewables Portfolio Standard) and aggressive energy efficiency, both electric and thermal (i.e., greater thermal efficiency that results in lower use of natural gas for space heating).[239]

1. Carbon Risk – Global Warming Potential and Leakage

In addition to fuel cost risks, natural gas carries with it carbon risks. Two key aspects of carbon risk are associated with the need for greater precision regarding: (1) the global warming potential (GWP) associated with natural gas, and (2) the actual amount of natural gas that is leaked before it is consumed by end-users like power generators and home owners.

Figure 8

Typical Composition of Natural Gas

Methane	CH_4	70-90%
Ethane	C_2H_6	
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Source: Natural Gas Supply Association

a) Global Warming Potential

The composition of natural gas can vary, but it is primarily methane, as shown in Figure 8.[240] Methane is one of the most significant GHG owing to the amount of it (70 to 90 percent) found in natural gas.

GHG such as methane trap heat in the atmosphere and contribute to global warming. These gases are categorized according to their GWP. GWP represents how much a given mass of a chemical contributes to global warming over a given time period compared to the same mass of CO_2.[241] CO_2's GWP is defined as 1.0. So in order to get a CO_2e for another

237 Tunstall, 2013.

238 NARUC has spent significant time educating its members on various aspects of this issue. See e.g., presentations by van Welie, 2012; Ott, 2013; and Moeller, 2013.

239 In this case, greater thermal efficiency investment would contribute to electric system reliability.

240 According to NaturalGas.org, an educational site developed and maintained by the Natural Gas Supply Association. Available at: http://www.naturalgas.org/overview/background.asp. NaturalGas.org is presented as an educational website covering a variety of topics related to the natural gas industry. The purpose of this website is to provide visitors with a comprehensive information source for topics related to natural gas and to present an unbiased learning tool for students, teachers, industry, media, and government. This site has been created to serve as an informational resource on the many aspects of natural gas.

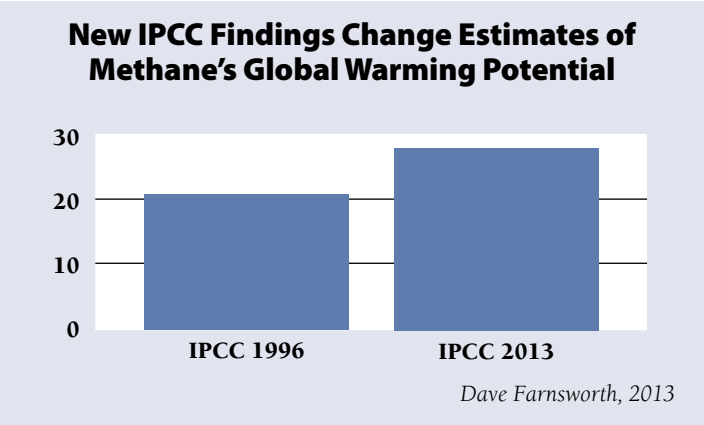
241 U.S. EPA, 2014.

gas, one multiplies the mass of that gas by its GWP value.

The Kyoto Protocol fixed the use of GWP values that were published by the Intergovernmental Panel on Climate Change (IPCC) in 1996 in its Second Assessment Report. The IPCC has updated the values three times since then, in 2001, in 2007, and again in 2013. The EPA has adopted some GWP values on the basis of the IPCC Second Assessment Report: Climate Change (1996) and the IPCC Third Assessment Report: Climate Change (2001). More recently, in September 2013, the IPCC produced a report that characterizes methane as far more potent a GHG than had been previously considered.

The two most important climate impact characteristics of a GHG are how well the gas absorbs energy (preventing it from immediately escaping to space), and how long the gas stays in the atmosphere. Methane is far more efficient than CO_2 at trapping radiation, although its lifetime in the atmosphere is much shorter than CO_2. Currently the EPA relies on a GWP figure for methane that is 21 times greater than CO_2 over a 100-year period. As shown in Figure 9, the GWP figure was taken from the 1996 IPCC report.

Figure 9



In its most recent report made available on September 2013, the IPCC indicated that methane is 28, rather than 21, times stronger a heat-trapping gas than CO_2 over a 100-year time scale.[242] That is a 33-percent increase over the GWP number that the EPA currently uses to calculate the U.S. inventory and apply in its regulatory programs.[243] Continued use of the older numbers significantly downplays the GWP of methane, and will arguably be subject to a correction in the future to better reflect more current thinking on methane's GWP.

b) Natural Gas Leakage

It is unclear as to how much methane leaks during the lifecycle of unconventional gas production and consumption. The leakage rate is unclear, with newer data suggesting anywhere from one to nearly nine percent.[244] Although the overall system leakage trend, according to the EPA, is low, there are individual examples of greater amounts of leakage that call into question overall system numbers. According to a January 2013 article in *Nature,* scientists are reporting on methane emissions from oil and gas fields and "underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system."[245]

> *The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study suggesting that up to 4 percent of the methane produced at a field near Denver was escaping into the atmosphere.*[246]

Leakage rates of this magnitude, noted the article, "could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation."[247] The NOAA/UC Boulder research team

242 U.S. EPA, 2013d.

243 Working Group I – Twelfth Session, Contribution to the IPCC fifth assessment report, climate change 2013: The physical science basis, final draft underlying scientific-technical assessment. (2013, September). pp. 8–58. "When climate-carbon feedbacks are included for both the non-CO_2 and reference gases, all metric values increase relative to the methodology used in AR4, sometimes greatly (Table 8.7, Supplementary Material Table 8.SM.16)." Id. The 2013 draft notes that, where carbon "feedbacks" are taken into account, the GWP for methane increases from 28 to 34 over 100 years, a 61-percent increase over the number the EPA currently uses. Available at: http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_All.pdf. See also, Global Warming Potentials of Ozone Depleting Substances Substitutes. Available at: http://www.epa.gov/ozone/geninfo/gwps.html. Overview of Greenhouse Gases, EPA. Available at: http://epa.gov/climatechange/ghgemissions/gases/ch4.html.

244 Nelsen, 2013.

245 Tollefson, 2013.

246 Id.

247 Id.

found that some of the emissions come from onsite storage tanks, but according to team member Gabrielle Pétron, "A big part of it is just raw gas that is leaking from the infrastructure."[248]

In response to industry officials and others in the scientific community, the NOAA/UC Boulder research team revisited their data and conclusions reported for Colorado. They concluded that their new data, however, support their 2012 conclusions about Colorado, "as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage … 9% of the total production."[249] According to Nature, the nine percent number "is nearly double the cumulative loss rates estimated from industry data – which are already higher in Utah than in Colorado."[250]

According to an earlier (February 2012) article in *Nature,* the America's Natural Gas Alliance has indicated that "the study is difficult to evaluate based on a preliminary review," but added that "the findings raise questions and warrant a closer examination by the scientific community."[251] As noted by Steven Hamburg, chief scientist at the Environmental Defense Fund (EDF), the "NOAA data represent a 'small snapshot' of a much larger picture that the broader scientific community is now assembling."[252]

It is important to recognize that although these data are disturbing, they do not necessarily mean the same level of leakage is occurring across the country. As EDF's Drew Nelson emphasized during NARUC's April 2013 webinar on natural gas, "our use of natural gas will bring with it significant benefits if we recognize the potential risks, including increased GHG emissions, and take steps to minimize them so that the promise of natural gas can be achieved."[253] It is also important to recognize that some states have decided to impose air emissions requirements on natural gas developers. Some requirements are stricter than the applicable federal standards (i.e, NSPS for VOC).[254] For example, Pennsylvania's Department of Environmental Protection (DEP) decided that operators of unconventional gas wells will no longer be unconditionally exempt from seeking an air quality plan approval for well sites. Although the agency may grant such permitting exemptions, operators will need to implement controls and practices more stringent than federal rules.[255] The final revised guidance affords each operator the choice between seeking an air quality plan approval from DEP, or demonstrating and implementing controls and practices more stringent than the federal rules. Practices include leak detection and repair programs for the entire well pad and facility, rather than just the storage vessels as required by federal rules.

There is substantial uncertainty about the continued cost and GHG advantages of natural gas. Regulators should be cautious in assuming that inexpensive natural gas will be able to solve all of these emerging environmental regulatory problems.

248 Id.

249 Id.

250 Id.

251 Id. Tollefson, 2012.

252 Id.

253 Id.

254 As mentioned at note 85 and accompanying text, while not regulating GHG associated with natural gas production, the EPA regulates that sector's emissions of VOCs under NSPS Subpart OOOO. Note also that states can further regulate emissions associated with natural gas production. See e.g., the State of Colorado's proposal to require companies to use infrared cameras and other methods to check for leaks of methane and VOCs from storage tanks, pipelines, and other sources of emissions. Colorado Department of Public Health and the Environment, 2013.

255 Sunday, 2013.

Appendix 2: Additional Alternatives to the RCRA Subtitle C or D Approaches

In the CCR rule, the EPA is also considering additional alternatives to the Subtitle C or D approaches. These are briefly characterized below.[256]

- An approach referred to as "D Prime" would provide for continued operation of existing surface impoundments until the end of their useful life. Other requirements would be the same as under Subtitle D.
- An alternative in which "wet-handled" CCRs are regulated under Subtitle C and "dry-handled" CCRs under Subtitle D.
- An approach that would impose Subtitle C regulations unless a state develops enforceable Subtitle D regulations and submits them to the EPA for approval. In that case, if a state were to fail to develop a program within two years or if the EPA did not approve one within one year, the federal Subtitle C rule would become effective in that state.
- An approach that follows Subtitle D requirements unless there were finding of egregious violations of the requirements. In that case CCRs would be considered "special wastes" and treated pursuant to Subtitle C.

256 Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, 2010.

Appendix 3: A Closer Look at GHG Permitting[257]

A. Background

Under the Clean Air Act's PSD program, stationary sources that emit more than 100 or 250 tons per year (depending on the type of source) of "any air pollutant" must obtain a permit before beginning construction on or making major modifications to any "major emitting facility." Facilities subject to PSD requirements must use Best Available Control Technology (BACT) for each pollutant emitted by the facility that is "subject to regulation" under the Act. Title V operating permits are also required for all major sources of air pollution, and include all Clean Air Act requirements for a source in a single document.

As explained below, the final Tailoring rule set the thresholds for Steps 1 and 2 of a phase-in approach to regulating GHG emissions under the PSD and Title V Operating Permit programs.[258] In mid-2012, the EPA issued a final rule with regard to Step 3 of the Tailoring Rule, and in early 2013 started steps to develop what could become Step 4.

Step 1

- PSD requirements apply to sources' GHG emissions if the sources:
  - Were subject to PSD *anyway* (anyway sources) owing to their non-GHG-regulated air pollutants; and
  - Emit (or have the potential to emit) at least 75,000 tons per year (tpy) CO_2e.
- Title V requirements apply to:
  - Existing sources with Title V permits; or
  - New sources obtaining Title V permits that are required to address GHG emissions in those permits as necessary.

Step 2

- PSD applies to the largest GHG-emitting sources that are:
  - Not *anyway* sources, and that are
  - Either new sources that emit (or have the potential to emit) at least 100,000 tpy CO_2e, or
  - Existing sources that
    - Emit at least 100,000 tpy CO_2e, and that
    - Undertake modifications that increase emissions by at least 75,000 tpy CO_2e, and also
    - Emit at least 100/250 tpy of GHG on a mass basis.
- Title V applies to existing sources that are not "anyway" sources and that emit (or have the potential to emit) 100,000 tpy CO_2e.

Step 3

On June 29, 2012, the EPA issued a final rule (Step 3) retaining the GHG permitting thresholds established in Steps 1 and 2 that are used to determine when PSD and Title V operating permits are required for new and existing industrial facilities.[259] The EPA also determined at this time not to apply PSD and Title V permitting to smaller GHG emissions sources because, according to the EPA, permitting authorities are still in the process of developing permitting infrastructure and expertise, and also identifying opportunities to develop more streamlined approaches to permitting.

The EPA, however, has streamlined certain permitting approaches allowing for the use of "plantwide applicability limitations" (PALS) and their application on a CO_2e basis in addition to the already available mass-basis. A PAL emissions limit can be applied across a source rather than at specific emissions points. This allows a source to make changes within a facility without necessarily triggering PSD

257 Prevention of significant deterioration and title V greenhouse gas tailoring rule step 3, GHG plantwide limitations and GHG synthetic minor limitations, 2012.

258 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 2012.

259 Prevention of significant deterioration and title V greenhouse gas tailoring rule step 3, GHG plantwide limitations and GHG synthetic minor limitations, 2012. See also, Parker, 2013.

permitting requirements as long as aggregated emissions do not exceed the PAL. Step 3 also revises the existing PAL regulations to allow for a source that emits or has the potential to emit at least 100,000 tons per year of CO_2e, but that has minor source emissions of all other regulated New Source Review pollutants, to apply for a GHG PAL while still maintaining its minor source status.

Step 4

In response to concerns over the potential cost of investing in BACT to small emissions sources such as commercial buildings and hospitals, the EPA is further considering alternative compliance approaches. In February 2013, "Inside EPA" reported that Anna Marie Wood of the EPA's Office of Air Quality Planning and Standards told a February 26 meeting of the Clean Air Act Advisory Committee's permits panel that energy efficiency could be a realistic GHG control option for smaller sources, and that the agency is considering whether or not it could satisfy potential permit mandates.[260] At the Clean Air Act Advisory Committee, Wood indicated that the EPA is gathering information to support a Step 4 tailoring rule that might be issued in April 2016.

260 U.S. EPA, 2013c.

Appendix 4: The CWA in Brief

The CWA (or Act) establishes a comprehensive program for protecting the nation's waters. The Act prohibits the discharge of pollutants from a point source to waters of the United States, except as authorized under the CWA. Discharges, however, may be authorized through a NPDES permit.

The Act authorizes the EPA to establish national technology-based effluent limitations guidelines and standards (ELGs) for categories of industrial dischargers that are based on the degree of control that can be achieved using various levels of pollution-control technology.

It also authorizes the EPA to promulgate nationally applicable pretreatment standards that restrict pollutant discharges from facilities that discharge wastewater indirectly through sewers flowing to POTWs.

Pretreatment standards are typically designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment.

Direct dischargers must comply with effluent limitations in NPDES permits, while indirect dischargers must comply with "pretreatment" standards.

Technology-based effluent limitations in NPDES permits are derived from effluent limitations and NSPSs promulgated by the EPA, or based on best professional judgment where the EPA has not promulgated an applicable effluent guideline or NSPS.

Additional limitations based on water quality standards (developed at the state level) are also required to be included in the permit in certain circumstances.

The EPA promulgates national ELGs for major industrial categories for three classes of pollutants:

- **Conventional pollutants**
  Total suspended solids, oil and grease, biochemical oxygen demand, fecal coliform, and pH
- **Toxic pollutants**
  Toxic metals (e.g., arsenic, mercury, selenium, and chromium)
  Toxic organic pollutants (e.g., benzene, phenol, and naphthalene)
- **Nonconventional pollutants**
  Pollutants not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids)

Appendix 5: Section 111(d)

(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which

(A) establishes standards of performance for any existing source for any air pollutant

(i) for which air quality criteria have not been issued or which is not included on a list published under section 7408 (a) of this title or emitted from a source category which is regulated under section 7412 of this title but

(ii) to which a standard of performance under this section would apply if such existing source were a new source, and

(B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410 (c) of this title in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title with respect to an implementation plan.

In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.

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