TABLE OF CONTENTS

APPENDIX F 2

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

Office of Commissioner Philip D. Moeller

August 1, 2011

The Honorable Lisa A. Murkowski
United States Senate
Washington, DC 20510

Dear Senator Murkowski:

Thank you for your continuing interest in our work at the Federal Energy Regulatory Commission (FERC). As described in your letter to me, I raised the issue of how actions of the Environmental Protection Agency (EPA) could impact the reliability of our nation's electric system at the Commission's September 2010 open meeting, and I have been deeply interested in how our staff has been communicating with both the public and within government on this issue of critical importance to our nation. Thus, I share your concern about ensuring that we maintain a reliable and affordable supply of electricity.

Given these concerns, I have long-stated that I can be "fuel neutral" but I cannot be "reliability neutral". That is, I can be neutral as a regulator with regard to how competitive markets ultimately decide which types of power plants are most efficient and affordable, regardless of whether those power plants are fueled by water, natural gas, fuel oil, uranium, coal, wind, the sun, or any other fuel. But I cannot be neutral about the reliability of our electricity.

The Federal Power Act provides this Commission with statutory responsibilities over certain reliability matters. For that reason, the Commission has engineering staff in its Office of Electric Reliability that is dedicated to the topic of electric reliability, and many other Offices at the Commission have engineering and technical staff with expertise on that topic. Thus, I believe that this Commission can play an important role in providing information to the EPA on the extent to which its proposed rules will have an impact on electric reliability.

Given that you've sent similar letters to my fellow Commissioners, my answers could differ from their responses. Yet I think that should be expected, as we are individuals with potentially different views on this matter.

Thank you for asking these questions. Here are my answers:

Question 1. *With respect to the impact on electric reliability of the listed EPA rules affecting generation of electric power, please list and describe the Commission's actions taken; studies conducted; assistance provided to any other agency, including EPA; collaborative efforts with any other agency; and provision of data to any other agency.*

Answer: Concerning the impact of the listed EPA rules on electric reliability, the Commission has not acted or studied or provided assistance to any agency, including EPA. Because this answer may not be expected, I wish to clarify that the Commission acts mostly through orders in individual proceedings, although it sometimes issues reports, or holds conferences for the public, or acts in other ways.

While the Commission itself may not have acted, individual Commissioners can express their opinions, as can the staff of the Commission. I have been informed that our staff has provided assistance to other federal agencies on this topic, and that the staff has been studying various impacts of EPA proposals on energy markets. Such assistance by staff is not binding upon the Commission, and can take place without the knowledge of all or some Commissioners. The relationship of the Commission to its staff is described in the Code of Federal Regulations, and includes the following:

> The Commission staff provides informal advice and assistance to the general public and to prospective applicants for licenses, certificates, and other Commission authorizations. Opinions expressed by the staff do not represent the official views of the Commission, but are designed to aid the public and facilitate the accomplishment of the Commission's functions. Inquiries may be directed to the chief of the appropriate office or division. 18 CFR Section 388.104(a).

In addition, the Commission has "delegated authority" to several individuals on its staff. That delegated authority often extends only to matters that are unopposed or of a noncontroversial nature.[1]

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[1] *See* 18 CFR Section 375.301(c); 18 CFR Section 375.303(b); 18 CFR Section 375.307(b); 18 CFR Section 375.308(x); 18 CFR Section 375.315(b). And for a general discussion of staff's relationship to Commission action, *see, Obtaining Guidance on Regulatory Requirements,* 123 FERC ¶ 61,157, at PP 30-34 (2008).

Question 2. *Regarding collaborative efforts between FERC and EPA described above, has an Inter-Agency Task Force been established? If so, please state or provide:*

a. *the date it was established;*
b. *the source of its authority;*
c. *a copy of its charter;*
d. *a description of the scope of its work;*
e. *a schedule of its meetings, including a list of its meetings to date and any planned meetings;*
f. *any minutes of its meetings; and*
g. *a list of the agencies and agency officials participating.*

Answer: I do not believe that the meetings that have been held between staff in the Office of Electric Reliability and EPA constitute an Inter-Agency Task Force as described in the subparts of your question.

Question 3. *Please describe all work being jointly performed by FERC staff, including work done in collaboration with EPA – whether in connection with an Inter-Agency task force or otherwise – regarding the potential impact of EPA regulations on the retirement of electric generating units and, to the extent such information has been developed, the specific type and characteristics of units that may face retirement as a consequence of such regulations.*

Answer: Based upon the information that I received from staff in the Commission's Office of Electric Reliability (OER), staff has shared public information with EPA, provided information to EPA on the types of studies that would be needed to address reliability concerns, and provided EPA with a set of questions about EPA's analytical results so that staff could better understand an ICF model that was used by EPA. Staff in OER told me that they made an effort not to create an impression that the Commission either endorses or disagrees with the study performed by EPA. According to OER staff, EPA's reliability analysis has been limited to generation adequacy assessments for 2015. EPA's analysis is apparently limited to the expected retirements caused by two of its rulings (does not include coal residuals, green house, clean water, and others). According to the information that I received from Commission staff, they have pointed out to EPA that a reliability analysis should explore transmission flows on the grid, reactive power deficiencies related to closures, loss of frequency response, black start capability, local area constraints, and transmission deliverability.

In addition, and also based upon the information that staff has told me, staff has indicated to EPA that the regional transmission planners would be best suited to run these studies. Commission staff has suggested that EPA interact with the ongoing initiatives at the grid operators known as "PJM" and "MISO" which are assessing the effect of projected retirements on their grids. Commission staff informed me that they believe that EPA needs to interact with regional transmission planners to determine the issues that may affect the regional grids, especially during the transition period when plants are retired and others are shut down to retrofit their facilities.

According to Commission staff, the ICF model used by EPA is a pipes and bubbles tool which assumes transmission deliverability is not an issue within the region. The ratings of the pipes (transfer limits) are apparently determined by consultants who analyze available transmission planning studies, historical OASIS postings and linear analysis. Based on the rating of the pipes, OER staff understands that the tool determines if firm transfers can be delivered from region to region as well as capacity additions needed to meet target reserve margins. OER staff believes that the ICF model does not consider certain reliability issues. According to OER staff, the ICF model could provide a potential scenario of the generation mix available in future years. OER staff believes that a transmission requirements study would still be needed to develop a transmission expansion plan for the potential generation mix that may result from the ICF tool.

Question 4. *Please describe FERC's efforts to explain the effect of potential retirements on electric reliability. If research, data, or analysis has been developed by or supplied to FERC, please provide it. If no analysis has been conducted, please explain why.*

Answer: The Commission has not engaged in efforts to explain the effect of potential retirements on electric reliability. The Commission has not issued any reports, orders, held a conference, or taken any action on this matter. While the Commission itself has not taken action, individual Commissioners have expressed their opinions. In that regard, on May 3, 2011, I discussed this matter with Gina McCarthy, Assistant Administrator for the Office of Air and Radiation, and some of her staff. On October 28, 2009, at Chairman Wellinghoff's invitation, I participated in a meeting with EPA, White House, Department of Energy, and others at a meeting with the White House Council on Environmental Quality.

While the Commission has not acted on this matter, the staff of the Commission has expressed its opinions. In response to why the Commission has not performed an "analysis", I believe that the Commission should consider whether it should issue a report containing a formal Commission analysis. If the Commission decides against the issuance of an analysis, then at minimum, the Commission should direct its staff to use its expertise to perform an analysis of the EPA's rules that could impact reliability of electricity --- and disclose that analysis for public comment --- and then hold a technical conference for public input.

Question 5. *Please describe fully FERC's powers to protect electric reliability in the event of plant retirements, and what measures FERC plans to take to ensure electric reliability or an explanation of why such measures have not been devised. Please provide the following assessments, or an explanation of why such assessments have not yet been devised:*

a. *an assessment of generation adequacy in the face of retirements of significant generating units in transmission-constrained areas;*
b. *an assessment of the effect of retirements of generating units in organized markets for energy and capacity (e.g. on prices and unit commitment); and,*
c. *a general assessment of the capacity to permit and construct new electric generation units in a timely manner such that electric supplies form retired plants are replaced and anticipated demand growth is met.*

Answer: To the extent that measures to ensure reliability have not been devised by Commission staff, then the Commission should direct its staff to develop such plans and take such measures. Given the importance of electric reliability, such plans and measures should be developed in an open process with opportunity for input from the general public.

Question 6. *The Clean Air Transport Rule specifically lists ensuring electric reliability as a "key guiding principle." Please describe any research, documentation or analysis FERC has provided EPA for this rule.*

Answer: To my knowledge, the Commission has not provided EPA with any research, documentation, or analysis of the Clean Air Transport Rule. However, individual Commissioners or the Commission staff may have provided their own opinions to EPA. I believe that the Commission should consider whether it should direct its staff to issue a report to the Commission on the Clean Air Transport Rule.

Question 7. *Regarding the Commission's FY 2010 Performance and Accountability Report to Congress, quoted above, and the staff analysis of electric reliability impacts referenced in the quotation, please describe or provide:*

a. *the study and all supporting materials including research;*
b. *a list of any other agencies involved in the production of the study with information on their involvement*
c. *actions FERC has taken or plans to take based on the study; and*
d. *how and where the study has been made public, or why it has not been released*

Answer: I believe that the Chairman will describe staff's work on this topic when the Chairman sends his response to you.

Question 8. *In your view, would compliance with EPA or other environmental regulations excuse a violation of FERC-approved electric reliability standards? If so, should the Commission refrain from imposing penalties for these violations?*

Answer: In my view, compliance with EPA or other environmental regulations would not necessarily excuse a violation of FERC-approved reliability standards. Every individual case should be addressed on its merits. For example, instead of excusing reliability standards, perhaps in some cases compliance with FERC-approved reliability standards should excuse non-compliance with EPA regulations. As stated above, I can be "fuel neutral" but I cannot be "reliability neutral".

Question 9. *Please assess whether FERC has sufficient statutory authority to protect electric reliability in collaboration with other federal entities that are undertaking rulemakings.*

Answer: At this time, the Commission seems to have sufficient statutory authority to protect electric reliability against actions that might be taken by EPA --- given my assumption that EPA, if provided with accurate information, will take actions that appropriately balance the importance of reliable electric supply against its statutory obligations. To assist the EPA, this Commission already has authority to issue reports, hold conferences, and seek information from the public on the reliability impacts of contemplated EPA rules. In addition, this Commission can describe the reliability impacts of the actions contemplated by the EPA by making appropriate submissions in the various rulemakings that are in process at EPA.

My views are shaped by the complexity and cost associated with shutting down a power plant --- and my concern that EPA be able to accurately model that process as part of its decision making. If a power plant is retired with inadequate notice, electricity can become less affordable and less reliable. Before a power plant is retired, the operator of the transmission grid must consider how to provide reliable electricity without that plant as part of the network.

A numerical example shows how cost and reliability need to be considered when a power plant is retired. That is, the operator of the transmission network could determine that a power plant can be retired only after utilities invest $50 million into upgrading the transmission system. Since they are long-lived transmission assets, those $50 million in assets would be expected to be in-service for some fifty years, which means that they would cost customers roughly $1 million a year (ignoring interest and present value). But in the interim, the power plant owner would be entitled to recover its costs of remaining open even after it had decided to shut its plant down. That cost could be $50 million to customers for one year of service --- a cost that could have been avoided had the $50 million in transmission upgrades been in service. Thus, while the transmission upgrades might only cost about $1 million each year for fifty years, the $50 million paid by consumers in one year to keep a plant open could make the retirement more costly than necessary. And this example doesn't even consider the cost of building a new power plant to replace the power that will be unavailable with the shut down.

In addition to this example, please see my concluding thoughts below, where I describe the recent plans to close certain generating units in the Philadelphia area that are known as Cromby and Eddystone.

Question 10. *Is FERC or any other agency, to your knowledge, soliciting or relying upon advice or assistance from any entity established pursuant to the Federal Advisory Committee Act?*

Answer: No, not to my knowledge.

Concluding Thoughts

I greatly appreciate your decision to send me these questions. Not only have you raised the visibility of this important issue, but your inquiry has prompted the Commission staff to better inform me on this topic.

- **The Critical and Complex Role of Reliability**

The recent and enduring heat wave that simultaneously impacted a large portion of the population of the United States underscores the essential and life-saving importance of electric reliability. With economic weakness and closed factories throughout the nation, you might have expected the available power plants to easily handle the heat wave. Yet the operators of the power grid relied on all of their available resources, including coal plants that are expected to be shut down because of EPA decisions, in order to ensure the reliability of the grid and the health and safety of the public.

My consistently expressed concern with EPA rulemakings has been the potential for a negative impact on reliability. I believe the system can absorb significant retirement of older coal-fired, oil-fired and natural gas-fired generation units. But it absolutely must be done in an orderly manner that does not impact our health and safety.

- **Timing of EPA Regulations and Utility Planning Horizons**

The timing of the EPA regulations does not conform to the relevant planning horizons in the electric sector of our economy, one of the most capital-intensive sectors of industry. Transmission lines and power plants are often planned over a ten-year period, and in consideration of the long-lived nature of assets that are expected to be in service for more than forty years. Compounding this situation is the fact that the United States has several distinct wholesale markets for electricity, including different types of markets that are broadly categorized as bilateral markets (covering many western and southeastern states) and organized markets (including markets in Texas, California, and many Midwestern and eastern states).

The rules for these electricity markets are not standardized. For reliability purposes, this exacerbates the challenge of conforming to EPA rules. Each region has different standards for planning for new power plants and transmission lines, and different standards for retiring an existing power plant. Thus, EPA and Commission staff must ensure that their analysis of reliability impacts is applicable in all regions of the nation, not just one or two.

In addition, some of the organized markets hold auctions of electric capacity three years in advance of the time when such capacity is needed. These auctions are generally designed to ensure that adequate generating capacity will be built when it is needed three years in the future. Other markets are considering equivalent types of "forward" capacity markets for the same reasons. A three-year advance cycle of generation procurement does not align with the EPA rules, as bidders into these markets may not know whether they can submit bids for all of their power plants, or if some of their power plants will need to retire within the next three years because of EPA regulations.

Prior to the most recent heat waves this summer, several studies concluded that the nation has enough excess capacity to absorb the retirement of surplus power plants. We should all be able to agree that surplus power plants can be retired if the remaining power plants are located where they can replace the power that will no longer be available. But looking at this issue from the perspective of the minimum number of power plants that is absolutely necessary doesn't answer the question of where power plants must be located. An older coal plant in a specific location may not provide a lot of energy to the grid, but it may be in a location with access to transmission lines or where its voltage support is critical for reliability.

- **The Cromby-Eddystone Example**

I have often cited the retirement of two electricity generating plants in the area surrounding Philadelphia as an example of how EPA air rules could impact the reliability of specific pockets of electricity load. In December 2009, Exelon provided notice to PJM of its intent to deactivate the Cromby and Eddystone units --- four fossil-fired generating units located in Southeastern Pennsylvania, all of which had operated for more than fifty years. Cromby Unit No. 1 is a 144 MW coal-fired unit; Cromby Unit No. 2 is a 201 MW peaking unit that is fueled by gas or oil. Eddystone No. 1 and No. 2 are both coal-fired units with a capacity of 279 MW and 309 MW, respectively.

Upon receipt of Exelon's notice, PJM conducted a deactivation study and determined that Cromby Unit No. 2 and Eddystone Unit No. 2 would be needed past their planned deactivation date to manage localized reliability issues pending completion of transmission system upgrades. Specifically, unless 18 identified transmission upgrades totaling $44 million were constructed and placed into service, the study revealed that the retirement of these generating units could have an adverse effect on reliability. Some of these upgrades were placed in-service earlier this year and the last of these upgrades are expected to be completed by June 2012.

As part of its obligation to ensure just and reasonable rates, the Commission conducted a proceeding that would determine the amount of compensation that would allow Exelon to recover its costs if it decided to keep the units operational. In that proceeding, Exelon explained that in 2009, the two generating units realized negative pre-tax cash flow of approximately $28 million when selling capacity, energy, and ancillary services at market rates. Exelon anticipated that future cash flows would be significantly negative because the units would require costly project investment to maintain their operability and because their dispatch would be limited due to environmental restrictions. Moreover, the generating units failed to clear in their regional capacity auctions, demonstrating that Exelon's costs to operate the units as capacity resources exceed the market price for capacity.

The proceeding settled prior to a formal hearing and the Commission ruled that the generating units could collectively charge customers about $82 million to continue operating before the transmission upgrades entered service.[2] The financial implications of at least this situation are clear: in order to retire these units, customers will pay at least $44 million for transmission upgrades, to be collected over the next forty to fifty years, and customers will also pay some $82 million to Exelon so that the power plants will be available for about a year, to be collected over the next year or so.

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[2] As provided in the settlement, Eddystone Unit No. 2 received a twelve-month contract term, and Cromby Unit No. 2 received a seven-month term. If the transmission upgrades do not enter service on the expected date, the settlement provides for Exelon with an opportunity for additional compensation. *See* application of Exelon Corp. in FERC Docket No. ER10-1418, and Commission orders issued on September 16, 2010 and May 27, 2011: *Exelon Generation Co., LLC,* 132 FERC ¶ 61,219 (2010) *and Exelon Generation Co., LLC,* 135 FERC ¶ 61,190 (2011).

- **Better Data on Unit Retirements Now Available**

The uncertainty over proposed EPA rules has already impacted capacity markets. As described briefly above, some capacity auctions are held three years in advance. In PJM, the most recent (2011) forward capacity auction for 2014/2015 revealed that an increasing amount of generation from coal-fired plants is at risk of retirement; as 14% less capacity from coal plants cleared the auction when compared to the 2010 auction. PJM predicts that this trend of coal-fired generation retirements will continue into 2012 for its 2015/2016 auction.

PJM's RTO-wide capacity price for 2014/2015 substantially increased by 354 percent from the prior year's auction results. Increased prices in the PJM-West region showed much less price separation than in prior years from the PJM-East region. The rise in PJM-West capacity prices reflects the fact that, due to economic weakness, there are now fewer transmission constraints and congestion on the grid, which in turn allows for more affordable power to flow from west to east.

- **Recommendations**

Not only do I suggest that you and your Committee continue to follow and examine this issue, I respectfully offer several recommendations.

In speaking with reliability experts, one consistent recommendation is that the EPA needs to be involved in regional market stakeholder meetings where system planning is undertaken. Only then can EPA fully appreciate the location-specific impacts of its actions. I have heard from our Office of Reliability that EPA has not been involved to date.

In addition, I believe the federal government needs to convene an open and transparent process to assess the reliability implications of the EPA rules individually and in aggregate. EPA seems a natural choice, given that their rules would be the topic of the process. The Commission may also be a natural choice, given our responsibility for electric reliability. Regardless of which part of government convenes this open and transparent process, I would recommend that the North American Electric Reliability Corporation (NERC) be a major participant in any such process. Given the time constraints imposed by the courts on EPA, perhaps this process should have been initiated long ago. In any event, the feasibility of any court-imposed timeline is, at a minimum, worthy of consideration by Congress.

My answers to your questions also contain several recommendations. In response to question 4, I said that the Commission should consider whether it should issue a report containing a formal Commission analysis of potential retirements on electric reliability. If the Commission decides against the issuance of an analysis, then at minimum, the Commission should direct its staff to use its expertise to perform an analysis of the EPA's rules that could impact reliability of electricity --- and disclose that analysis for public comment --- and then hold a technical conference for public input.

And in response to question 5, I said that to the extent that measures to ensure reliability have not been devised by Commission staff, then the Commission should direct its staff to develop such plans and take such measures. Given the importance of electric reliability, such plans and measures should be developed in an open process with opportunity for input from the general public.

In response to question 6, I said that the Commission should consider whether it should direct its staff to issue a report to the Commission on the Clean Air Transport Rule.

- **Documents**

I am not providing documents responsive to this request at this time, as I will first have my personal staff review the documents that Commission staff is providing to you. If after that review I discover that I have additional documents in my possession that I believe are responsive, I will provide them to you.

- **Conclusion**

Finally, the impact of retiring power plants can be cushioned by making it easier to build the transmission lines that are needed to move power to customers. By building needed transmission, we can maintain the reliability of our nation's transmission network, while simultaneously improving consumer access to lower-cost power generation. Plus, a well-designed transmission network can allow efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power. I am always willing to express my thoughts on legislative changes that could ease the difficult process of building transmission.

I have no doubt that this nation is capable of retiring a substantial proportion of older and less efficient power plants that produce a disproportionate amount of air emissions. Nor do I doubt that power plants which emit too many pollutants should be eventually retired. But these retirements must be done in an orderly manner that does not threaten the reliability of electricity, which in turn affects our public health and safety.

Sincerely,

Philip D. Moeller

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF THE COMMISSIONER

August 1, 2011

The Honorable Lisa A. Murkowski
United States Senator
Committee on Energy and
Natural Resources
Washington, D.C. 20510-6150

Dear Senator Murkowski:

Thank you for your letter of May 17, 2011, and for the opportunity to share with you my thoughts on these important issues.

With regard to questions 1-7, I have no further information to add to the responses provided by Chairman Wellinghoff and Commissioners Norris and LaFleur, and by Commissioner Moeller, in their letters dated August 1, 2011. However, with respect to questions 8, 9 and 10, I wish to separately set forth my own views regarding the relationship between the Federal Government and users, owners, and operators of the bulk electric system.

Regulated public utilities are obligated to serve electricity ratepayers. Congress assigned to FERC authority with respect to the reliability of the bulk electric system in 2005. The United States has superb records in both environmental protection and electric reliability. I remain committed to ensuring the reliable operation of our Nation's electric grid. Reliable service of electricity is essential to the health, welfare, and safety of the American people and necessary to serve our economy. However, I recognize that environmental protection laws and regulations are important to the well-being of our Nation as well.

Question 8 highlights the problem of an entity ensnared in the dilemma of conflicting laws or regulations. I have not researched whether compliance with an EPA regulation could excuse a violation of a FERC-approved reliability standard and I have not reviewed, nor do I comment on, the authority of the United States Department of Energy to address these issues. However, the users, owners and operators of the bulk-electric system should not be compelled by their government to choose between compliance with environmental laws or with FERC-approved reliability standards. Put differently, regulated entities should not have to elect which agency's penalty they would rather face. Requiring public utilities to make such a Hobson's choice does not serve consumers and, frankly, is not good government.

But I also believe that both the regulated and the regulators can and must do more to ensure that regulated entities do not find themselves in the position of having to make a Hobson's choice. First, FERC and the EPA need to be proactive to ensure that reliability concerns are considered and addressed in any analysis by the EPA of its environmental regulations affecting utilities. To this end, I recommend that FERC and the EPA continue their dialogue but in a more formalized and expansive fashion. Given the integrated nature of today's society, such coordination would ensure that the EPA will not enforce its rules in a vacuum.

Second, the electric industry recognizes its obligation to comply with both environmental regulations and FERC-approved reliability standards and to plan their systems to reliably serve consumers while complying with environmental requirements. In the first instance, the regulated entity, with better knowledge of its operations and requirements, should seek to harmonize how it will meet the various regulatory requirements it faces. It must have adequate time to do that.

Finally, I suspect it will be the rare situation when a regulated entity finds itself, notwithstanding adequate planning, in a position of having to choose between compliance with one regulator's rules over another's. In that instance, however, it should be the duty of the regulators to work together, and with the regulated entity, to find a resolution that best assures reliable operation of the electric grid and compliance with environmental standards.

I thank you very much for inquiring as to the relationship between affordable and reliable electricity service and environmental regulation. I hope the foregoing discussion has been responsive to your letter, and I invite any further questions or comments on this critical topic.

Sincerely,

Marc Spitzer
Commissioner
Federal Energy Regulatory Commission

August 23, 2010

VIA ELECTRONIC MAIL TO: a-and-r-docket@epa.gov

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Nos. EPA-HQ-OAR-2002-0058 and EPA-HQ-OAR-2006-0790

Re: *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters*, 75 Fed. Reg. 32006 (Jun. 4, 2010); *National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, Proposed Rule*, 75 Fed. Reg. 31895, 31900 (June 4, 2010).

Dear Ladies and Gentlemen:

The National Mining Association ("NMA") submits these comments in the two above-referenced dockets, hereafter, respectively, the proposed "Boiler MACT" rule and the proposed "Area Source" rule. NMA is a national trade association of mining and mineral processing companies whose membership includes the producers of most of the nation's coal, metals, industrial and agricultural minerals; the manufacturers of mining and mineral processing machinery, equipment and supplies; and the engineering and consulting firms, financial institutions and other firms serving the mining industry.

I. Introduction

NMA member companies, along with the manufacturing and other industrial customers they supply, provide fuel to and operate industrial boilers and process heaters to generate steam and electricity. Extractive industries, energy intensive industries and the manufacturing sector continue to face severe economic conditions that impact millions of high-wage jobs. NMA supports policy decisions that will lead to economic growth and recovery, create jobs, encourage technological advancement and result in air quality improvement. The proposed Boiler MACT standards, however, are far more stringent than needed to protect human health and the environment from hazardous air pollutant (HAPs) emissions from industrial boilers. EPA is afforded the discretion, and maintains the technical justification, to ease the burden of these proposed regulations on the economy while adequately protecting health and the environment.

NMA offers the following comments on the proposed Boiler MACT and Area Source rules. In addition, as discussed in more detail below, NMA believes that the regulatory analysis supporting the proposed rules is fatally flawed because it fails to take into account the cumulative impact of all of EPA's now-numerous completed, pending and expected rulemakings that are intended to and will have the effect of substantially reducing the usage of coal in the United States. These rulemakings include those affecting the use of coal for electric generation, where EPA is implementing a coordinated program to create, in its words, a "clean, efficient, and completely modern power sector," those affecting the use of coal for industrial, commercial and institutional purposes, such as the two rules specifically at issue here, and those directly affecting coal mining.

All of these rulemakings together will produce a dramatic and cascading series of effects not only in the coal industry but throughout the economy. There will be direct effects on coal employment and indirect effects on employment generally in the economy as a result of higher energy prices. Higher energy prices will also affect GDP and economic activity generally. American competitiveness will also be affected, as higher prices undermine the ability of American business to compete, with resulting off-shoring of American business and jobs.

Impact analysis performed by EPA now proceeds on a rulemaking-by-rulemaking basis, as if one rulemaking is unconnected to the next and as if the regulatory consequences are not cumulative. As a result, EPA's impact analyses mask the cumulative effect of the Agency's overall regulatory program. Individual-regulation impact analyses often predict limited effects, when in truth the compounding effects of the overall program may produce extremely large consequences.

This Balkanized approach to impact analysis impairs the public's right to notice and comment regarding EPA regulation. For instance, EPA's Regulatory Impact Analysis for the Boiler MACT rule shows relatively minor effects, which might lead the public to believe that the rule is relatively innocuous. Cumulative analysis, on the other hand, is likely to lead to a far different conclusion—that coal usage will decline dramatically as a result of the combined effect of numerous EPA rulemakings with attendant serious economic consequences. Armed with that information, the public would likely provide significantly different comment on the rule. EPA and other cooperating agencies rely upon similar cumulative impact assessments when analyzing proposed federal actions subject to the National Environmental Procedure Act, and the public should be afforded the same opportunity here.

Analyzing cumulative impacts is not just good policy, it is required by Executive Order 12866 and the notice and comment rulemaking provisions of the Clean Air Act ("CAA"). NMA therefore urges EPA to defer final action on the two rules at issue here until the necessary cumulative impact assessment is produced. The specific type of analysis that NMA recommends is set forth as an attachment to these comments.

II. EPA Must Produce a Cumulative Impact Analysis of Its Regulatory Program Affecting the Use of Coal

A. Cumulative Analysis Is Needed

1. EPA's coordinated regulatory agenda to reduce coal usage

EPA has undertaken a far-reaching regulatory program that is apparently designed to reduce the use of coal throughout the American economy. The coordinated nature of this program is most evident in the electric power sector, which EPA has undertaken to transform. Upon taking office, the EPA Administrator formulated seven priorities, one of which was to "develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable reduction goals for SO_2, NO_2, mercury and other air toxics."[1] This goal was reiterated by EPA in its recently proposed Transport Rule, where the Agency said that "[i]n furtherance of this priority goal, and to respond to statutory and judicial mandates, EPA is undertaking a series of regulatory actions over the course of the next 2 years that will affect the power sector in particular."[2]

These EPA rulemakings include:

- The recently completed National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("SO_2") and nitrogen dioxide ("NO_2");
- The currently proposed new ozone NAAQS and the soon-to-be-proposed new $PM_{2.5}$ NAAQS;
- The proposed Transport Rule and expected additional transport rules for the 1997 ozone NAAQS;
- The soon-to-be-proposed MACT standards for electric generating units ("EGUs");
- EPA's greenhouse gas ("GHG") regulation under the Prevention of Significant Deterioration ("PSD") program;
- The soon-to-be-proposed New Source Performance Standards for EGUs (including GHG NSPS);

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[1] *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator's January 12, 2010 outline of the Agency's seven priorities.

[2] *Id.*

- Best Available Retrofit Technology ("BART") standards for EGUs;

- The proposed regulations for coal combustion residues; and

- The soon-to-be-proposed water quality regulations for cooling intake structures and soon-to-be-proposed effluent guidelines for discharges from power plants.

Recognizing that all of these regulations are implementing a single overall priority goal and constitute a "comprehensive set of requirements,"[3] EPA pledged to coordinate at least its power sector air quality regulations and, to the extent it could under relevant statutory law, to coordinate these power sector air quality regulations with the coal combustion residue regulations and the two power sector water quality regulations.[4] EPA further pledged to "engage with other federal, state and local authorities, as well as with stakeholders and the public at large, with the goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds, resulting, in turn, in the creation of a clean, efficient, and completely modern power sector."[5]

EPA's regulatory agenda for the power sector will almost certainly significantly reduce the use of coal for electric generation. While EPA so far has not done any study of the cumulative impact of these regulations on coal use (or otherwise), the contractor EPA uses to model impacts of individual regulations recently produced its own analysis showing that just the EGU MACT standards alone will force major retirements of coal-fueled power plants.[6] Forced retirements will have substantial negative economic impacts nationally, but will also have severe impacts locally, as exemplified by the Arizona Hopi and the Navajo Generation Station:

> "Scott Canty, the Hopi Nation's general counsel, explained to a panel of lawmakers on Nov. 2 that closure of the Navajo Generating Station would cripple the tribal government. The Hopi Nation relies heavily on coal revenues to fund its government, Canty said. About 88 percent of the tribal government's budget comes from revenue generated by coal-fired energy production at the Navajo Generating Station, Canty said. . . . The EPA has proposed rules that would require the power plant to install expensive emissions equipment to address visibility impairment issues at the Grand Canyon. But the plant's

[3] *Id.*

[4] *Id.*

[5] *Id.*

[6] *Id.*

> owners and the tribes argue that the retrofit is too costly."[7]

Moreover, news accounts recently reported that EPA is well aware that its regulatory efforts in the power sector will increase the costs to coal-fueled EGUs and make them less competitive with renewable resources. In an article entitled "Administration Eyes EPA Rules To Spur Shift From Coal To Renewables," it was reported that:

> Rob Brenner of EPA's Office of Air & Radiation told a July 28 meeting of the agency's environmental justice advisers that pending rules to control emissions, waste and water discharges from utilities will not only protect public health but add costs to the industry that might make renewable energy a more viable alternative.
>
> "We need to set health-based standards for power plants, and once we do that then they can compete with some of these renewable sources," Brenner said at the National Environmental Justice Advisory Committee (NEJAC) meeting in Washington, DC. He added later, "It's not really a fair competition because [coal-fueled power plants] are cheaper than they should be because they're not controlling their pollutants" to their full extent because EPA is yet to issue key rules for the sector, including a mercury air rule and a plan to regulate coal combustion residue.[8]

The same article reported that the White House also understands that transforming the power sector will inevitably result in reduced use of coal and increased use of renewables. Referring to remarks of Nancy Sutley, Chair of the White House Council on Environmental Quality, the article reported that:

> Sutley responded that she doubts the existence of so-called clean coal. "Other people have labeled it 'clean coal,'" she said. "I don't know if I would necessarily concede that that is real. . . . I think in the long run, not just for the [United States] but for the world, that

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[7] Luige del Puerto, *Hopi Nation in Arizona appeals for help as coal plant face disclosure,* ARIZ. CAP. TIMES, Nov. 3, 2009, *available at* http://www.allbusiness.com/government/government-bodies-offices-regional/13389633-1.html.

[8] *Administration Eyes EPA Rules to Spur Shift from Coal to Renewables*, InsideEPA.com (July 29, 2010), *at* http://insideepa.com/201007291915893/EPA-Daily-News/Daily-News/administration-eyes-epa-rules-to-spur-shift-from-coal-to-renewables/menu-id-95.html.

> developing and making sure that there is access to these inherently cleaner sources of energy is important. . . . . We need to use energy more efficiently and more cleanly."[9]

Other EPA regulatory proposals are also part of an overall strategy to reduce the use of coal throughout the economy. This strategy includes the Boiler MACT and Area Source rule at issue here. In the regulatory preamble to the Boiler MACT rule proposal, EPA stated forthrightly that its reason for proposing strict MACT standards for coal boilers and process heaters but only work practice standards for natural gas boilers was to incentivize operators of coal-fueled boilers to switch to natural gas and to discourage operators of natural gas-fueled boilers from switching to coal.[10] In discussing this issue, EPA made plain that it considers coal to be a "dirty" fuel whose use is inconsistent with the CAA and therefore should be discouraged.[11] In contrast, EPA considers natural gas to be a "clean fuel" whose use should be encouraged at coal's expense. According to EPA:

> In addition, emission limits on gas-fueled boilers and process heaters may have the negative effect of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (i.e., coal).[12]

The coal industry also faces a panoply of prospective regulation of the process of producing coal. These regulations include potentially stricter NAAQS for PM_{10} which may make western surface mining untenable, new restrictions in Appalachia that could result in major reductions in coal mining in that region, and potential imposition of NSPS standards on mining emissions of PM_{10}, methane, volatile organic compounds, and nitrogen oxides. All of these regulations together—EPA's power sector regulations, its regulations for the use of coal in the manufacturing and commercial sectors, and its regulations of coal mining—all have the potential to combine to cumulatively and dramatically reduce coal usage.

2. The effect of each EPA individual rule affecting coal, including the rules at issue here, cannot be understood without a cumulative analysis

Given EPA's intent to transform the power sector from what it is today into something different and given its efforts to reduce coal use throughout the economy, EPA must produce a cumulative and economy-wide assessment of this

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[9] *Id.*

[10] *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, 75 Fed. Reg. 32,006, 32,025/3 (June 4, 2010).
[11] *Id*.

[12] *Id.*

program. As EPA has proposed and finalized each individual regulation, EPA's impact analysis has been limited to the effect of the specific regulation in question. However, to understand the effect that all the rules together will create, it is necessary to study the effect of that program in total.

These effects could be extremely large. For instance, EPA projects the annual cost of the SO_2 NAAQS to be $2.9 billion to $3.0 billion in 2020, with most of those costs associated with the power sector[13]; the annual cost of the Transport Rule (all in the EGU sector) to be $3.7 billion in 2012 and $2.8 billion in 2014,[14] with another $2 billion in 2020 and 2025[15]; the annual cost of the ozone standard to be $32 – 44 billion, again with much of that cost in the EGU sector[16]; and the total costs of the coal combustion residue rule to be over $8 billion under the Subtitle D option and over $20 billion with the Subtitle C option.[17] Despite the request from NMA and others for EPA to assess the cost of its GHG regulatory program, EPA has refused to do so, and so that cost is unknown but could be very substantial as well. The other programs identified above will also add significant cost, with the new EGU MACT standards expected to have a very large impact.

But these estimates, as large as they are, mask the overall effect of the regulations when considered cumulatively. The proposed Transport Rule is an example. EPA's draft Regulatory Impact Analysis ("RIA") for this proposed rule envisions relatively small impacts to coal usage. EPA projects that EGUs can meet the requirements of the rule by switching from high sulfur to low sulfur coal and by installing pollution control equipment, with the result that EPA estimates the retirement of only 1.2 GW of "small and infrequently used" coal-fueled generating units by 2014.[18] Based on the foregoing, EPA projects additional cost to the utility industry of $3.7 billion in 2012 and $2.8 billion in 2014 ($2006).[19]

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[13] U.S. Environmental Protection Agency, *Final Regulatory Impact Analysis (RIA) for the SO2 National Ambient Air Quality Standards (NAAQS)* at 7-4, Table 7.1, June 2010 (Docket ID EPA-HQ-OAR-2009-0769-0059).

[14] 75 Fed. Reg. at 45348/1.

[15] *Id*. at 45333, TableV.E-1.

[16] U.S. Environmental Protection Agency, *Final Ozone National Ambient Air Quality Standards (NAAQS) Regulatory Impact Analysis* at 5-23, March 2008 (Docket ID EPA-HQ-OAR-2005-0161-2849) (estimate for 0.065 ppm standard; EPA's proposal is 0.060-0.070).

[17] *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities*, 75 Fed. Reg. 35218, 35134, Table 1 (June 21, 2010).

[18] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Proposed Federal Transport Rule* at 14, June 2010 (Docket ID EPA-HQ-OAR-2009-0491-0078).

[19] *Id*. at 31.

NMA will comment on these projections in its comments on the proposed Transport Rule, but for purposes here EPA's projection of almost no impact to the coal industry is not meaningful because it is based on an analysis of the Transport Rule in isolation. Thus, even if EPA's projected assessment of the effect of the Transport Rule on coal is correct, that assessment assumes that there are no other forthcoming EPA regulations that will affect the use of coal, an assumption that is clearly wrong. The control options that the Transport Rule RIA envisions appear to exhaust (and likely go beyond exhausting) the ability of the power sector to absorb EPA regulation without large-scale closings of coal plants. The next regulation following the Transport Rule that adds cost to coal-fueled electric generation therefore will force plant closings, but it is incorrect to say that it was that next regulation and not the Transport Rule that causes the plant closings. Both rules and indeed the entire program cause that effect.

EPA's push for replacement of coal with natural gas in the national electricity generation mix, as discussed above, will have severe economic impacts. The American Public Power Association recently published a study evaluating the economic impact of relying more heavily on natural gas to generate electricity.[20] It provides insights into the potential cumulative economic impacts of the numerous recent rulemakings, proposed rules and forthcoming proposals that focus on coal-based electricity generation. According to the study, the total cost of replacing all existing coal generation with gas would be $743 billion. The study estimates that the cost of just replacing the existing 335,000 MW of coal-based generation would cost $335 billion. The need for new pipeline and storage capacity would be another major hurdle to this fuel switching and the study estimates this would cost $348 billion. The remainder of the total costs would entail necessary changes in the way natural gas is managed in the U.S. energy system, investment in training new staff to deal with the fuel changes, among other changes in power support structure.

EPA itself recognizes the need for cumulative analysis in an analogous situation. EPA requires that EPA reviewers of Environmental Impact Statements ("EISs") under the National Environmental Protection Act ("NEPA") take cumulative impacts into account, including consideration of "impacts that are due to past, present, and reasonably foreseeable actions."[21] According to EPA, in assessing environmental impacts, it is necessary to assess "[t]he combined, incremental effects of human activity" rather than just the impacts of the particular action for which federal approval is sought.[22] This is based on the recognition that individual actions "may be insignificant by themselves," but that cumulative impacts accumulate over time,

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[20] Nicholas Braden, *New Study Examines Economic Impacts on Utilities if Carbon Emission Rules Cause Shift from Coal to Natural Gas* (Amer. Pub. Power Assn., Wash., D.C.), July 7, 2010 (news release).

[21] U.S. Environmental Protection Agency, *Consideration of Cumulative Impacts in EPA Review of NEPA Documents* (May 1999) at 10.
[22] *Id*. at 1.

from one or more sources and these cumulative effects must be taken into consideration.[23]

The Council on Environmental Quality ("CEQ") also requires cumulative impact analysis in EISs. CEQ regulations require that agencies considering major actions that could affect environmental quality consider the "overall, cumulative impact of the action proposed (and of further actions contemplated)."[24]

EPA's and CEQ's reasons for requiring cumulative impact analysis in EISs apply with equal force to economic analysis that EPA performs of its regulations. Where effects of a proposed action accumulate with those of other related actions, examining the effects of the proposed action in isolation will mask the overall effect of the action. That is as true for EPA's regulatory efforts to reduce coal usage as it is for environmental analysis in the NEPA context. To again cite the proposed Transport Rule as an example, as stated, EPA concludes that the rule will not materially affect the use of coal for electric generation.[25] But under the rationale of CEQ's NEPA regulations, cumulative impact analysis should be conducted because "[c]umulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[26]

The same is true for EPA's analysis of the proposed Boiler MACT rule specifically at issue here. EPA's RIA concludes that the rule will have only relatively minor effects on production costs for the sectors of the economy affected. But EPA's analysis is rudimentary and only takes into consideration increased engineering costs and does not examine (at least so far as NMA can tell) fuel-switching. Yet, as stated above, the rule is designed to encourage coal boilers to fuel-switch to gas and to discourage gas-fueled boilers from fuel-switching to coal. Moreover, the proposed rule is just one of a series of rules apparently designed to reduce coal use in the United States. Even if the boiler MACT in and of itself did not significantly affect coal usage (a conclusion that cannot be drawn from the face of the RIA), that result may be masking a much larger effect on coal usage when seen in context of EPA's

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[23] *Id*.

[24] 35 Fed. Reg. 7390, 7391 (1970). It should be emphasized that CEQ does not distinguish between cumulative analysis of environmental impacts and of socioeconomic impacts. Under CEQ regulations, agencies must examine the effect of the proposed action on the "human environment." 40 C.F.R. § 1508.14 states that "[h]uman environment" shall be interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment." While "economic or social effects are not intended by themselves to require preparation of an environmental impact statement," "[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." This applies to cumulative analysis: where socioeconomic effects accumulate from multiple actions, they must be assessed cumulatively, just as environmental effects must be assessed cumulatively. Thus, cumulative analysis is as relevant for examining socioeconomics as it is for analyzing environmental impacts.

[25] 75 Fed. Reg. at 45357/1.

[26] 40 C.F.R. § 1508.7.

overall program. Discerning whether that overall effect exists is the central purpose of cumulative impact analysis and the reason why such analysis is required in EISs.

B. EPA's Failure to Conduct a Cumulative Analysis Ignores Executive Order 12866 and Violates the CAA

Cumulative analysis does not just make good regulatory sense; it is legally required. Two separate authorities require cumulative analysis here.

1. Executive Order 12866

Executive Order 12866 specifically requires cumulative analysis as follows:

> Each agency shall tailor its regulations to impose the least burden on society, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable*, the costs of cumulative regulations.*[27]

This requirement for cumulative analysis stems from the regulatory philosophy of Executive Order 12866 that the need for and effects of government regulatory actions should not be examined in isolation but instead on an overall and coordinated basis. The preamble to the Order found that the then current regulatory system did not work in a way that produced efficient results or regulations that were "effective, consistent, sensible, and understandable."[28] The first objective of the Order, therefore, was to "enhance planning and coordination with respect to both new and existing regulations."[29] In that vein, the main administrative provisions of the Order—an interagency Planning Mechanism, the requirement that each agency produce a Unified Regulatory Agenda and develop a Regulatory Plan, the requirement for a Regulatory Working Group and the provision for quarterly Conferences among OIRA and state, local and tribal governments—were all included to enhance coordination of any specific regulation proposed by an agency with that agency's other existing and contemplated regulations, with other regulations of other agencies, and with the President's overall regulatory priorities.[30]

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[27] Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993) (emphasis added).

[28] *Id*.

[29] *Id*.

[30] *Id*.

The Statement of Regulatory Philosophy and Principles in Executive Order 12866 also stressed the need for coordination. This Statement provides that "[i]n deciding whether and how to regulate, agencies should assess *all* costs and benefits of available regulatory alternatives."[31] Agencies are instructed to "examine whether existing regulations (or other law) have created, or contributed to, the problem that a new regulation is intended to correct and whether those regulations (or other law) should be modified to achieve the intended goal of regulation more effectively"[32]; to "base its decisions on its best reasonably obtainable scientific, technical, economic, and other information concerning the need for, and consequences of, the intended regulation"[33]; and to "avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations or those of other Federal agencies."[34] Indeed, the preamble to the Executive Order states that "[t]he objectives of this Executive order are to enhance planning and coordination with respect to both new and existing regulation…."[35]

This requirement for coordinated government action based on coordinated and cumulative analysis built on the same requirement in Executive Order 12291, the predecessor order to Executive Order 12866 and the Order which first required agencies to prepare Regulatory Impact Analyses. Executive Order 12291 required agencies, in promulgating new regulations, to "tak[e] into account the condition of the particular industries affected by regulations . . . *and other regulatory actions contemplated for the future*."[36]

The Executive Order 12866 requirements for coordinated and cumulative analysis apply with particular force to EPA's efforts to remake the power sector and its apparent effort to reduce coal usage throughout the economy. As shown above, each individual regulation that EPA promulgates in this area, including the Boiler MACT rule and Area Source rule at issue here, is part of a single overall program with cumulative consequences.

Moreover, EPA cannot say that cumulative analysis is not "practicable" within the meaning of section 1(b)(11) of Executive Order 12866. EPA obviously has very sophisticated modeling techniques at its disposal. If in any one rulemaking EPA believes that it cannot anticipate and therefore assess the effects of future rulemakings, EPA can assess a range of possible future regulation. Certainly, the fact that EPA has indicated that it has an overall program in furtherance of one of the Agency's seven priorities suggests that EPA has a fairly concrete idea of the

[31] *Id*. (emphasis added)
[32] *Id*. at 51735-36.

[33] *Id*. at 51736.

[34] *Id*.

[35] *Id*. at 51735.

[36] Exec. Order No. 12,291 at § 2(e) (emphasis added).

range of regulatory outcomes that it anticipates. Alternatively, EPA can delay any particular rulemaking until it has better information about future regulatory requirements that it intends to impose. What EPA cannot do, however, is to follow its current regulatory course, where the Agency analyzes individual rulemaking effects in isolation, as if there is no overall regulatory context.

2. CAA

Cumulative impact analysis is also legally required under the rulemaking provisions of the CAA where, as here, EPA has undertaken coordinated and comprehensive regulation of the power and coal sectors through a series of related rulemakings. The purpose of these CAA rulemaking provisions is both to ensure good regulatory outcomes and to protect the public's right to have adequate notice of the need for and effect of EPA regulatory action so that the public can provide meaningful comment.

In this context, section 307(d)(3) of the CAA requires that a rule be accompanied by a statement of its basis and purpose, including "the major legal interpretations and *policy considerations* underlying the proposed rule."[37] For the reasons discussed above, an underlying policy consideration of the Boiler MACT rule and Area Source rule at issue here is EPA's overall intent to incentivize reductions in coal usage and increases in resources that EPA considers to be "clean." That being the case, EPA must provide an analysis of the consequences of this policy so that the public can comment adequately. As stated, the coal industry and public at large might have an entirely different view of these proposed rules if EPA produced a cumulative assessment rather than the narrow assessment reflected in the RIA.

The U.S. Court of Appeals for the D.C. Circuit has stated that "[i]t is not consonant with the purpose of a rulemaking proceeding to promulgate rules on the basis of inadequate data, or on data that, [in] critical degree, is known only to the agency."[38] Unless the public knows the overall consequences of EPA's regulations in context of other related regulations, the public's right to provide adequate comment is compromised.

Additional support for cumulative analysis is found in section 318 of the CAA, which requires that the Administrator undertake an analysis of the cost of complying with various EPA actions, including rulemakings under section 111(d). Under section 318(d), such analyses "shall be as extensive as practicable" consistent with the standards set forth in that provision.[39]

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[37] 42 U.S.C. § 7607(d)(3) (emphasis added).

[38] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 373, 393 (D.C. Cir. 1973), *cert. denied* 417 U.S. 921 (1974).

[39] 42 U.S.C. § 7617(d).

C. The Specific Cumulative Impact Assessment Requested

NMA believes that the cumulative impact assessment should examine the following factors:

- Overall impacts on the economy. Specifically, the effect on GDP and jobs. In this regard, some of EPA's regulations (in particular, the NAAQS) will not just affect energy but will affect other sectors of the economy as well both directly (for example, through direct regulation of manufacturing sources) and indirectly (for example, through increased energy costs). EPA should examine all reasonably foreseeable effects of its regulations on the overall economy.

- Energy. This part of the analysis should include impacts on energy production and usage, energy shortages, energy costs, including fuel costs and retail electricity prices, and energy employment should be determined. Changes in the energy mix in the United States should be shown over time, including electric capacity additions and reductions by fuel type. Employment and energy cost impacts should be estimated for each energy sector.

- Competitiveness. This part of the analysis should include impacts on industrial and manufacturing production and competitiveness. EPA should determine the impacts of regulation on cost of production and employment in the relevant sectors, and the extent to which production and jobs will be reduced as a result of higher costs and foreign competition.

- Study design. Scenarios should be constructed for a business-as-usual case (without adoption of the contemplated regulations) and a case where EPA adopts the contemplated regulations. Additional scenarios may be included to test the findings under different appropriate assumptions. Where EPA regulation does not directly regulate but instead requires states to adopt regulations meeting EPA standards (for instance, EPA regulation under the NAAQS program and NSR/PSD program), EPA should estimate state regulatory responses, using a range if necessary. All assumptions, analytical methods and underlying data (or appropriate citations to data sources) should be provided. All impacts should be broken down on a state-by-state basis. Regulations included in the study should not be limited to just those listed in NMA's comments but should include any other EPA regulations that EPA believes will affect the nation's economy, production and usage of energy and manufacturing.

III. The Proposed Standards are Far More Stringent Then Necessary to Protect Health and the Environment

A. EPA Should Identify More Subcategories of Coal-fueled and Specialized Industrial Boilers

Section 112(d)(1) of the Clean Air Act (CAA) states that, in promulgating regulations establishing emission standards for major sources, the "Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." Section 112(c)(1) also states that, while "categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to Section 111 of this title," nothing in that statement "limits the Administrator's authority to establish subcategories under this section, as appropriate."

In coal-fueled industrial boiler units, testing has clearly indicated that coal rank has a significant effect on the emission levels of HCl and mercury. Low-rank coals such as lignite and sub-bituminous coals have higher moisture levels and lower carbon and energy levels, whereas high-rank coals such as bituminous and anthracite colas have lower moisture levels and higher carbon and energy levels. These qualities of the various types of coal have a direct effect on the resulting HCl and mercury emissions of the boilers that use them as feedstock. Therefore, pursuant to Section 112(d)(1), multiple subcategories should be created in the coal-fueled industrial boiler category based upon the particular type of coal combusted by the unit.

Furthermore, industrial boilers that have specialized uses and are therefore operated less frequently should be listed in a separate subcategory. Such auxiliary boilers are often operated primarily during plant startups, and as such emit very low levels of HAPs. These boilers should be categorized as those with a 10 percent capacity factor for the maximum hourly heat input, and should be subject to a work practice standard under Section 112(h) of the CAA.

B. The "Pollutant By Pollutant" Approach to Determining MACT is Not Appropriate Because it Results in Standards That Do Not Reflect the Performance of the Best Performing Boilers

The proposed Industrial Boiler MACT standards are based on pollutant-by-pollutant analyses that rely on a different set of best performing sources for each separate HAP standard.[40] In other words, EPA has "cherry picked" the best data in setting each standard, without regard for the sources from which the data come. The result is a set of standards that reflect the performance of a hypothetical set of best performing sources that simultaneously achieve the greatest emission reductions for each and every HAP rather than the actual performance of one or more real sources. This "Frankenstein" approach[41] is contrary to the language of § 112 and produces unrealistic and impracticable standards.

The statute unambiguously directs EPA to set standards based on the overall performance of *sources*. Sections 112(d)(1), (2), and (3) specify that emissions

[40] *See, e.g.,* 75 FR 32019 ("For each pollutant, we calculated the MACT floor for a subcategory of sources by ranking all the available emissions data from units within the subcategory from lowest emissions to highest emissions, and then taking the numerical average of the test results from the best performing (lowest emitting) 12 percent of sources.")
[41] *Industry Faults Strict EPA MACT Method for Regulating "Best" Sources*, Inside EPA's Clean Air Report, Sept. 3, 2009.

standards must be established based on the performance of "sources" in the category or subcategory and that EPA's discretion in setting standards for such units is limited to distinguishing among classes, types, and sizes of sources. These provisions make clear that standards must be based on actual sources, and cannot be the product of pollutant-by-pollutant parsing which results in a set of composite standards that do not necessarily reflect the overall performance of any actual source. Congress provided express limits on EPA's authority to parse units and sources for purposes of setting standards under § 112 and that express authority *does not* allow EPA to "distinguish" units and sources by individual pollutant as is proposed in this rule. *Sierra Club v. EPA*, 551 F.3d 1019, 1028 (D.C. Cir. 2008).

Even assuming for the sake of argument that the Agency does have discretion to depart from a source-wide approach to standard setting, EPA has improperly exercised its discretion in this rule. EPA has failed to provide an assessment of how many existing boilers and process heaters will be able to meet the proposed standards without taking any further control measures – *i.e.*, EPA has not shown or attempted to show that the proposed standards reflect the performance of any actual affected sources. This failure to investigate a fundamental aspect of the proposed rule renders the rule arbitrary and capricious.

EPA's database shows that very few units are best performers for more than one pollutant. As a result, the record demonstrates that the proposed standards reflect the performance of exceedingly few actual sources. Thus, even if EPA had investigated the consequences of using a pollutant by pollutant approach, it could not have reasonably concluded that the proposed standards reflect the performance of actual sources. Of the approximately 2,000 sources within EPA's inventory of solid, liquid, and gas 2 boilers, based on the emissions data in EPA's database, we estimate that only 6 sources can currently comply with the proposed standards. We believe such a result is well beyond what is required or intended for the MACT program.

C. The Proposed Rule Fails to Adequately Account for Variability in Emissions That Reasonably is Expected From the Top Performing Sources

EPA has improperly developed a CO standard that boilers must meet at all times based on 3-run stack tests that fail to properly characterize the highly variable nature of CO emissions in solid-fueled boilers. CO emissions from boilers can be highly variable, especially when fuel mix and load change. Facilities are typically required to conduct stack tests at least 90 percent of full load during normal operating conditions. Therefore, a CO stack test is going to represent the best operation of any boiler. EPA has used only 3-run stack test data, which represents only a small and unrepresentative snapshot in time captured during the best operating conditions, to set emission limits for a pollutant that is highly variable.

In fact, as demonstrated in the comments below, further analysis of CO CEMS data included in EPA's database for top performing units in each of the solid fuel subcategories reveals that even the top performing sources would not be able to meet the proposed CO standards that are based on the performance of those very units. Further analysis of record data also clearly shows that EPA is mistaken in its suggestion that CO emissions do not vary with load. In fact, to adequately accommodate expected CO emissions variability with load, the 2004 Industrial Boiler MACT rule did not require CO CEMS data obtained at less than 50 percent of maximum load to be included in the 30-day CO average. EPA's proposal not to accommodate load variability is not supported by the record and inexplicable as a technical matter.

EPA makes a similar mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages … [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards."[42] On the other hand, EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

More generally, EPA proposes to use the 99 percent upper predictive limit ("UPL") to accommodate and reflect variability in the operation of the best performers in calculating the MACT floor. The use of the 99 percent UPL calculated on only a small number of sources in a subcategory does not adequately capture variability or serve to predict the MACT floor level achievable by the top performers. In essence, the Agency is using this statistical method in an attempt to overcome the limited amount of emissions data available for top performers. However, this statistical approach cannot overcome the fact that the data are not representative of the entire population of boilers in each subcategory and that the available data do not reflect the true variability of the top performing sources.

In the final rule, EPA must use data to set the standard that are consistent with the form of the standard. As compliance with the CO standard is to be measured at all times using CO CEMS for units of 100 MMBtu/hr and greater and the averaging time is 30 days, EPA should use 30-day CEMS data from affected boilers to establish the appropriate MACT floors and not 3-run stack test data. To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction.

Lastly, we identify two statistical errors needing correction. First, instead of using the UPL, EPA should use the upper tolerance limit ("UTL"), which is meant for use in

[42] 75 FR 32013

situations where the available data does not represent the entire population. In addition, since the proposed 99% confidence interval is applied to all 5 HAPs, the combined probability of achieving the set of limits drops to 95%, which is inappropriately low when facilities must be in compliance 100% of the time. EPA therefore should use a 99.9% confidence limit for all standards.

D. EPA Should Establish Health-based Emissions Limitations Under § 112(d)(4) Whenever Appropriate

Section 112(d)(4) authorizes EPA to set health-based emissions limitations when establishing standards for HAPs under § 112(d). Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done.

The default technology-based method of setting MACT standards is a cookie cutter approach that can and does result in HAP emissions limitations that are Draconian relative to what is needed to protect the public from HAP emissions. The clear purpose of § 112(d)(4) is to prevent this from happening. The legislative history of § 112(d)(4) is abundantly clear on this point. In formulating § 112(d)(4), Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment."[43] As a result, § 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established … and the pollutant presents no risk of other adverse health effects, including cancer…."[44]

When the first Industrial Boiler MACT was promulgated in 2004, it included health-based emissions limitations for two HAPs – hydrogen chloride ("HCl") and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time, these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected. It was estimated at the time that these health-based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied.

In the newly proposed Industrial Boiler MACT, EPA acknowledges its authority under § 112(d)(4) to establish a health-based emissions limitation for threshold pollutants in lieu of a MACT emissions limitation. However, the Agency proposes not to establish any health-based emissions limitations "[g]iven the limitations of the currently available information (*i.e.*, the HAP mix where boilers are located, and the cumulative health impacts from co-located sources), the environmental effects of

[43] S. Rep. No. 101-228 (1990) at 171.
[44] *Id.*

HCl, and the significant co-benefits of setting a conventional MACT standard for HCl."[45] Nevertheless, EPA asks for comment on a wide range of issues related to the justification for setting health-based emissions limitations and the method by which they should be set.

Ample scientific information supports a determination that HCl, hydrogen fluoride, hydrogen cyanide, and manganese are threshold pollutants and, thus, are eligible to be regulated under § 112(d)(4). In addition, the Agency has the technical tools and significant factual support for establishing health-based emissions limitations for these HAPs that would provide the requisite ample margin of safety to health and the environment. Thus, health-based emissions limitations are fully justified on scientific and technical grounds. EPA should set health-based emission limitations for HAP acid gases and, as in the 2004 rule, a health-based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health-based compliance alternative for manganese).

From a legal standpoint, the statute makes clear that criteria pollutant co-benefits associated with the proposed MACT standards may not be considered in deciding whether to establish § 112(d)(4) health-based emissions limitations. Also, EPA has failed to explain why the health-based emissions limitations it established in the 2004 Industrial Boiler MACT and the justification provided for those limitations should now be reversed. The preamble to the newly proposed rule sets out a number of questions that might be relevant in deciding whether to establish health-based emissions limitations, but merely asking questions is not a sufficient basis for reversing prior determinations adopted through notice and comment rulemaking. Thus, EPA's proposal not to set health-based emissions limitations runs counter to the law and is based on an inadequate explanation of why the Agency proposes to depart from its prior approach.

E. The Emissions Database Includes Numerous Fundamental Flaws That Compromise the MACT Floor Analysis That is Based on These Data

Given the limited comment period that has been provided on the Industrial Boiler MACT proposal, it simply has not been possible to conduct a thorough data quality assessment on EPA's entire emissions data base. EPA's failure to provide adequate time for an appropriate assessment of the data violates the Agency's obligation to provide a full and fair opportunity for public comment on the proposed rule. Within these severe time constraints, we conducted a spot check of approximately 100 stack test reports and associated information from top performers in order to assess the quality of the data the Agency relied upon in calculating the MACT floors that underlie the proposed rule.

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[45] 75 FR 32032.

This spot check revealed numerous data errors – many of which, if corrected, would have a material impact on the stringency of EPA's calculated MACT floors and associated proposed standards. To name just a few, there was: (1) widespread inconsistency in the data reported under the Phase I and Phase II ICRs, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results; (3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fueled boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Along the same lines, the fact that EPA has not finalized the waste definition rule[46] prior to asking for public comment on the Industrial Boiler MACT creates a fundamental procedural problem that is not solved by EPA's alternative MACT proposal.[47] While the waste definition proposal does set forth two basic approaches to distinguishing waste from fuel, the proposal also asks for comments on numerous specific elements of each of these approaches.[48] As a result, the proposal sets out a continuum of possible final rules rather than two distinctly different possibilities. This means that commenters on the proposed Industrial Boiler MACT have no way of knowing what population of units will qualify as boilers upon promulgation of the waste rule and, therefore, cannot conduct a meaningful review of the Industrial Boiler MACT emissions database with regard to the units that ultimately will be used to determine the MACT floors and MACT standards.

The inability to reasonably ascertain which units will actually be used in setting the final Industrial Boiler MACT standards prevents commenters from developing meaningful comments on the emissions database and on EPA's manipulation of the data that ultimately will be used to set the standard. In short, EPA's proposed rule effectively requires commenters to guess what data EPA will eventually use to set the standard. This violates EPA's duty to provide a full and fair opportunity to develop and submit comments on the proposal. This problem can only be cured by

[46] The waste definition rule is proposed at 75 Fed. Reg. 31844 (June 4, 2010).
[47] *See*, 75 FR 32035 ("Alternative Standard for Consideration").
[48] *See*, *e.g.*, *id*. at 31873 ("EPA is proposing that non-hazardous secondary materials used as fuels in combustion units that remain within the control of the generator and that meet legitimacy criteria specified in section VII.D.6 would not be solid waste ….Nevertheless, EPA is seeking comment on whether such secondary materials should be considered solid wastes and thus, be subject to the CAA section 129 requirements if combusted.")

promulgating the waste rule and then proposing industrial boiler standards based on the units that are then known to be industrial boilers.

V. Conclusion

NMA respectfully urges that EPA defer final action on the two rules at issue here until the Agency has produced a cumulative impact assessment. In addition, these comments demonstrate both the need and ability for EPA to revise these industrial boiler proposals to address fundamental technical, legal and data-related issues that subject the proposals to challenge. Owners and operators of industrial boilers and process heaters would be required to invest time and resources into extensive retrofits in order to meet tight compliance deadlines. At a time when the U.S. economy requires every opportunity to recover from the most drastic economic downturn since the Great Depression, the nation's industrial backbone is faced with further impediments. NMA appreciates the opportunity to submit these comments.

Sincerely,

Ben Brandes
Director, Air Quality
National Mining Association

BRUCE WATZMAN
Senior Vice President, Regulatory Affairs

October 1, 2010

VIA ELECTRONIC MAIL TO: a-and-r-docket@epa.gov

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Nos. EPA-HQ-OAR-2009-0491

Re: *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 75 Fed. Reg. 45,210 (Aug. 2, 2010)

Dear Ladies and Gentlemen:

I. Introduction

The National Mining Association (NMA) submits these comments on the proposed Transport Rule. NMA is a national trade association of mining and mineral processing companies whose membership includes the producers of most of the nation's coal, metals, industrial and agricultural minerals; the manufacturers of mining and mineral processing machinery, equipment and supplies; and the engineering and consulting firms, financial institutions and other firms serving the mining industry. NMA's members mine over 75 percent of the coal produced annually from operations located in 26 states.

NMA's comments are divided into two sections. We first discuss EPA's failure to provide a cumulative impact assessment of the proposed rule in light of all of the various rulemaking activity that the Agency has undertaken that will affect the use of coal in this country and, in turn, the cost and reliability of the nation's electricity supply. We urge the Agency to conduct such an analysis and provide a suggested format. We then comment on the timing of the emission reduction targets set forth in the proposed rule.

II. EPA Must Produce a Cumulative Impact Analysis of Its Regulatory Program Affecting the Use of Coal

A. Overview

As discussed in more detail below, NMA believes that the regulatory analysis supporting the proposed Transport Rule is fatally flawed because it fails to take into account the cumulative impact of all of EPA's now-numerous completed, pending and expected rulemakings that are intended to and will have the effect of substantially reducing the usage of coal in the United States.[1] These rulemakings include those affecting the use of coal for electric generation, where EPA is implementing a coordinated program to create, in its words, a "clean, efficient, and completely modern power sector," those affecting the use of coal for industrial, commercial and institutional purposes, such as the two rules specifically at issue here, and those directly affecting coal mining.

All of these rulemakings together will produce a dramatic and cascading series of effects not only in the coal industry but throughout the economy. There will be direct effects on coal employment and indirect effects on employment generally in the economy as a result of higher energy prices. Higher energy prices will also affect GDP and economic activity generally. American competitiveness will also be affected, as higher prices undermine the ability of American business to compete, with resulting offshoring of American business and jobs.

Impact analysis performed by EPA now proceeds on a rulemaking-by-rulemaking basis, as if one rulemaking is unconnected to the next and as if the regulatory consequences are not cumulative. As a result, EPA's impact analyses mask the cumulative effect of the Agency's overall regulatory program. Individual-regulation impact analyses often predict limited effects, when in truth the overall program may produce extremely large consequences.

This balkanized approach to impact analysis impairs the public's right to notice and comment regarding EPA regulation. For instance, EPA's Regulatory Impact Analysis for the proposed Transport Rule shows relatively minor effects, which might lead the public to believe that the rule is relatively innocuous. Cumulative analysis, on the other hand, could lead to a far different conclusion—that coal usage will decline dramatically as a result of the combined effect of numerous EPA rulemakings with attendant serious economic consequences. Armed with that information, the public would likely provide significantly different comment on the rule.

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[1] The draft RIA is fundamentally flawed for another reason as well. On September 1, 2010, EPA published a Notice of Data Availability (NODA) indicating that EPA had changed the assumptions it used in its modeling in support of the proposed rule, with one of the principal changes being changed natural gas supply and price assumptions. EPA, however, did not publish a new draft RIA that reflects the new modeling assumptions. At this point, therefore, the public does not know exactly what the regulatory impacts of the rule will be. NMA will address this point in more detail in its comments on the NODA.

Cumulative impact analysis is not just good policy, it is required by law, both by Executive Order 12866 and the notice and comment rulemaking provisions of the Clean Air Act ("CAA"). NMA therefore urges EPA to defer final action on the two rules at issue here until the necessary cumulative impact assessment is produced. The specific type of analysis that NMA recommends is set forth as an attachment to these comments.

B. Cumulative Analysis Is Needed

1. EPA's coordinated regulatory agenda to reduce coal usage

EPA has undertaken a far-reaching regulatory program that is apparently designed to reduce the use of coal throughout the American economy. The coordinated nature of this program is most evident in the electric power sector, which EPA has undertaken to transform. Upon taking office, EPA formulated seven priorities, one of which was to "develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable reduction goals for SO_2, NO_2, mercury and other air toxics."[2] This goal was reiterated by EPA in the proposed Transport Rule, where the Agency said that "[i]n furtherance of this priority goal, and to respond to statutory and judicial mandates, EPA is undertaking a series of regulatory actions over the course of the next 2 years that will affect the power sector in particular."[3]

These EPA rulemakings include:

- The recently completed National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("SO_2") and nitrogen dioxide ("NO_2");

- The currently proposed new ozone NAAQS and the soon-to-be-proposed new $PM_{2.5}$ NAAQS;

- The proposed Transport Rule and expected additional transport rules for the 1997 ozone NAAQS, the currently proposed new ozone NAAQS, and the soon-to-be-proposed new $PM_{2.5}$ NAAQS;

- The soon-to-be-proposed MACT standards for electric generating units ("EGUs");

- EPA's greenhouse gas ("GHG") regulation under the Prevention of Significant Deterioration ("PSD") program;

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[2] *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator's January 12, 2010 outline of the Agency's seven priorities.

[3] *Id.*

- The soon-to-be-proposed New Source Performance Standards for EGUs (including GHG NSPS);

- Best Available Retrofit Technology ("BART") standards for EGUs;

- The proposed regulations for coal combustion residues; and

- The soon-to-be-proposed water quality regulations for cooling intake structures and soon-to-be-proposed effluent guidelines for discharges from power plants.

Recognizing that all of these regulations are implementing a single overall priority goal and constitute a "comprehensive set of requirements,"[4] EPA pledged in the proposed Transport Rule to coordinate at least its power sector air quality regulations and, to the extent it could under relevant statutory law, to coordinate these power sector air quality regulations with the coal combustion residue regulations and the two power sector water quality regulations.[5] EPA further pledged to "engage with other federal, state and local authorities, as well as with stakeholders and the public at large, with the goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds, resulting, in turn, in the creation of a clean, efficient, and completely modern power sector."[6]

EPA's regulatory agenda for the power sector will almost certainly significantly reduce the use of coal for electric generation. While EPA so far has not done any study of the cumulative impact of these regulations on coal use (or otherwise), the contractor EPA uses to model impacts of individual regulations recently produced its own analysis showing that just the EGU MACT standards alone will force major retirements of coal-fueled powerplants.

A recent report by Credit Suisse (copy attached) examined the effect of the Transport Rule and the upcoming EGU MACT rules and determined that:

- About 60 GW of coal-fueled capacity will likely close between 2013 and 2017.

- $70-$100 billion of capital expense in emission control equipment.

- A 15-31% reduction in the use of coal for electric generation.

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[4] *Id.*

[5] *Id.*

[6] *Id.*

- MISO, SERC, PJM-West, and SPP will see an "accelerating reversion to 15% reserve margins."

- EPA's standards cannot be met unless compliance deadlines are extended to 2017.

Forced retirements will have substantial negative economic impacts nationally, but will also have severe impacts locally, as exemplified by the Arizona Hopi and the Navajo Generation Station:

> Scott Canty, the Hopi Nation's general counsel, explained to a panel of lawmakers on Nov. 2 that closure of the Navajo Generating Station would cripple the tribal government. The Hopi Nation relies heavily on coal revenues to fund its government, Canty said. About 88 percent of the tribal government's budget comes from revenue generated by coal-fired energy production at the Navajo Generating Station, Canty said. . . . The EPA has proposed rules that would require the power plant to install expensive emissions equipment to address visibility impairment issues at the Grand Canyon. But the plant's owners and the tribes argue that the retrofit is too costly.[7]

Moreover, news accounts recently reported that EPA is well aware that its regulatory efforts in the power sector will increase the costs to coal-fueled EGUs and make them less competitive with renewable resources. In an article entitled "Administration Eyes EPA Rules To Spur Shift From Coal To Renewables," it was reported that:

> Rob Brenner of EPA's Office of Air & Radiation told a July 28 meeting of the agency's environmental justice advisers that pending rules to control emissions, waste and water discharges from utilities will not only protect public health but add costs to the industry that might make renewable energy a more viable alternative.
>
> "We need to set health-based standards for power plants, and once we do that then they can compete with some of these renewable sources," Brenner said at the National Environmental Justice Advisory Committee (NEJAC) meeting in Washington, DC. He added later, "It's not

[7] Luige del Puerto, *Hopi Nation in Arizona appeals for help as coal plant face disclosure,* ARIZ. CAP. TIMES, Nov. 3, 2009, *available at* http://www.allbusiness.com/government/government-bodies-offices-regional/13389633-1.html.

> really a fair competition because [coal-fired power plants] are cheaper than they should be because they're not controlling their pollutants" to their full extent because EPA is yet to issue key rules for the sector, including a mercury air rule and a plan to regulate coal combustion residue.[8]

The same article reported that the White House also understands that transforming the power sector will inevitably result in reduced use of coal and increased use of renewables. Referring to remarks of Nancy Sutley, Chair of the White House Council on Environmental Quality, the article reported that:

> Sutley responded that she doubts the existence of so-called clean coal. "Other people have labeled it 'clean coal,'" she said. "I don't know if I would necessarily concede that that is real. . . . I think in the long run, not just for the [United States] but for the world, that developing and making sure that there is access to these inherently cleaner sources of energy is important. . . . . We need to use energy more efficiently and more cleanly."[9]

Other EPA regulatory proposals are also part of an overall strategy to reduce the use of coal throughout the economy. This strategy includes the Boiler MACT and Area Source rule on which EPA recently took comment. In the regulatory preamble to the Boiler MACT rule proposal, EPA stated forthrightly that its reason for proposing strict MACT standards for coal boilers and process heaters but only work practice standards for natural gas boilers was to incent coal boilers to switch to natural gas and to disincent natural gas boilers from switching to coal.[10] In discussing this issue, EPA made plain that it considers coal to be a "dirty" fuel whose use is inconsistent with the CAA and therefore should be discouraged.[11] In contrast, EPA considers natural gas to be a "clean fuel" whose use should be encouraged at coal's expense. According to EPA:

> In addition, emission limits on gas-fueled boilers and process heaters may have the negative effect of providing

[8] *Administration Eyes EPA Rules to Spur Shift from Coal to Renewables*, InsideEPA.com (July 29, 2010), *at* http://insideepa.com/201007291915893/EPA-Daily-News/Daily-News/administration-eyes-epa-rules-to-spur-shift-from-coal-to-renewables/menu-id-95.html.

[9] *Id.*

[10] *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, 75 Fed. Reg. 32,006, 32,025/3 (June 4, 2010).

[11] *Id*.

> an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (i.e., coal).[12]

The coal industry also faces a panoply of prospective regulation of the process of producing coal. These regulations include potentially stricter NAAQS for PM_{10} which may make western surface mining untenable, new restrictions on coal mine permitting in Appalachia that could result in major reductions in surface and underground coal mining in that region, and potential imposition of NSPS standards on mining emissions of PM_{10}, methane, volatile organic compounds, and nitrogen oxides. All of these regulations together—EPA's power sector regulations, its regulations for the use of coal in the manufacturing and commercial sectors, and its regulations of coal mining—all have the potential to combine to cumulatively and dramatically reduce coal usage.

2. The effect of each EPA individual rule affecting coal, including the rules at issue here, cannot be understood without a cumulative analysis

Given EPA's intent to transform the power sector from what it is today into something different and given its efforts to reduce coal use throughout the economy, EPA must produce a cumulative and economy-wide assessment of this program. As EPA has proposed and finalized each individual regulation, including the proposed Transport Rule, EPA's impact analysis has been limited to the effect of the specific regulation in question. However, to understand the effect that all the rules together will create, it is necessary to study the effect of that program in toto.

These effects could be extremely large. For instance, EPA projects the annual cost of the SO_2 NAAQS to be $2.9 billion to $3.0 billion in 2020, with most of those costs associated with the power sector[13]; the annual cost of the Transport Rule (all in the EGU sector) to be $3.7 billion in 2012 and $2.8 billion in 2014,[14] with another $2 billion in 2020 and 2025[15]; the annual cost of the ozone standard to be $32 – 44 billion, again with much of that cost in the EGU sector[16]; and the total costs of the coal combustion residue rule to be over $8 billion under the Subtitle D option and

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[12] *Id.*

[13] U.S. Environmental Protection Agency, *Final Regulatory Impact Analysis (RIA) for the SO2 National Ambient Air Quality Standards (NAAQS)* at 7-4, Table 7.1, June 2010 (Docket ID EPA-HQ-OAR-2009-0769-0059).

[14] 75 Fed. Reg. at 45348/1.

[15] *Id*. at 45333, TableV.E-1.

[16] U.S. Environmental Protection Agency, *Final Ozone National Ambient Air Quality Standards (NAAQS) Regulatory Impact Analysis* at 5-23, March 2008 (Docket ID EPA-HQ-OAR-2005-0161-2849) (estimate for 0.065 ppm standard; EPA's proposal is 0.060-0.070).

over $20 billion with the Subtitle C option.[17] Despite the request from NMA and others for EPA to assess the cost of its GHG regulatory program, EPA has refused to do so, and so that cost is unknown but could be very substantial as well. The other programs identified above will also add significant cost, with the new EGU MACT standards expected to have a potentially a very large impact.

But these estimates, as large as they are, mask the overall effect of the regulations when considered cumulatively. The proposed Transport Rule is an example. EPA's draft Regulatory Impact Analysis ("RIA") for this proposed rule envisions relatively small impacts to coal usage. EPA projects that EGUs can meet the requirements of the rule by switching from high sulfur to low sulfur coal and by installing pollution control equipment, with the result that EPA estimates the retirement of only 1.2 GW of "small and infrequently used" coal-fired generating units by 2014.[18] Based on the foregoing, EPA projects additional cost to the utility industry of $3.7 billion in 2012 and $2.8 billion in 2014 ($2006).[19]

This EPA projection of almost no impact to the coal industry, however, is not meaningful because it is based on an analysis of the Transport Rule in isolation. Thus, even if EPA's projected assessment of the effect of the Transport Rule on coal is correct, that assessment assumes that there are no other forthcoming EPA regulations that will affect the use of coal, an

[17] *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities*, 75 Fed. Reg. 35218, 35134, Table 1 (June 21, 2010).

[18] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Proposed Federal Transport Rule* at 14, June 2010 (Docket ID EPA-HQ-OAR-2009-0491-0078).

[19] *Id*. at 31.

> assumption that is clearly wrong. The control options that the Transport Rule RIA envisions appear to exhaust (and likely go beyond exhausting) the ability of the power sector to absorb EPA regulation without large-scale closings of coal plants. The next regulation following the Transport Rule that adds cost to coal-fueled electric generation therefore will force plant closings, but it is incorrect to say that it was that next regulation and not the Transport Rule that causes the plant closings. Both rules and indeed the entire program cause that effect.

EPA itself recognizes the need for cumulative analysis in an analogous situation. EPA requires that EPA reviewers of Environmental Impact Statements ("EISs") under the National Environmental Protection Act ("NEPA") take cumulative impacts into account, including consideration of "impacts that are due to past, present, and reasonably foreseeable actions."[20] According to EPA, in assessing environmental impacts, it is necessary to assess "[t]he combined, incremental effects of human activity" rather than just the impacts of the particular action for which federal approval is sought.[21] This is based on the recognition that individual actions "may be insignificant by themselves," but that cumulative impacts accumulate over time, from one or more sources and these cumulative effects must be taken into consideration.[22]

The Council on Environmental Quality ("CEQ") also requires cumulative impact analysis in EISs. CEQ regulations require that agencies considering major actions that could affect environmental quality consider the "overall, cumulative impact of the action proposed (and of further actions contemplated)."[23]

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[20] U.S. Environmental Protection Agency, *Consideration of Cumulative Impacts in EPA Review of NEPA Documents* (May 1999) at 10.

[21] *Id*. at 1.

[22] *Id*.

[23] 35 Fed. Reg. 7390, 7391 (1970). It should be emphasized that CEQ does not distinguish between cumulative analysis of environmental impacts and of socioeconomic impacts. Under CEQ regulations, agencies must examine the effect of the proposed action on the "human environment." 40 C.F.R. § 1508.14 states that "[h]uman environment" shall be interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment." While "economic or social effects are not intended by themselves to require preparation of an environmental

EPA's and CEQ's reasons for requiring cumulative impact analysis in EISs apply with equal force to economic analysis that EPA performs of its regulations. Where effects of a proposed action accumulate with those of other related actions, examining the effects of the proposed action in isolation will mask the overall effect of the action. That is as true for EPA's regulatory efforts to reduce coal usage as it is for environmental analysis in the NEPA context. To again cite the proposed Transport Rule as an example, as stated, EPA concludes that the rule will not materially affect the use of coal for electric generation.[24] But under the rationale of CEQ's NEPA regulations, cumulative impact analysis should be conducted because "[c]umulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[25]

C. Cumulative Analysis is Legally Required

Cumulative analysis does not just make good regulatory sense; it is legally required. Two separate authorities require cumulative analysis here.

1. Executive Order 12866

Executive Order 12866 specifically requires cumulative analysis as follows:

> Each agency shall tailor its regulations to impose the least burden on society, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable*, the costs of cumulative regulations.*[26]

This requirement for cumulative analysis stems from the regulatory philosophy of Executive Order 12866 that the need for and effects of government regulatory actions should not be examined in isolation but instead on an overall and coordinated basis. The preamble to the Order found that the then current regulatory system did not work in a way that produced efficient results or regulations that were "effective, consistent, sensible, and understandable."[27] The

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impact statement," "[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." This applies to cumulative analysis: where socioeconomic effects accumulate from multiple actions, they must be assessed cumulatively, just as environmental effects must be assessed cumulatively. Thus, cumulative analysis is as relevant for examining socioeconomics as it is for analyzing environmental impacts.

[24] 75 Fed. Reg. at 45357/1.

[25] 40 C.F.R. § 1508.7.
[26] Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993) (emphasis added).

[27] *Id*.

first objective of the Order, therefore, was to "enhance planning and coordination with respect to both new and existing regulations."[28] In that vein, the main administrative provisions of the Order—an interagency Planning Mechanism, the requirement that each agency produce a Unified Regulatory Agenda and develop a Regulatory Plan, the requirement for a Regulatory Working Group and the provision for quarterly Conferences among OIRA and state, local and tribal governments—were all included to enhance coordination of any specific regulation proposed by an agency with that agency's other existing and contemplated regulations, with other regulations of other agencies, and with the President's overall regulatory priorities.[29]

The Statement of Regulatory Philosophy and Principles in Executive Order 12866 also stressed the need for coordination. This Statement provides that "[i]n deciding whether and how to regulate, agencies should assess *all* costs and benefits of available regulatory alternatives."[30] Agencies are instructed to "examine whether existing regulations (or other law) have created, or contributed to, the problem that a new regulation is intended to correct and whether those regulations (or other law) should be modified to achieve the intended goal of regulation more effectively"[31]; to "base its decisions on its best reasonably obtainable scientific, technical, economic, and other information concerning the need for, and consequences of, the intended regulation"[32]; and to "avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations or those of other Federal agencies."[33] Indeed, the preamble to the Executive Order states that "[t]he objectives of this Executive order are to enhance planning and coordination with respect to both new and existing regulation…."[34]

This requirement for coordinated government action based on coordinated and cumulative analysis built on the same requirement in Executive Order 12291, the predecessor order to Executive Order 12866 and the Order which first required agencies to prepare Regulatory Impact Analyses. Executive Order 12291 required agencies, in promulgating new regulations, to "tak[e] into account the condition of

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[28] *Id*.

[29] *Id*.

[30] *Id*. (emphasis added)

[31] *Id*. at 51735-36.

[32] *Id*. at 51736.

[33] *Id*.

[34] *Id*. at 51735.

the particular industries affected by regulations . . . *and other regulatory actions contemplated for the future*."[35]

The Executive Order 12866 requirements for coordinated and cumulative analysis apply with particular force to EPA's efforts to remake the power sector and its apparent effort to reduce coal usage throughout the economy. As shown above, each individual regulation that EPA promulgates in this area, including the Transport at issue here, is part of a single overall program with cumulative consequences.

Moreover, EPA cannot say that cumulative analysis is not "practicable" within the meaning of section 1(b)(11) of Executive Order 12866. EPA obviously has very sophisticated modeling techniques at its disposal. If in any one rulemaking EPA believes that it cannot anticipate and therefore assess the effects of future rulemakings, EPA can assess a range of possible future regulation. Certainly, the fact that EPA has indicated that it has an overall program in furtherance of one of the Agency's seven priorities suggests that EPA has a fairly concrete idea of the range of regulatory outcomes that it anticipates. Alternatively, EPA can delay any particular rulemaking until it has better information about future regulatory requirements that it intends to impose. What EPA cannot do, however, is to follow its current regulatory course, where the Agency analyzes individual rulemaking effects in isolation, as if there is no overall regulatory context.

2. CAA

Cumulative impact analysis is also legally required under the rulemaking provisions of the CAA where, as here, EPA has undertaken coordinated and comprehensive regulation of the power and coal sectors through a series of related rulemakings. The purpose of these CAA rulemaking provisions is both to ensure good regulatory outcomes and to protect the public's right to have adequate notice of the need for and effect of EPA regulatory action so that the public can provide meaningful comment.

In this context, section 307(d)(3) of the CAA requires that a rule be accompanied by a statement of its basis and purpose, including "the major legal interpretations and *policy considerations* underlying the proposed rule."[36] For the reasons discussed above, an underlying policy consideration of the Transport rule at issue here is EPA's overall intent to incent reductions in coal usage and increases in resources that EPA considers to be "clean." That being the case, EPA must provide an analysis of the consequences of this policy so that the public can comment adequately. As stated, the coal industry and public at large might have an entirely

[35] Exec. Order No. 12,291 at § 2(e) (emphasis added).

[36] 42 U.S.C. § 7607(d)(3) (emphasis added).

different view of these proposed rules if EPA produced a cumulative assessment rather than the narrow assessment reflected in the RIA.

> The U.S. Court of Appeals for the D.C. Circuit has stated that "[i]t is not consonant with the purpose of a rulemaking proceeding to promulgate rules on the basis of inadequate data, or on data that, [in] critical degree, is known only to the agency."[37] Unless the public knows the overall consequences of EPA's regulations in context of other related regulations, the public's right to provide adequate comment is compromised.

Additional support for cumulative analysis is found in section 318 of the CAA, which requires that the Administrator undertake an analysis of the cost of complying with various EPA actions, including rulemakings under section 111(d). Under section 318(d), such analyses "shall be as extensive as practicable" consistent with the standards set forth in that provision.[38]

D. Scope and Content of a Cumulative Impact Assessment

NMA believes that the cumulative impact assessment should examine the following factors.

- Overall impacts on the economy. Specifically, the effect on GDP and jobs. In this regard, some of EPA's regulations (in particular, the NAAQS) will not just affect energy but will affect other sectors of the economy as well both directly (for example, through direct regulation of manufacturing sources) and indirectly (for example, through increased energy costs). EPA should examine all reasonably foreseeable effects of its regulations on the overall economy.

- Energy. This part of the analysis should include impacts on energy production and usage, energy costs, including fuel costs and retail electricity prices, and energy employment should be determined. Changes in the energy mix in the United States should be shown over time, including electric capacity additions and reductions by fuel type. Employment and energy cost impacts should be estimated for each energy sector.

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[37] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 373, 393 (D.C. Cir. 1973), *cert. denied* 417 U.S. 921 (1974).

[38] 42 U.S.C. § 7617(d).

- Competitiveness. This part of the analysis should include impacts on industrial and manufacturing production and competitiveness. EPA should determine the impacts of regulation on cost of production and employment in the relevant sectors, and the extent to which production and jobs will be reduced as a result of higher costs and foreign competition.

- Study design. Scenarios should be constructed for a business-as-usual case (without adoption of the contemplated regulations) and a case where EPA adopts the contemplated regulations. Additional scenarios may be included to test the findings under different appropriate assumptions. Where EPA regulation does not directly regulate but instead requires states to adopt regulations meeting EPA standards (for instance, EPA regulation under the NAAQS program and NSR/PSD program), EPA should estimate state regulatory responses, using a range if necessary. All assumptions, analytical methods and underlying data (or appropriate citations to data sources) should be provided. All impacts should be broken down on a state-by-state basis. Regulations included in the study should not be limited to just those listed in NMA's comments but should include any other EPA regulations that EPA believes will affect the nation's economy, production and usage of energy and manufacturing.

III. Other Comments

A. EPA Has not Provided an Adequate Opportunity for Comments

Apart from the cumulative impact assessment issue, EPA has made it very difficult, indeed impossible, to provide meaningful comments on the proposed rule. In the first place, EPA's intention to begin phase one of the proposed rule in 2012 resulted in an insufficient time for comments, only sixty days despite the extraordinarily complex nature of the proposed rule and the underlying analysis that supports the rule. NMA counts more than 20 Technical Support Documents as well as numerous modeling files in the record. In particular, the modeling and the assumptions underlying the modeling drive all facets of the rule, including the air quality analysis and the determination of individual state significant contributions to downwind non-attainment or interference with maintenance, and this in turns drives calculation of state budgets and whether states are classified as group 1 or group 2 states. Sixty days is not enough time to analyze and understand this material.

The Agency should not provide an inadequate amount of time to comment because of a self-imposed and impractical deadline to begin regulation. But the 2012 deadline is not feasible—and its extension would provide the collateral benefit of allowing the public more time to understand this complex rulemaking and to provide useful comment to the Agency.

The insufficient time to comment is compounded by EPA's September 1, 2010 Notice of Data Availability (NODA), which indicates that EPA has made fundamental changes to the assumptions used in the modeling to support the rule. These changes evidently are sufficient to change EPA's air quality analysis and cost-effectiveness analysis and therefore the emission budgets and even potentially whether states are classified in group one or two. Indeed, even at this point EPA has not fully explained how its proposal has been changed by the new modeling assumptions, as EPA says that the state budgets "have not been modified to account for any changes that the modeling might suggest."[39]

In essence, the comments that EPA has called for as of October 1, 2010 pertain to an obsolete proposal, one that is different from the one that EPA is now considering and one that still has not been fully explained. But since the public has not yet had an opportunity to examine and fully understand the NODA, the public cannot be sure in exactly what ways the original proposal on which it is now commenting may or may not remain valid.

In these circumstances, it would have been far better for EPA to have delayed the entire comment period so that the public had at least an additional sixty days to comment on the entire rule after publication of the NODA. But with phase one of the rule nearing, EPA evidently concluded that there was insufficient time to do so. This problem could have been solved had EPA proposed the Transport Rule sooner and, when it did so, the Agency had completed its underlying analysis, and therefore the proposal itself. The problem can still be solved if EPA will delay the phase one requirements, a course it should do anyway given the lack of feasibility of the phase one requirements.

B. 2012 Is Too Soon to Begin Phase One Regulation, and 2014 Is Too Soon to Begin Phase Two Regulation

1. 2012

EPA proposes to require compliance with phase one requirements under the proposed rule at the beginning of 2012, just six or so months after EPA anticipates completion of the rule.[40] This is wholly unrealistic. States will not have had an opportunity to examine and understand the final rule and adopt State Implementation Plans (SIPs), and sources will not have had an adequate opportunity to plan for the new requirements.

The phase one emission reduction obligations are significant. EPA indicates that the 2012 SO2 emission reductions required under the rule will be 4.1 million tons per year, as compared with 5.1 million tons that would be expected otherwise.[41] EPA evidently believes that this significant amount of emission reductions is feasible by the beginning of 2012 because, in EPA's analysis, sources will not be required to

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[39] *See* 75 Fed. Reg. at 53614/3.
[40] EPA states that it anticipates issuance of the final rule in "June." *See* slide 22 of "Overview Presentation 7/26/2010," http://www.epa.gov/airquality/transport/actions.html.

[41] *Id.,* slide 33. In a presentation by EPA held after the rule was proposed, EPA said that the 2012 cap under the rule would be 3.9 million tons, a difference that, so far as NMA is aware, has not been resolved.

install new pollution control equipment, beyond those already planned and in development, to meet the requirements of the rule. Instead, EPA believes that the rule's NO_X requirements can be met by operating NO_X control equipment year round, and the rule's SO_2 requirements can be met principally through coal-switching from high sulfur to low sulfur coal and from low sulfur coal to very low sulfur coal.

NMA understands that utility industry commenters will provide significant information showing that EPA has made factual errors in the modeling inputs that were used to demonstrate that the phase one emission reduction reductions could be achieved by the beginning of 2012. For instance, NMA understands that this information will show that EPA has overstated the number of scrubbers that are under construction and will be operational by 2012. If EPA's information is wrong, then the only way the 2012 budgets can be met are by closing units or ramping down production, a result that would fundamentally change the cost-effectiveness of the rule.

Moreover, NMA is unable to find any documentation in the record of whether EPA considered whether utilities are constrained by coal supply or rail contracts from switching coal suppliers or coal sources. Many coal and rail contracts extend for a period of years, in many cases for five or ten years or longer. Certainly, as of mid-2011 when the Transport Rule is final, many utilities will be contractually locked into their sources of coal for the 2012-14 period and will therefore be unable to switch coal as EPA anticipates. If they are unable to do so, the 2012 budgets will be unattainable, except by closing coal-fueled units or ramping back production, which in turn will produce different impacts than those that the Agency has analyzed. EPA must at least produce some form of analysis taking into account coal supply and rail contract constraints.

Similarly, NMA is unable to find any documentation in the record of whether EPA considered any physical constraints on substitution of one type of coal for another, except where the switch would entail substitution of very low sulfur subbituminous coal for bituminous coal. But many other types of coal characteristics affect whether coal can be burned in a particular unit even for coal within a single coal region. Unless EPA produces a unit-by-unit analysis demonstrating that coal can be substituted in the manner that EPA anticipates, there will be no certainty that utilities can meet the 2012 compliance deadline through coal-switching and that unit closures or reductions in operations will not be required.

2. 2014

For compliance with the 2014 SO_2 budgets, EPA projects the installation of scrubbers on 14 GW of generation, in addition to the very substantial amount otherwise planned for that period. For NO_X compliance in 2014, EPA projects the addition of SCRs on 51 GW of capacity. EPA expresses confidence that utilities can install scrubbers on 14 GW of capacity during the three year period between 2011 when the Transport Rule goes into effect and 2014 because utilities installed more than that amount of scrubbers in past three-year periods in response to CAIR. But that statement ignores the fact that EPA expects utilities to install scrubbers on an additional 26 GW of capacity by 2014 under what EPA calls other requirements.

This is a great deal of construction activity in a very limited amount of time. In the first place, since EPA has overstated the number of scrubbers that will be brought on line by the beginning of 2012, it has underestimated the number that must be brought on line between 2012 and 2014. Based on comments that will be submitted by utility industry entities, industry estimates show that approximately 25 GW of *new* scrubbers will be required by 2014, not the 14 GW assumed by EPA.

Moreover, NMA understands that utility industry commenters will also be providing information showing that EPA has severely underestimated the time it takes to plan for, design and engineer, and construct scrubbers and SCRs. For example, EPA's estimate that a scrubber can be brought on line in 30 months is based on general industry information taken from a period that did not experience the extremely high volume of scrubber construction that EPA projects in the 2012-14 time period, and the even higher volume of construction that will likely take place in actuality. Furthermore, using general figures masks difficulties that may arise at individual locations. Yet EPA's ambitious schedule requires that every scrubber project be completed by 2014, not just a hypothetical "average" project.

As with EPA's assumptions on coal-switching, if EPA is wrong about the amount of scrubbers that can be installed by 2014, the result will be the closing of coal plants or the ramping down of production at those plants. That result, which EPA has not analyzed, would completely change the basis for EPA's conclusion that its phase two emission reductions are cost-effective.

C. EPA's 2012 and 2014 Deadlines Result in the Usurpation of State Authority under the Clean Air Act

The federalist nature of the Clean Air Act is well-established. EPA sets standards, and states implement those standards through SIPs. Only if states do not submit an adequate SIP may EPA step in and impose a Federal Implementation Plan (FIP).

Under Section 110(c)(1), EPA may impose a FIP within two years after EPA (a) finds that a state has failed to make a required SIP submission or finds that the SIP does not satisfy the minimum criteria under section 110 or (b) disapproves a SIP, unless the State corrects the deficiency. Under Section 110(k)(5), if EPA finds that a SIP fails "to mitigate adequately pollution transport" as may be found by EPA under Sections 176A or 184, "[t]he Administrator shall require the State to revise the plan as necessary to correct such inadequacies." Further, "[t]he Administrator shall notify the State of the inadequacies, and may establish reasonable deadlines … for the submission of such plan revisions."

Thus, where as here, EPA has made findings that states are significantly contributing to the interstate transport of pollution, the required procedure is for EPA to so notify the states and to give them an adequate opportunity to submit a SIP revision. If those SIP submissions are inadequate, EPA may impose a FIP. Here, EPA has improperly reversed the procedure and skipped directly to imposition of a FIP.

EPA's reason for doing so, again, is its rush to begin phase one as of 2012. But EPA's policy interest does not permit it to ignore plain statutory language. Moreover, EPA's statement that imposition of FIPs "would in no way affect the rights of states to submit … a SIP that replaced the federal requirements of the FIP with a state requirement"[42] has it exactly backwards. The opportunity for a SIP precedes the FIP; it doesn't follow it.

EPA seeks to justify immediate imposition of FIPs on the ground that EPA, as a part of CAIR, found that states were significantly contributing to downwind NAAQS non-attainment and therefore already had been given more than the required amount of time to submit conforming SIPs. But, as EPA recognizes, the states fully complied with the requirements that EPA imposed. As EPA states, following EPA's interstate transport findings, EPA in CAIR called for states to cure their SIP deficiencies by submitting SIP revisions that complied with the standards set forth in CAIR. The states did so, and EPA approved their SIPs. The only reason why states could be said to be in violation of CAA interstate transport requirements is because CAIR was overturned in Court. But that was not the state's fault; it was EPA's. Case law supports a "resetting of the deadline clock" where, as here, states cannot meet their statutory obligations because of EPA's failure to carry out its CAA responsibilities. *NRDC v. EPA,* 22 F.3d 1125 (D.C. Cir. 1994).

In short, EPA's imposition of FIPs is improper. EPA should extend the time for compliance with its phase one and two requirements and allow states adequate time to formulate conforming SIPs.

D. The Direct Control Remedy Option Also Usurps State Authority

EPA requests comments on the option of EPA imposing a Direct Control Remedy on individual units by assigning them emission rates. As discussed, however, EPA does not have authority to bypass SIPs and impose specific requirements on individual units. In remedying significant contributions by *states* to downwind attainment under section 110, EPA may impose emission reduction obligations on *states*—but not on individual units.

E. No Need Exists to Enforce More Stringent Requirements than CAIR

[42] 75 Fed. Reg. at 45,342/2.

Despite generating more and more electricity, the electric utility has made steady and continuous progress in reducing emissions. According to EPA data, SO_2 emissions from powerplants declined by 67 percent from 1980 to 2009, and NO_X emissions declined by 72 percent over the same period. Just in the East, NO_X emissions during the ozone season declined by 80 percent.

This progress will continue at the CAIR level of reductions. CAIR was widely supported both by environmental groups and industry. It unraveled principally because of its interstate trading component. But the Court did not require EPA to produce more emission reductions than the CAIR amounts. CAIR was a reasonable program when promulgated, and nothing has happened since it was promulgated to justify further reductions. To the contrary, with the economic situation, load growth and the demand for electricity has flattened. The country has also undertaken a variety of new initiatives to foster renewable resource development.

As discussed above, the feasibility of the 2012 and 2014 emission reductions required by the proposed rule are assumption and model driven—if the assumptions are wrong, the feasibility of the whole program is in doubt and the economic cost the program will rise dramatically. EPA has left the public very little time to challenge (or even understand) these assumptions, and it has left almost no time between finalization of the rule and the 2012 compliance deadline for reconsideration of the rule if the assumptions prove to be faulty. Yet EPA already has in place a program that will lead to an acceleration of the emission reductions that the country has made in the last three decades.

F. EPA Should Use the "Monitored-Plus-Modeled" Approach

Departing from its approach in the NOX SIP Call and CAIR, the proposed rule does not use a combination of monitored and modeled data to determine the downwind nonattainment areas that must be addressed under the rule. Instead, it uses only modeled data. This departure from the approach used in the two previous rules is not explained. The previous approach, however, was preferable because the purpose of the Transport Rule is to remedy real world nonattainment, not hypothetical nonattainment shown by a model. EPA should either return to its previous approach or explain its reasoning for the new approach.

G. The Proposed Rule Does not Assume Sufficient Emission Reductions from Local Controls

The premise behind the proposed rule is that, to cure nonattainment or preserve attainment, upwind sources should control first, then downwind sources should address any remaining problem. As EPA stated, "EPA continues to believe that a strategy based on adopting cost effective controls on sources of transported pollutants as a first step will produce a more reasonable, equitable, and optimal strategy than one beginning with local controls."[43]

In the court decision overturning CAIR, however, the court ruled that EPA's notions of what is "reasonable," "equitable," or "optimal" are irrelevant in applying the CAA.[44] Congress determines what is the "reasonable," "equitable," and "optimal strategy for addressing nonattainment and interference with maintenance; EPA then carries out Congress' wishes. Section 107(a) of the CAA plainly states that "[e]ach State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State." EPA thus has it exactly backwards—under the statute, the nonattaining state must first seek to achieve attainment through local controls, and the upwind states may then be required to address any remaining increment of nonattainment.

EPA's flawed legal analysis is reflected in its base case modeling. That modeling does not assume any further controls on local sources. Had new local controls been assumed, the burden on upwind sources would have been reduced. Moreover, EPA's Emission Inventory TSD states that modeling of the 2014 control case is indeed intended as a complete remedy for nonattainment ("The 2014 TR Control Case was intended to represent the implementation of NO_X and SO_2 reductions to attain the existing ozone and $PM_{2.5}$ NAAQS in the eastern U.S.").[45]

EPA's policy requiring upwind states to go first is based on the Agency's conclusion that upwind controls are lower cost than local controls. Whether or not this is true, it is irrelevant under the CAA. The notion that (presumably) lower cost controls in upwind states should be installed before (presumably) higher cost local controls derives from the Agency's views of interstate equity, a concept that the *North Carolina* court specifically found to be beyond the scope of EPA's power to implement under the CAA. Thus, EPA should at least have modeled a reasonable level of local controls to achieve and maintain attainment, a level that cannot be determined with reference to the cost of upwind controls.

IV. Conclusion

NMA respectfully urges that EPA defer final action on the proposed Transport Rule until the Agency has produced a cumulative impact assessment. Specific recommendations for such an assessment are provided. NMA also urges EPA to change the compliance deadlines in the proposed rule to more reasonable ones and to allow states an opportunity to submit SIPs. NMA appreciates the opportunity to submit these comments.

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[43] 75 Fed. Reg. at 45,226/2.

[44] *North Carolina v. EPA*, 531 F.3d 896, 919 (D.C. Cir. 2008), *modified on petitions for rehearing*, 550 F.3d 1176 (D.C. Cir. 2008).

[45] Technical Support Document (TSD) for the Transport Rule, Docket ID No. EPA-HQ-OAR-2009-0491, Emissions Inventories, June 2010, at 37.

Sincerely,

Bruce Watzman
Senior Vice President – Regulatory Affairs

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March 25, 2011 — Industry Update

Important disclosures can be found at the end of this document

Coal Retirements—25 GW to 50 GW Remain at Risk

Contrary to initial media reports, we believe that EPA's proposed air toxics rule (a.k.a. the Utility MACT) has the potential to lead to a significant number of coal plant retirements. The proposal projects just 10 GW of retirements, but we believe this implies 25 GW of retirements including planned retirements and the forthcoming transport rule. This scenario depends heavily on the widespread adoption of dry sorbent injection (DSI) to control emissions. Our analysis suggests that the potential coal generation retirements from EPA's two rules could be significantly higher if DSI does not prove to be a successful alternative to scrubbing. In a scenario in which DSI is impractical, coal retirements could be north of 50 GW. Thus, we maintain our view that 45 GW in coal retirements is plausible, which would help normalize power markets. Retirements in the 35 GW range are possible if DSI proves more effective than we are assuming. Beneficiaries of the coal fleet transformation are listed below.

- **The EPA's proposed rule is stringent on hazardous air pollutants.** The standards call for reductions of 91% for mercury and acid gases and 55% for sulfur dioxide (SO2). EPA's draft chose to employ few of its flexibility options including subcategorization, health standards, or monitoring during startup, malfunction, or shutdown. To date, the proposed standards for hydrogen chloride (HCl) and mercury (Hg) appear challenging to achieve. Presently, only 12 of the best-performing generation units in each category meet the combination of these two standards. These units are dressed for success and typically sport a full suite of environmental controls (but not DSI). While the EPA has proposed DSI in combination with fabric filters as a means to reduce HCl emissions, our conversations suggest that practical use of this approach may have limits. The proposal would allow for a 30-day rolling average compliance period and unit averaging within a facility.

- **DSI will drive the coal retirement debate.** EPA's headline retirement figure of 10 GW refers to the incremental impact of the MACT rule after accounting for planned retirements and the transport rule. EPA's own gross retirement projection is in fact 25 GW, which reflects widespread adoption of DSI. However, the practical applicability of DSI remains a debatable point due to the disposal of additional ash produced, reliability of the reagent supply chain, the lack of utility sector experience with this technology, and the potential impact on dispatch. More limited adoption of this technology could lift the retirement number above 50 GW. Conversely, widespread adoption of DSI for sub-bituminous coals could reduce our coal retirement expectation from 45 GW to 35 GW. Lower retirement numbers would require even more adoption of DSI for on-the-bubble low-sulfur bituminous coal and from a possible increase in low-sulfur coal blending.

- **Likely beneficiaries of higher retirements include select electric utilities and their suppliers.** For companies under coverage, acceleration in rate base growth is plausible for The Southern Company (SO – Market Perform), Duke Energy Corporation (DUK – Underperform), and Progress Energy (PGN – Market Perform). FirstEnergy Corporation (FE – Market Perform) and PPL Corporation (PPL – Outperform) would likely receive a boost from tightening power markets by 2015. Coal burn affected could reach up to 66 million tons and gas could increase by up to 4.2 Bcf/day.

Table of Contents

The Proposed Rule Is Stringent on Hazardous Air Pollutants

The proposed air toxics rule (a.k.a. the Utility MACT or Maximum Achievable Control Technology rule) may have been initially interpreted by the market as lenient upon its release. This view may have been supported by a number of provisions highlighted by the EPA, such as language encouraging one-year extensions, a carve-out for lignite, unit averaging for emissions, and a 10 GW headline number for coal retirements. However, the feasibility of achieving the HCl standard (a proxy for acid gases) in particular makes this rule a challenge. EPA envisions that this requirement could be met with the widespread use of dry sorbent injection (DSI), a substitute for scrubbers in capturing HCl emissions, and, to a lesser extent, SO2. Practical limitations on the adoption of DSI, including its impact on dispatch, could force more coal retirements than anticipated by the EPA.

By design, the MACT is prospective—the law's goal is to require greater adoption of best-performing technology (see our December 13 note, "Coal Retirements in Perspective—Quantifying the Upcoming EPA Rules," for a legal background). Our examination of what EPA views as the best-performing units in the coal fleet confirms that nearly every coal-fired plant in the country will have to install additional controls in order to comply with the new standards.

- **Very few of the highest-performing plants currently meet the combined requirements for HCl, Hg, and particulate matter (PM).** Utilities must comply with each of the three proposed hazardous air pollutant (HAP) standards (Hg, HCl, and fine particulate matter [PM2.5]) separately. Only 12 of the units used by EPA to represent the top 12% performing units appear to pass both the HCl and Hg standards.
- **Top performing plants are dressed for success, and without DSI.** We analyzed EPA's top-performing units that set the Hg and HCl floors and identified their general profile. Within the Hg group, most bituminous units use an FGD and FF combination, and most sub-bituminous units use an ACI/electrostatic precipitator (ESP) combination. Within the HCl group, most bituminous units (roughly two-thirds of all units that set this floor) use an FGD/FF or FGD/ESP combination. Only five units use solely DSI to control HCl or SO2 emissions.
- **EPA's 10 GW headline coal retirement number from the MACT rule is not the full story. Potential retirements could be higher.** The EPA base case estimates 299 GW of coal generation in 2015, down from 317 GW in 2010, which reflects an 18 GW decline in coal capacity assuming the toxics and transport rules. This decline includes roughly 5 GW of planned retirements and 7 GW of planned coal additions through 2015. Thus, it appears that the EPA is forecasting for 18 GW + 7 GW = 25 GW of coal retirements through 2015, including what is already planned. Please refer to Appendix 2 for a list of EPA's coal retirement projections by unit.

EPA Projects Retirements of Old and Underutilized Plants (As Do We)

	EPA				FBR			
	Specs Exclude New Additions				Specs Exclude New Additions			
Category	Average Age	Average Capacity (MW)	Average Capacity Factor	Retirement Prediction through 2015 (GW)	Average Age	Average Capacity (MW)	Average Capacity Factor	All-in Retirement Prediction (GW)
Retired Units	51	109	56%	25	46	110	54%	45
Operational Units in 2015	44	278	71%	299	42	271	67%	279
Average/Sum	**45**	**265**	**70%**	**324**	**43**	**249**	**65%**	**324**

Source: SNL, EPA, and FBR Research

- **The effective stringency of the proposed rule and subsequent retirements will pivot on EPA's DSI assumptions.** The EPA projects that DSI installations could, in part, be used to remediate HCl and, to a lesser extent, SO2 emissions in lieu of an FGD (thus preempting potential retirements for small coal units). The EPA's forecast reflects 65 GW of DSI installations by 2015, 56 GW of which would be driven by the proposed MACT rule. If DSI proves to be less practical or economic than assumed by the EPA, coal retirements could span a range of 25 GW to 81 GW (25 GW + 56 GW) if no DSI installations take place, which is unlikely. Assuming that half of DSI installations prove practical for what we believe is the addressable market for this technology, then coal retirement estimates could span 25 GW to 53 GW (25 GW + 56 GW/2) using the EPA's methodology. Practical limitations to the use for DSI include the disposal of ash, reliability of the reagent supply chain, and the lack of utility sector experience with this technology. Also, we note that the high variable cost associated with DSI could push down the utilization rate of many coal plants to the point where one would simply retire them.

- **Our coal retirement estimate of 45 GW could be 35 GW if we assume widespread adoption of DSI.** We see roughly 10 GW in capacity among our high-risk plants that could support DSI and thus potentially meet some of the proposed standards.

We Expect Coal Retirements of 45 GW versus EPA's 25 GW

EPA Retirements

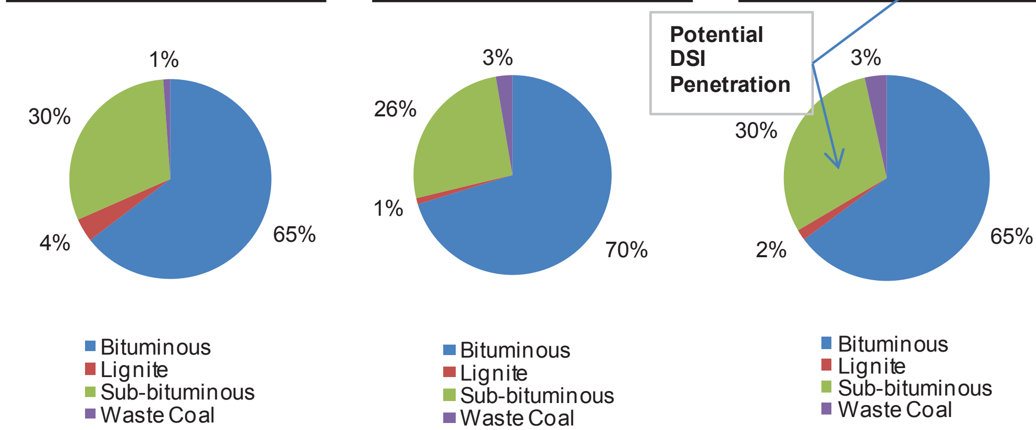
Coal Type	Capacity (MW)
Bituminous	15,979
Lignite	935
Sub-bituminous	7,526
Waste Coal	285
Total	**24,724**

Original FBR Retirements

Coal Type	Capacity (MW)
Bituminous	31,867
Lignite	462
Sub-bituminous	11,831
Waste Coal	1,222
Total	**45,381**

FBR Retirements, Excluding Planned Retirements and Overlapping EPA Retirements

Coal Type	Capacity (MW)
Bituminous	17,597
Lignite	462
Sub-bituminous	8,155
Waste Coal	932
Grand Total	**27,146**



Source: SNL, EPA, and FBR Research

Roughly 10 GW of Our 45 GW Coal Retirement Assumptions Could Be Impacted by DSI

Coal Region	Total Operating Capacity	Avg. Unit Size (MW)	Avg. Year in Service	Avg. Capacity Factor	SO2 Content (lbs/MMBtu)	Likely Use of DSI
N/A	397	66	1968	69	N/A	N/A
CAPP	8,517	131	1962	27	1.2-2.5	Medium
FC	91	46	1976	N/A	1.0-2.5	Low
GC	307	154	1991	81	1.0-2.5	High
ILL	2,249	86	1962	45	3.0-6.0	Low
LIGNITE	155	52	1958	N/A	1.5-4.0	Low
NAPP	7,810	113	1966	41	2.0-4.5	Low
PRB	10,096	102	1966	44	0.5-1.2	High
UINTA	3,673	122	1965	44	1.0-2.5	High
Total	**33,295**	**110**	**1965**	**39**	**1.0-6.0**	

Note: Reflects FBR's forecast and only unplanned retirements.

Source: SNL, EPA, and FBR Research

What Is the Profile of a Top-Performing Plant?

Below is the profile of the top units that overlap in both EPA's top 12% floors for Hg and HCl used to set the proposed emission standards. This analysis was performed for coals with Btu content of 8,300 per lb and above.

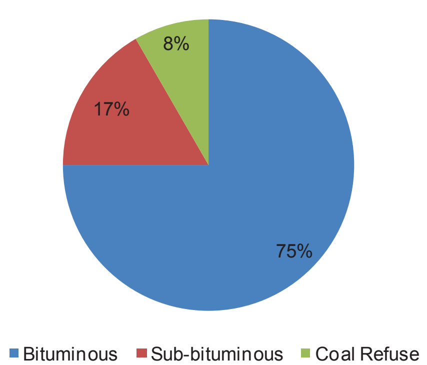
- **Most of these top units employ an FGD and fabric filter. Eleven** out of 12 of the units below use an FGD and fabric filter combination.
- **No units in this group employ DSI to control HCl emissions.** DSI controls were scarce among the top-performing units by category. There were five units with a DSI solely that were in the top 12% of units that determined the HCl floor. No units employing DSI were in the top 12% of units that defined the Hg floor.
- **Few units employ activated carbon injection (ACI) to control mercury emissions.** Only two units burning sub-bituminous coal employ ACI. Most mercury reduction in this group is achieved due to the co-benefits of an FGD/SCR and fabric filter combination.
- About 75% of these top units burn bituminous coal.

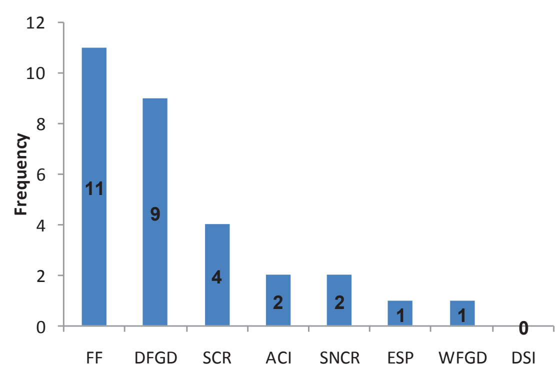
Top-Performing Units That Pass Both of EPA's Proposed Hg and HCl Standards

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	Hg Emissions in lb/MMBtu	HCl Emissions in lb/MMBtu
Joliet 9	JOL5 CONFIG	IL	Conventional Boiler	Cyclone firing	1	326	10.96	Subbituminous	ACI, ESP	7.53E-10	5.41E-04
TS Power Plant	TSPower	NV	Conventional Boiler	Wall firing - opposed firing	1	242	8.73	Subbituminous	SCR, ACI, DFGD, FF	8.67E-10	2.17E-05
Spruance Genco, LLC	GEN2	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	2.63E-09	1.69E-05
Spruance Genco, LLC	GEN3	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	4.69E-09	1.61E-05
Logan Generating Plant	Unit1	NJ	Conventional Boiler	Wall firing - opposed firing	1	242	8.75	Bituminous	SCR, DFGD, FF	5.33E-09	1.29E-05
Seward	SEW-1	PA	Fluidized bed firing	Fluidized bed firing	2	585	10.60	Coal Refuse (culm or gob)	FBC, SNCR, FF	6.35E-09	1.93E-05
Roanoke Valley I	Boiler 1	NC	Conventional Boiler	Wall firing - front firing	1	182	9.34	Bituminous	DFGD, FF	7.26E-09	7.32E-05
Indiantown Cogeneration, L.P.	1	FL	Conventional Boiler	Wall firing - opposed firing	1	361	9.48	Bituminous	SCR, DFGD, FF	8.54E-09	3.58E-05
Roanoke Valley II	Boiler 2	NC	Conventional Boiler	Wall firing - front firing	1	50	11.20	Bituminous	SNCR, DFGD, FF	1.08E-08	3.22E-05
Spruance Genco, LLC	GEN4	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	1.18E-08	3.84E-05
Chambers Cogeneration LP	Boil 1	NJ	Conventional Boiler	Wall firing - front firing	1	285	4.87	Bituminous	SCR, DFGD, FF	1.93E-08	4.24E-05
Clover	Unit 1	VA	Conventional Boiler	Tangential firing	1	431	11.42	Bituminous	FF, WFGD	2.02E-08	3.38E-04

Source: EPA's HCl and Hg ICR Databases and FBR Research

Top Performing Units: 75% Are Bituminous, 92% Use Fabric Filters, and 75% use Dry FGDs





Source: EPA's HCl and Hg ICR Databases and FBR Research

Overview of the EPA's Utility MACT Standards

What Are the EPA's Proposed Requirements?

The EPA has proposed standards for Hg, HCl, and particulate matter based on a sampling of emissions from the best-performing plants in the U.S. EPA collected a stratified sampling of emissions data, including new stack test data, from utilities in 2010 in order to set the MACT standards, or "floors" for coal- and oil-fired boilers. The floors are the statistically-adjusted average of what EPA considers the best-performing 12% of units for each pollutant or surrogate for which EPA has data. EPA accounted for data variability by applying a 99% upper prediction limit (i.e., level of confidence) calculated with a t-test. Best-performing facilities will comply with the "floor" 99% of the time. EPA incorporated past emissions data when available into the variance calculation.

The PM standard is a proxy for capturing non-Hg heavy metals such as Sb, Be, Cd, Cr, Co, Pg, Mn, and Ni. The standard for HCl is also a proxy for removal of acid gases such as HF, HCN, and Cl2, and it also has implications for SO2 removal. EPA simultaneously issued MACT standards for oil-fired utility boilers and performance standards for new coal-fired boilers (the performance standards are superseded by the more stringent MACT standards).

EPA's Emission Limitations As Outlined by the Toxics Rule

Subcategory	Total Particulate Matter	Hydrogen Chloride	Mercury
Existing coal-fired unit designed for coal > 8,300 Btu/lb	0.03 lb/MMBtu (0.2 lb/MWh)	0.002 lb/MMBtu (0.02 lb/MWh)	1 lb/TBtu (0.02 lb/GWh)
Existing coal-fired unit designed for coal < 8,300 Btu/lb	0.03 lb/MMBtu (0.2 lb/MWh)	0.002 lb/MMBtu (0.02 lb/MWh)	11 lb/TBtu (0.2 lb/GWh) 4 lb/Tbtu (0.04 lb/GWh)
Existing - IGCC	0.05 lb/MMBtu (0.3 lb/MWh)	0.0005 lb/MMBtu (0.003 lb/MWh)	3 lb/TBtu (0.02 lb/GWh)
Existing - Solid oil-derived	0.2 lb/MMBtu (2 lb/MWh)	0.005 lb/MMBtu (0.05 lb/MWh)	0.2 lb/TBtu (0.002 lb/GWh)
New coal-fired unit designed for coal > 8,300 Btu/lb	0.05 lb/MWh	0.3 lb/GWh	0.00001 lb/GWh
New coal-fired unit designed for coal < 8,300 Btu/lb	0.05 lb/MWh	0.3 lb/GWh	0.04 lb/GWh
New - IGCC	0.05 lb/MWh	0.3 lb/GWh	0.00001 lb/GWh
New - Solid oil-derived	0.05 lb/MWh	0.0003 lb/MWh	0.002 lb/GWh

Source: EPA Regulatory Impact Analysis

What Are the Paths to Compliance According to the EPA?

Utilities may change fuels and/or install additional control technology to meet the standard, or they may choose to retire if it is more economic for the power sector to meet electricity demand with other sources of generation.

Acid gas emissions (including SO2) can be reduced with flue gas desulfurization or with dry sorbent injection (DSI):

- **Using wet scrubbers.** These FGDs utilize a variety of reagents including crushed limestone, quick lime, and magnesium-enhanced lime and are capable of removing at least 99% of HF/HCl emissions while also achieving 96% SO2 removal.
- **Using dry scrubbers.** These FGDs utilize a lime-based slurry with a downstream fabric filter to remove at least 93% of SO2 while also capturing over 99% of HCL/HF.
- **Using DSI is another possible alternative.** This technology works by injecting an alkaline powdered material directly into flue gas in order to react with the acid gases. The reacted product is then removed by a PM control device such as a baghouse or an ESP. DSI is most efficient with a baghouse present downstream but can be used with ESP. DSI may utilize a variety of sorbents, including trona, sodium carbonate, or calcium carbonate. DSI can also have mercury co-benefits by reducing the amount of SO3 in the flue gas (SO3 interferes with mercury control).

EPA Expects That DSI Could Be Used to Remove HCl for Lower Sulfur Coals

Performance Assumptions	Limestone Forced Oxidation (LSFO) SO2	Limestone Forced Oxidation (LSFO) HCl	Lime Spray Dryer (LSD) SO2	Lime Spray Dryer (LSD) HCl	Dry Sorbent Injection (DSI) SO2	Dry Sorbent Injection (DSI) HCl
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	92% with a floor of 0.065 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	**With fabric filter**: 70% --- **With an electrostatic percipitator:** 50%	**With fabric filter:** 90% with a floor of 0.0001 lbs/MMBtu --- **With an ESP:** 60% with a floor of 0.0001 lbs/MMBtu
Capacity Penalty	-1.65%		-0.70%		-0.65%	
Heat Rate Penalty	1.68%		0.71%		0.65%	
Applicability	Units ≥ 25 MW		Units ≥ 25 MW		Units ≥ 25 MW	
Sulfur Content Applicability			Coals ≤ 2.0% Sulfur by Weight		Coals ≤ 2.0 lb/mmBtu of SO2	
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG		BA, BB, BD, BE, SA, SB, SD, LD, LE, and LG		BA, BB, BD, SA, SB, SD, and LD	

Note: For applicable coal types-first letter is coal rank: B = Bituminous, S = Sub-bituminous, L = Lignite. Second letter is SO2 content (lbs/MMBtu): A = 0.00-0.80, B = 0.81-1.20, D = 1.21-1.66, E = 1.67-3.34, G=3.35-5.00, H> 5.00.

Source: EPA IPM MACT Update

DSI Capital Costs Are Low but Variable Costs Could Be High

Control Type	Heat Rate (Btu/kWh)	SO2 Rate (lb/MMBtu)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	100 MW Capital Cost ($/kW)	100 MW Fixed O&M ($/kW-yr)	300 MW Capital Cost ($/kW)	300 MW Fixed O&M ($/kW-yr)	500 MW Capital Cost ($/kW)	500 MW Fixed O&M ($/kW-yr)	700 MW Capital Cost ($/kW)	700 MW Fixed O&M ($/kW-yr)	1000 MW Capital Cost ($/kW)	1000 MW Fixed O&M ($/kW-yr)
DSI - FF	9,000	2.0	0.64	0.65	6.05	122	2.25	55	0.87	38	0.57	30	0.43	28	0.36
Assuming	10,000	2.0	0.71	0.72	6.72	125	2.28	57	0.89	40	0.58	31	0.43	31	0.38
Bituminous	11,000	2.0	0.79	0.79	7.40	129	2.30	59	0.90	41	0.59	34	0.46	34	0.41
DSI - ESP	9,000	2.0	1.08	1.10	11.23	141	2.41	64	0.94	47	0.64	47	0.57	47	0.52
Assuming	10,000	2.0	1.20	1.22	12.47	145	2.44	66	0.96	52	0.68	52	0.61	52	0.56
Bituminous	11,000	2.0	1.32	1.34	13.72	149	2.48	68	0.98	58	0.73	58	0.65	58	0.60

Source: EPA IPM MACT Update

Mercury capture can be achieved with a full suite of equipment or an ACI:

- **Mercury control depends on speciation.** Upon combustion, mercury exits the furnace in three forms: elemental, oxidized, and as a particulate. Oxidized and particulate mercury are the easiest to control. Elemental mercury is emitted out of the stack; it can be oxidized most effectively with activated carbon that has been brominated. The particulate form is bound to ash and removed by a PM control device such as an ESP or fabric filter (baghouse).
- **Oxidized mercury can be captured by an ACI or FGD system.** A portion of mercury that has converted to oxidized compounds may be removed by either a wet scrubber or by activated carbon injection (ACI) combined with a PM control device.
- **Using a wet FGD system.** A wet FGD can capture oxidized mercury because it is water soluble. Operating a wet FGD/SCR combo with sufficient halogen present will remove more than 90% of the mercury within the flue gas stream.
- **Using an ACI technology.** An ACI provides a unique physical surface to which oxidized mercury can absorb. According to the EPA, ACI has been effective when used with low chlorine coals such as western sub-bituminous. According to the EPA, roughly 90% mercury capture can be achieved with an ACI using a downstream fabric filter. An ESP results in less efficient removal.

EPA Forecast of ACI Fixed and Variable Costs by Unit Size and Heat Rate

					100 MW		300 MW		500 MW		700 MW		1000 MW	
Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
ACI System w / Existing ESP	9,000	0.12	0.12	2.76	32.06	0.13	12.60	0.05	8.16	0.03	6.13	0.03	4.53	0.02
ACI w / SIR of 5 lbs/million acfm	10,000	0.13	0.13	3.07	32.56	0.14	12.80	0.05	8.29	0.03	6.23	0.03	4.60	0.02
Assuming Bituminous Coal	11,000	0.14	0.14	3.38	33.04	0.14	12.99	0.05	8.41	0.04	6.32	0.03	4.67	0.02
ACI System with an Existing Baghouse	9,000	0.05	0.05	2.24	27.93	0.12	10.98	0.05	7.11	0.03	5.34	0.02	3.95	0.02
ACI w / SIR of 2 lbs/million acfm	10,000	0.05	0.05	2.49	28.37	0.12	11.16	0.05	7.23	0.03	5.43	0.02	4.01	0.02
Assuming Bituminous Coal	11,000	0.06	0.06	2.74	28.80	0.12	11.32	0.05	7.33	0.03	5.51	0.02	4.07	0.02
ACI System w / Additional Baghouse	9,000	0.65	0.65	0.50	240	0.91	182	0.69	162	0.61	150	0.57	139	0.53
ACI + Baghouse w / SIR of 2 lbs/million acfm	10,000	0.65	0.66	0.54	259	0.98	197	0.75	176	0.67	163	0.62	151	0.57
Assuming Bituminous Coal	11,000	0.66	0.66	0.58	278	1.05	212	0.80	189	0.72	176	0.67	163	0.62

Note: SIR = Sorbent Injection Rate.

Source: EPA IPM MACT Update

Non-mercury heavy metals and organics are removed by PM control equipment such as fabric filters (FF) and electrostatic precipitators (ESP). Heavy metals like selenium or arsenic and organics that survive the combustion process are non-volatile and bind to the ash. Both ESPs and fabric filters are capable of removing more than 99% of particulates greater than 2.5 microns in size (PM2.5).

- **Using an ESP.** ESPs are designed for specific fuels; while they require less energy to run than fabric filters, they are less flexible for fuel switching. Increases in gas flow rate, ash resistivity, or particle loading resulting from fuel switching or blending can compromise the performance of ESPs according to EPA documentation.
- **Using a fabric filter.** Fabric filters (a.k.a. baghouses) do not have the same design limitations as an ESP. They also have significant mercury and acid gas co-benefits when used with an FGD, DSI, or ACI. If a unit already has an ESP technology, it can either upgrade its precipitator technology to be more flexible, or alternatively, install a fabric filter.

EPA Estimates of Baghouse (Fabric Filter) Costs by Unit Size and Heat Rate

					100 MW		300 MW		500 MW		700 MW		1000 MW	
Coal Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
	9,000				188	0.8	153	0.6	139	0.6	130	0.6	122	0.5
Bituminous	10,000	0.60	0.60	0.15	205	0.9	167	0.7	151	0.6	141	0.6	132	0.6
	11,000				221	0.9	180	0.8	163	0.7	153	0.6	143	0.6

Source: EPA IPM MACT Update

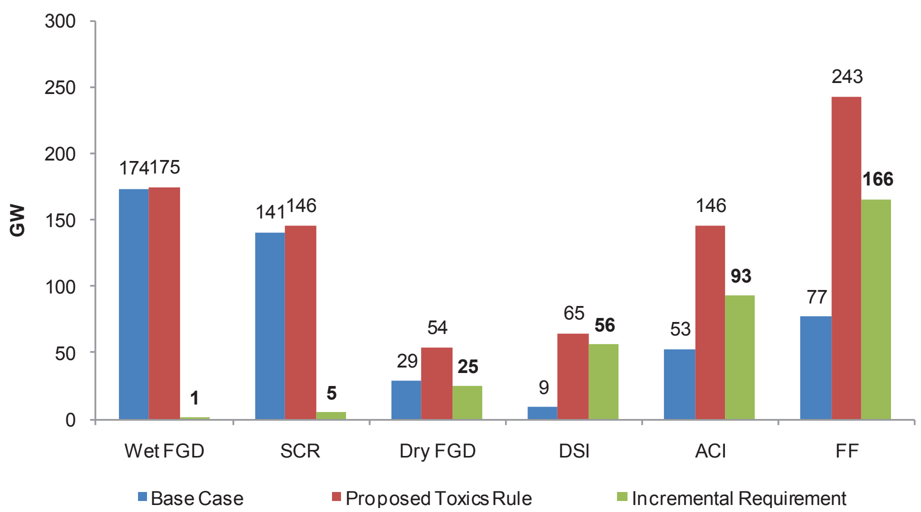
How Does the EPA See Compliance Unfold?

EPA's proposal reflects up to $210 billion in costs through 2030. The EPA estimates that its proposed rules would result in the retrofits shown below, with an annual cost of $10 billion, including approximately $2.9 billion for fuel and $3 billion in additional fixed and variable costs. Roughly $5 billion annually represents amortization of capital through 2030; this amounts to about $200 billion in costs though 2030. EPA projects that this would increase electric rates by approximately 3.7% by 2015.

EPA's proposal reflects 25 GW of retirements, but that is likely the minimum. Under the EPA's scenario, coal capacity declines from 317 GW to 299 GW between 2010 and 2015. The implied retirement number appears to be roughly 25 GW of capacity, including 7 GW of new additions. Retired units have an average age of 51 years, average capacity of 109 MW, and capacity factor of 56%.

EPA sees an industry shift to higher sulfur and chlorine content coals. EPA believes that new control technology retrofits will allow the industry to rely more heavily on local bituminous coal in the eastern and central U.S. that have higher contents of HCl and sulfur, and that is less expensive to transport than western sub-bituminous coal. Under EPA's proposed rule, the demand for bituminous coals increases and the demand for sub-bituminous and lignite coals is reduced slightly. The EPA assumes that the decline in lignite use will reflect a decrease in generation from lignite-fired boilers coupled with a general shift toward sub-bituminous for boilers that were previously burning lignite coal in EPA's base case.

EPA Sees Toxics Rule Driving Sharp Increase in Installation of DSI and Fabric Filters



Source: EPA Regulatory Impact Analysis

DSI May Be Required to Avoid Heavy Coal Retirements

DSI is a key component to meeting the EPA's proposed rules, and its widespread adoption has the potential to limit coal retirements. If DSI were employed widely, we estimate that our coal retirement figure would drop from 45 GW to about 35 GW. EPA appears to be forecasting widespread adoption of DSI, and its forecast includes 65 GW of installation by 2015, 56 GW of which would be driven by the MACT rule. By 2015, the EPA envisions that the coal fleet would be 299 GW, down from 317 GW in 2010. Controls for SO2 and HCl would be achieved using 229 GW of FGDs and 65 GWs in DSIs, in conjunction with 243 GW of fabric filters to collect by-products. However, widespread adoption of DSI is not a foregone conclusion and seems to be a matter of debate.

DSI could be used to meet stringent HCl standards for units that do not require a steep SO2 reduction. DSI has enjoyed limited use in the U.S. so far. However, the technology could become increasingly important when EPA adopts the first federal HCl standard. DSI could be employed to control HCl emissions for smaller coal units in lieu of a scrubber, assuming sulfur content is sufficiently low, and provided resulting SO2 emissions comply with subsequent standards.

However DSI is not always practical for high sulfur coals, which could limit its widespread applicability. According to a Sargent & Lundy's consulting analysis used by EPA, the DSI system *"should not be applied to fuels with a sulfur content of greater than 2 lb SO2/MMBtu."* Based on checks with suppliers, this appears to be the case. DSI captures SO2 in conjunction with HCl. If sulfur concentrations in the emissions are too high, it becomes difficult to capture the resulting by-products. It can also be uneconomical to purchase the needed reagents and dispose of the additional waste product.

Medium/High Sulfur Bituminous Coal Exceeds the 2 lbs/MMBtu Level Appropriate for DSI

Coal Type by Sulfur Grade	Sulfur Emission Factors (lbs/MMBtu)	Mercury Emission Factors (lbs/TBtu)	Applicable Coal Basins by Sulfur Grade
Low Sulfur Eastern Bituminous	0.69	3.78	
Low Sulfur Western Bituminous	1.08	3.34	Colorado
Low Medium Sulfur Bituminous	1.43	12.00	CAPP
Medium Sulfur Bituminous	2.54	13.98	CAPP, ILB
High Sulfur Bituminous	3.98	13.82	NAPP, ILB
High Sulfur Bituminous	6.20	18.67	ILB
Low Sulfur Subbituminous	0.60	4.93	PRB
Low Sulfur Subbituminous	0.94	6.44	PRB
Low Medium Sulfur Subbituminous	1.41	4.43	PRB
Low Medium Sulfur Lignite	1.54	9.76	
Medium Sulfur Lignite	2.63	10.68	
High Sulfur Lignite	3.91	14.88	

Source: EPA's HCl Database and FBR Research

The EPA forecast for DSI installations appears to reflect a large portion of the addressable market. We estimate an addressable market size of 58 GW for DSI installations by taking the EPA's dataset for unscrubbed coal capacity and subtracting expected retirements and high sulfur emitting units. Admittedly, some DSI could be installed for bituminous units in theory. Based on this addressable market size, the EPA assumption of 56 GW in additional DSI installations appears to correspond to a full penetration of the addressable market for this product.

We Estimate That the Addressable DSI Market Is Roughly 58 GW of Capacity

Category	Capacity (GW)
Unscrubbed Capacity	120
-EPA Mandated Retirements	-22
-Units Potentially Incompatible with DSI	-40
Addressable DSI Market	**58**

Source: EPA's Retirement Database, NEEDS database, and FBR Research

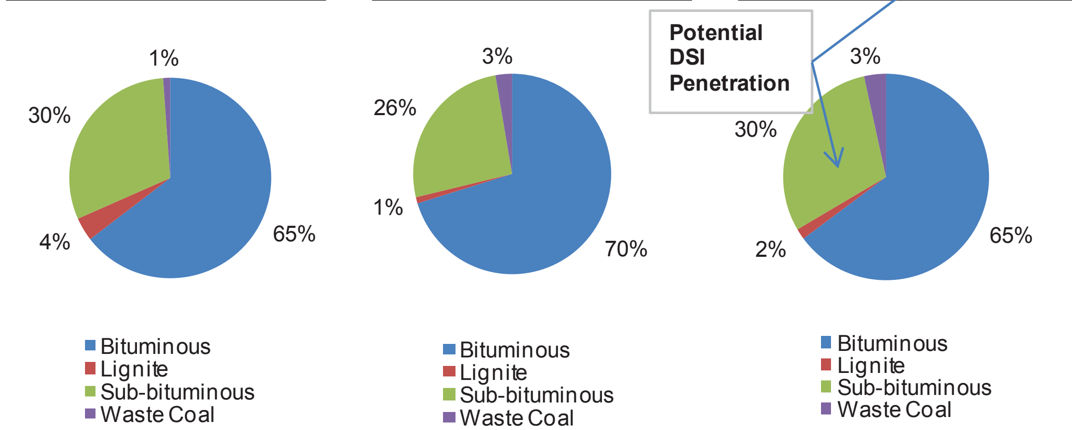
Our coal retirement estimate of 45 GW could be 35 GW if we assume widespread adoption of DSI. We see roughly 10 GW in capacity among our high-risk plants that could support DSI and thus potentially meet some of the proposed standards.

We Expect Coal Retirements of 45 GW versus EPA's 25 GW

EPA Retirements	
Coal Type	**Capacity (MW)**
Bituminous	15,979
Lignite	935
Sub-bituminous	7,526
Waste Coal	285
Total	**24,724**

Original FBR Retirements	
Coal Type	**Capacity (MW)**
Bituminous	31,867
Lignite	462
Sub-bituminous	11,831
Waste Coal	1,222
Total	**45,381**

FBR Retirements, Excluding Planned Retirements and Overlapping EPA Retirements	
Coal Type	**Capacity (MW)**
Bituminous	17,597
Lignite	462
Sub-bituminous	8,155
Waste Coal	932
Grand Total	**27,146**



Source: SNL, EPA, and FBR Research

Roughly 10 GW of our 45 GW Coal Retirement Assumptions Could Be Impacted by DSI

Coal Region	Total Operating Capacity	Avg. Unit Size (MW)	Avg. Year in Service	Avg. Capacity Factor	SO2 Content (lbs/MMBtu)	Likely Use of DSI
N/A	397	66	1968	69	N/A	N/A
CAPP	8,517	131	1962	27	1.2-2.5	Medium
FC	91	46	1976	N/A	1.0-2.5	Low
GC	307	154	1991	81	1.0-2.5	High
ILL	2,249	86	1962	45	3.0-6.0	Low
LIGNITE	155	52	1958	N/A	1.5-4.0	Low
NAPP	7,810	113	1966	41	2.0-4.5	Low
PRB	10,096	102	1966	44	0.5-1.2	High
UINTA	3,673	122	1965	44	1.0-2.5	High
Total	**33,295**	**110**	**1965**	**39**	**1.0-6.0**	

Note: Reflects FBR's forecast and only unplanned retirements.

Source: SNL, EPA, and FBR Research

Currently DSI is not widely used, even among top-performing plants that set the HCl floor. Among EPA's top 12% of units that set the floor for HCl, we find that 15 currently use DSI. Of those 15, we identify five that use DSI without an FGD. Of those five, only one unit uses bituminous coal. We performed the same analysis on the coal units that are still within the HCl limit but outside of the top 12% HCl floor. Of the 46 additional units that pass the HCl emission test, we found that six employ the DSI technology. Of those six, only four use DSI without an FGD, and only one plant uses bituminous coal (and it barely meets the emission standard at .002 lb/MMBtu). In summary, we know of only nine units in the U.S. that use a DSI technology without an FGD and pass the HCl test, and only two of those plants use bituminous coal.

Only Five Units Among the 131 That Define the HCl Floor Employ Solely DSI to Control HCL

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	HCl Emissions in lb/MMBtu
Cardinal	CD-U1	OH	Conventional Boiler	Wall firing - opposed firing	1	615	8.57	Bituminous	SCR, DSI, ESP, WFGD	1.43E-04
Conesville	CV-4	OH	Conventional Boiler	Tangential firing	1	842	9.46	Bituminous	SCR, ESP, DSI, WFGD	1.63E-04
Ghent	GH1	KY	Conventional Boiler	Tangential firing	1	520	12.09	Bituminous	SCR, DSI, ESP, WFGD	1.80E-04
Cardinal	CD-U2	OH	Conventional Boiler	Wall firing - opposed firing	1	615	8.57	Bituminous	SCR, DSI, ESP, WFGD	1.85E-04
Mountaineer	Mt-1	WV	Conventional Boiler	Wall firing - opposed firing	1	1320	9.06	Bituminous	SCR, DSI, ESP, WFGD	2.14E-04
Arapahoe	Unit 3	CO	Conventional Boiler	Vertical firing	1	48	15.73	Subbituminous	DSI, FF	2.18E-04
Cherokee	Unit 1	CO	Conventional Boiler	Vertical firing	1	117	11.90	Bituminous	DSI, FF	2.25E-04
Gibson	4	IN	Conventional Boiler	Wall firing - opposed firing	1	661	9.48	Bituminous	SCR, DSI, ESP, WFGD	2.61E-04
Montrose	2	MO	Conventional Boiler	Tangential firing	1	188	11.33	Subbituminous	DSI, ESP	3.00E-04
Montrose	1	MO	Conventional Boiler	Tangential firing	1	188	11.38	Subbituminous	DSI, ESP	3.00E-04
Montrose	3	MO	Conventional Boiler	Tangential firing	1	188	11.97	Subbituminous	DSI, ESP	3.00E-04
Cumberland	1	TN	Conventional Boiler	Wall firing - opposed firing	1	1300	10.87	Bituminous	SCR, DSI, ESP, WFGD	3.17E-04
Cumberland	2	TN	Conventional Boiler	Wall firing - opposed firing	1	1300	10.87	Bituminous	SCR, DSI, ESP, WFGD	3.35E-04
Ghent	GH3	KY	Conventional Boiler	Wall firing - opposed firing	1	525	11.18	Bituminous	DSI, ESP, SCR, WFGD	5.27E-04
East Bend Station	2	KY	Conventional Boiler	Wall firing - front firing	1	651	9.70	Bituminous	DSI, ESP, SCR, WFGD	5.28E-04

Source: EPA's HCl and Hg ICR Databases and FBR Research

An Additional Four "DSI-Only" Plants Meet the HCl Floor

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	HCl Emissions in lb/MMBtu
Ghent	GH4	KY	Conventional Boiler	Wall firing - opposed firing	1	525	11.37	Bituminous	DSI, ESP, SCR, WFGD	6.97E-04
W H Zimmer	1	OH	Conventional Boiler	Wall firing - opposed firing	1	1408	8.99	Bituminous	DSI, SCR, ESP, WFGD	8.78E-04
Dunkirk Generating Plant	1	NY	Conventional Boiler	Tangential firing	1	85	10.85	Subbituminous	SNCR, DSI, FF	9.13E-04
Dunkirk Generating Plant	4	NY	Conventional Boiler	Tangential firing	1	195	9.42	Subbituminous	SNCR, DSI, FF	9.67E-04
Potomac River	4	VA	Conventional Boiler	Tangential firing	1	108	8.90	Bituminous	DSI, ESP	1.13E-03
Potomac River	1	VA	Conventional Boiler	Tangential firing	1	93	10.43	Bituminous	DSI, ESP	1.81E-03

Source: EPA's HCl and Hg ICR Databases and FBR Research

Some Units Use DSI but Don't Comply With the Stated HCl Standard

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	HCl Emissions in lb/MMBtu
Potomac River	3	VA	Conventional Boiler	Tangential firing	1	108	8.90	Bituminous	DSI	6.15E-03
Arapahoe	Unit 4	CO	Conventional Boiler	Vertical firing	1	118	14.49	Subbituminous	DSI	1.12E-02
General James M. Gavin	GA-2	OH	Conventional Boiler	Wall firing - opposed firing	1	1320	9.04	Bituminous	DSI; WFGD	1.15E-02
General James M. Gavin	GA-1	OH	Conventional Boiler	Wall firing - opposed firing	1	1320	9.04	Bituminous	DSI; WFGD	4.56E-02

Source: EPA's HCl Database and FBR Research

Impact of Retirements on Coal Demand

Given the uncertainty surrounding the widespread adoption of DSI, it is a little premature to further refine our previous estimate of a 52 MT impact on the coal burn. However, if the DSI technology is not applied to coals with sulfur content greater than 2 lbs SO2/MMBtu then high sulfur bituminous coals (NAPP and ILB) will have to be deployed to plants with existing or proposed scrubbing facilities. We note that currently these two regions produce about 236 MTs of coal and represent about 21% of the existing coal supply.

Coal Production and Sulfur Content by Region

Region	2010 Production (MTs)	Sulfur Content (lbs/ MMBTU)
PRB	487	0.5-1.2
NAPP	130	2.0-4.5
CAPP	185	1.2-2.5
ILB	106	3.0-6.0
Western Bit	73	1.0-2.5

Source: SNL and FBR Research

Based on our initial analysis of 45 GW of retirements, we came up with 52 MTs of incremental coal burn being affected. Now if the use of DSI reduces the retirement number to 35 GW, and we assume most of the sub-bituminous (PRB) coal plants will not retire, then the actual impact on coal could be even lower at 43 MTs. Regionally, this should be viewed as a positive for PRB and a negative for NAPP and ILB.

Impact of 45 GW of Retirements on Coal Demand

		Effective Capacity (MW)		Coal (MTs) Impacted	
Regions	No. of Units	2009	3-yr Average	2009	3-yr Average
NAPP	84	3,205	4,915	13	20
CAPP	107	3,759	6,610	16	28
PRB	119	3,897	5,729	23	34
W.Bit	40	1,517	2,323	7	11
ILB	29	855	1,198	4	6
Others	11	431	485	3	4
Total	**390**	**13,664**	**21,261**	**66**	**102**
Net impact after migration to higher utilization plants				52	

Note: The 3-yr average is based on average capacity factors for 2007-2009 period

Source: EIA, SNL, and FBR Research

Mercury Standard Appears to be Readily Achievable

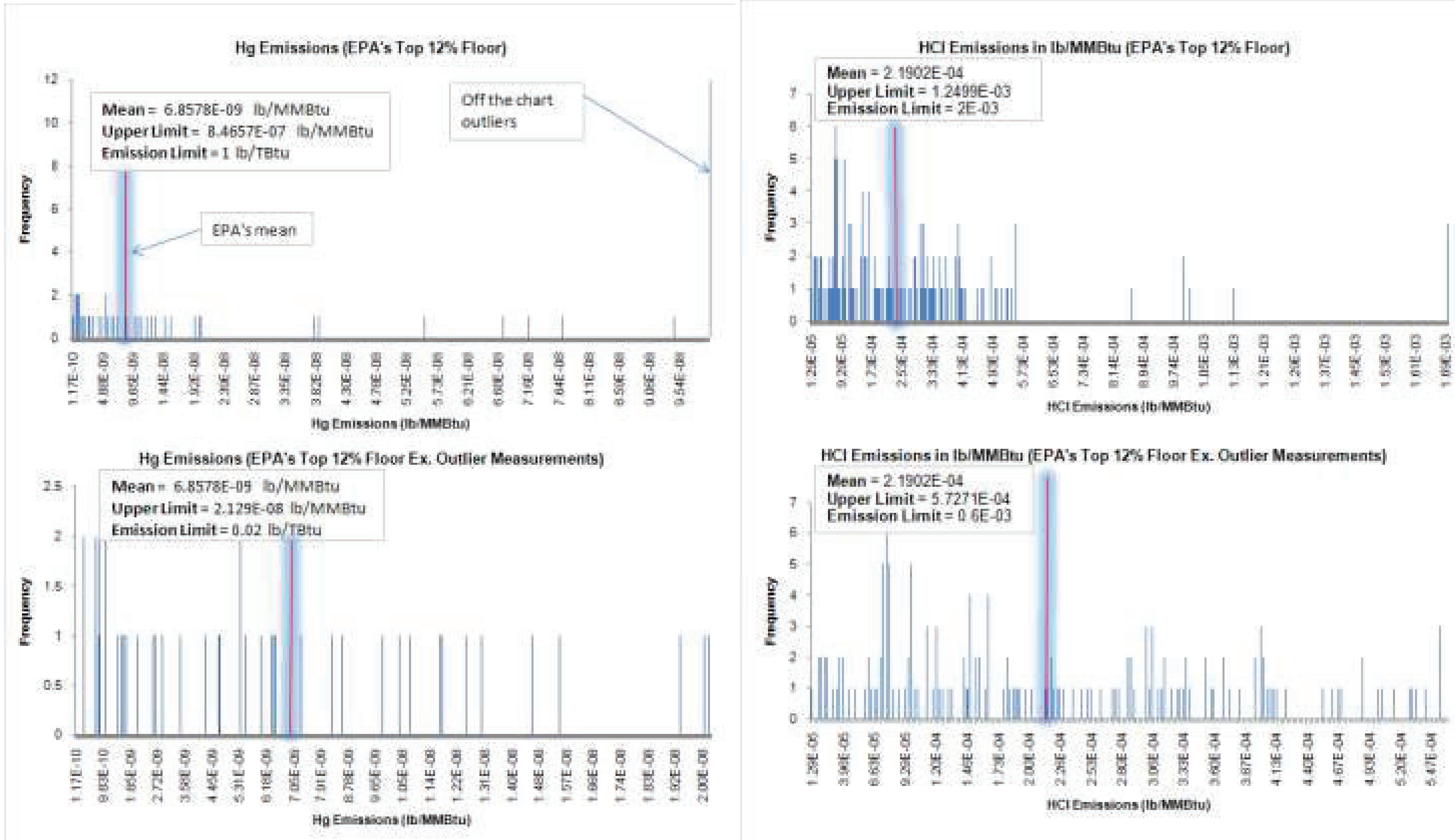
The Hg limit appears relatively easier to meet based on our review of the underlying data used to set the mercury floor. This data, which was collected as part of an EPA Information Collection Request (ICR), shows a high variance. Based on our preliminary analysis that has not been vetted with the EPA at this time, it appears that this variance tends to lower the emission threshold for emitting plants. While 40 units were used to define the Hg floor (top 12%) for coals >8,300 Btu/lb, it turns out that roughly 149 of the 330 units sampled meet the proposed Hg standard. Nonetheless, the current standard still requires remediation equipment.

- **Mercury standard appears readily achievable.** The standard for Hg proposed for coals above 8,300 Btu/lb is 1.0 lb/TBtu. Top 12% units with a heat rate >8,300 Btu/lb tested for Hg emissions had an average emission rate of $6.86*10^{-3}$ lbs/TBtu (excluding outlier tests), with all measurement tests (including outliers) varying between $1.17*10^{-4}$ lb/TBtu and 1.61 lb/TBtu, with standard deviation of 0.34 lbs/TBtu.
- **Uncontrolled emissions vary significantly by coal type.** Uncontrolled Hg emissions tend to be around 5 lb/TBtu, varying widely between 1 lb/TBtu and 19 lbs/TBtu depending on the coal. Lignite tends to be in the 13 lb/TBtu to 14 lb/TBtu range. Low medium sulfur bituminous is 5.38 lb/TBtu, high sulfur bituminous is roughly 7 lb/TBtu, and low sulfur western bituminous is 1.82 lb/TBtu.
- **Mercury emissions will still need to be controlled, even with this standard.** Hg emissions can be reduced by operating a wet FGD for SO_2 control alongside selective catalytic reduction (SCR) for NO_x control, with sufficient halogen present. A cheaper option is to install activated carbon injection (ACI) on units without FGDs. This will remove more than 90% of the mercury using a downstream fabric filter. Our understanding is that an electrostatic precipitator (or ESP) results in less efficient mercury removal with ACI.

The proposed HCl floor appears tougher to meet based on the variance in the ICR data. While 131 units set the HCl floor, roughly 171 of the 1,091 units sampled passed the test. Thus, we believe that the HCl standard could be interpreted as more stringent on this basis than the mercury standard.

- **The proposed HCl emission standard appears relatively tight**. For existing coal units, the proposed emission standard is $2*10^{-03}$lb/MMBtu. Top 12% of units tested for HCl emissions average $2.19*10^{-04}$ lb/MMBtu (excluding outlier tests), with all measurement tests (including outliers) varying between $1.29*10^{-05}$ and $3.60*10^{-3}$, with a standard deviation of $4.36*10^{-04}$. Uncontrolled units appear to emit $3*10^{-02}$ lb/MMBtu.
- **Typical HCl emissions for the U.S. fleet are not available to our knowledge, but compliance will require capital investment based on the profile of the highest-performing units (previously discussed).** According to the EPA, current wet scrubber technology is capable of removing at least 99% of hydrogen fluoride (HF) and hydrogen chloride (HCl) emissions while also achieving 96% SO_2 removal. Dry FGD technology with a downstream fabric filter could remove at least 93% SO_2 while also capturing over 99% HCL and HF. As an alternative to an FGD, the EPA proposes the use of a DSI, which injects an alkaline powdered material directly into the flue gas. The reacted product is then removed by a particulate matter control device, such as a baghouse downstream. As discussed in greater detail earlier in this note, debate over the utility MACT's retirement and retrofit impacts centers on the economics of widespread DSI deployment. The relative superiority of FGD for SO_2 control suggests that units vulnerable to tightening SO_2 standards are more likely to either install FGD or retire, than to install DSI.

Removing Outliers from the 12% Floor Results in 40x and 2x Stricter Hg and HCl Standards, Respectively



Source: EPA's HCl and Hg ICR Databases and FBR Research

Policy Overview: EPA Rulemaking for Coal Generation

EPA finalizing four rules affecting coal power. The Obama EPA has announced its intention to move forward with a number of environmental rulemakings that will pressure coal-fired electric generators to add environmental control technology or shut down. The four pending rules that should receive the most attention are the Clean Air Transport Rule (CATR), the air toxics rule for utilities (MACT—maximum achievable control technology), the proposed rule for coal combustion residuals (CCRs, also known as fly ash) regulation, and the cooling water intake structures rule. This report examines the likely impact of the clean air rules that are expected this year under consent decrees.

Ash and intake rules down the road. According to an analysis from the North American Electric Reliability Corp, the four rules combined could lead to the retirement of up to 78 GW of power generation depending on the requirements. Although strict regulations for coal ash and intake could lead to significant costs, EPA has responded by signaling that it intends to provide flexibility for operators to comply with ash and intake rules, implying low compliance costs. EPA has until March 28 to publish a draft intake rule, and final action is scheduled for July 27, 2010, according to a settlement. Likewise, EPA proposed two options for regulating coal ash in June 2010, but due to the large volume of public comments, it is not expected to finalize the rule until 2012. EPA Administrator Jackson has indicated that the rule would allow for beneficial reuse, a key cost factor.

MACT time lines are also aggressive, but implementation is flexible. Under a consent decree, EPA is required to finalize the rule by November 16, 2011. Under the law, EPA can allow up to three years for compliance or November 16, 2014. The failure to comply with MACT limits could carry civil penalties up to $37,500 per day and an injunction prohibiting operation of the unit. The Clean Air Act allows an additional one-year waiver to install pollution controls on a case-by-case basis. We also note that the consent decree allows EPA to ask the court for more time. Our EPA contacts suggest that they take the deadlines seriously and intend to meet them. However, we note that a large number of public comments or new data could lead EPA to ask for more time.

Transport rule likely to be modified. EPA is scheduled to finalize its transport rule this summer. The transport rule aims to reduce emissions of sulfur dioxide (SO2) and nitrogen oxide (NOx) from power plants located in 31 states and the District of Columbia. The rule is designed to prevent pollution from upwind states contributing to clean air violations in downwind states. Under EPA's proposal, each state would be given an emissions budget (statewide cap) and required to implement policies to ensure that emissions do not exceed authorized levels. Unlike the rule's predecessor, CAIR, trading between states would be significantly limited. This would raise compliance costs and increase pressure on utilities in certain high-emission states. In July 2010, EPA published a draft transport rule, with implementation scheduled to begin on January 1, 2012. Our conversations suggest that EPA is likely to modify the proposed rules to reduce reduction/shutdown pressure on transport states, especially in the Midwest. However, transport rule emission limits are expected to tighten again in 2014 following a planned revision of standards for fine particulate matter and ozone. A subsequent transport rule could focus on sectors beyond the electric generating units.

Public Policy Factors Put Downward Pressure on Retirements

The release of the draft MACT is the starting gun for public negotiations over the stringency and design of Clean Air Act regulations. EPA's analysis reflects a relatively soft impact due largely to the adoption of DSI. We expect some utilities, major consumers of energy, and labor unions to push back on EPA's analysis, arguing that the standards are likely to lead to more widespread plant retirements and higher energy prices. EPA will address these comments as it drafts the final regulations scheduled to be published in November. EPA may adopt further flexibility mechanisms depending on the results of analyses and advocacy efforts. We see a number of factors leading to a more gradual plant closure than one might expect given a plain reading of the Clean Air Act.

Intense political pressure to maintain low-cost power in coal/manufacturing regions. Our analysis suggests that unemployment in the politically sensitive and energy-intensive swing states of the

Midwest dampens the desirability of significant coal retirement and power price appreciation. Much of the unscrubbed capacity is in the coal-producing and consuming regions of the industrial Northeast and upper Midwest, which is also the key electoral swing region in the U.S.

Discretion to allow continued plant operation. The MACT could require less than universal application of environmental controls for implementing, measuring, and monitoring MACT standards. EPA has some discretion in how to measure the emissions to be controlled. Certain designs such as longer measurement periods or measurements of concentrations rather than volumes could allow certain facilities to reach the MACT standard without applying the entire suite of controls needed at other facilities. In designing the MACT regulation, EPA may also "distinguish among classes, types, and sizes of sources within a category or subcategory" when establishing MACT standards. Therefore, EPA could set a different MACT standard based on the size of the facility, the type of fuel, the type of plant, or a number of other factors that could allow certain plants to remain operational for some time after the statutory deadline. Most notably, EPA has resisted the idea of creating subcategories of regulation by coal type, but political pressure to avoid shutdowns could force the agency to reconsider. This is a key issue with the boiler MACT, which we understand may be illustrative of the utility MACT dynamic.

MACT includes years of possible extensions. The Clean Air Act offers additional opportunities to push back the timing of shutdowns. Under the law, the EPA administrator or state-approved program can grant a one-year extension if more time is "necessary for the installation of controls." Likewise, the President can grant an extension for up to two years if technology to implement standards is not available and it is in the interest of national security.

Legal challenges to pending regulations. Litigation appears to be the rule rather than the exception when it comes to Clean Air Act regulation. Our conversations with industry sources suggest a willingness to postpone final decisions on reacting to the Clean Air regulations until after the rules are finalized and have been challenged in court. Although at this time we do not expect that the final rules would be stayed by a court, we note the significant risk that litigation delays pose to the compliance deadlines. We also note the potential for delays if, following litigation, utilities apply control technology on a rushed schedule, creating a shortage of scrubber installation capacity.

Reliability barriers to shutdowns. Our conversations with policy analysts indicate that investors should not anticipate region-wide reliability impacts. A more nuanced perspective on reliability, however, suggests that transmission security can be a highly local issue (for example, a small uncontrolled power plant with no impact on regional reliability but that is essential to maintain voltage on a local transmission line). If retiring such plants would create service concerns for isolated populations or industries, we would expect significant local and Congressional political resistance.

Appendix 1: List of Plants That Define the Top 12% by Category

In the following several pages, we list out EPA's top 12% HCl and Hg floors with least emitting units.

Generation Units Used in Determining EPA's Hg Floor

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	Hg Emissions in lb/MMBtu
Deepwater	Coal-firing	NJ	Conventional Boiler	Wall firing - front firing	1	87	9.43	Bituminous	DSI, SNCR, FF	1.17E-10
Dallman	32	IL	Conventional Boiler	Cyclone firing	1	84	10.79	Bituminous	SCR, ESP, WFGD	3.71E-10
Dallman	31	IL	Conventional Boiler	Cyclone firing	1	90	10.69	Bituminous	SCR, ESP, WFGD	3.74E-10
Will County	WC4CONFIG	IL	Conventional Boiler	Tangential firing	1	542	9.69	Subbituminous	ACI, ESP	7.50E-10
Joliet 9	JOL5 CONFIG	IL	Conventional Boiler	Cyclone firing	1	326	10.96	Subbituminous	ACI, ESP	7.53E-10
Escalante	1	NM	Conventional Boiler	Tangential firing	1	260	9.10	Subbituminous	FF, WFGD	8.06E-10
TS Power Plant	TSPower	NV	Conventional Boiler	Wall firing - opposed firing	1	242	8.73	Subbituminous	SCR, ACI, DFGD, FF	8.67E-10
Waukegan	WK8CONFIG	IL	Conventional Boiler	Tangential firing	1	383	10.34	Subbituminous	ACI, ESP	8.69E-10
Dallman	33	IL	Conventional Boiler	Tangential firing	1	208	10.05	Bituminous	SCR, ESP, WFGD	1.06E-09
Crawford	CRA7 CONFIG	IL	Conventional Boiler	Tangential firing	1	234	10.16	Subbituminous	ACI, ESP	1.42E-09
Joliet 29	JOL8CONFIG	IL	Conventional Boiler	Tangential firing	2	542	10.03	Subbituminous	ACI, ESP	1.64E-09
St. Nicholas Cogen Project	1	PA	Fluidized bed firing	Fluidized bed firing	1	99	13.10	Coal Refuse (culm or gob)	FBC, FF, WFGD	2.06E-09
Joliet 29	JOL7CONFIG	IL	Conventional Boiler	Tangential firing	2	546	10.19	Subbituminous	ACI, ESP	2.55E-09
Spruance Genco, LLC	GEN2	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	2.63E-09
Will County	WC3CONFIG	IL	Conventional Boiler	Tangential firing	1	278	9.29	Subbituminous	ACI, ESP	2.85E-09
Fisk	FISK19 CONFIG	IL	Conventional Boiler	Tangential firing	1	348	10.30	Subbituminous	ACI, ESP	3.44E-09
Powerton	Pow5CONFIG	IL	Conventional Boiler	Cyclone firing	2	810	9.98	Subbituminous	ACI, ESP	4.23E-09
Powerton	Pow6CONFIG	IL	Conventional Boiler	Cyclone firing	2	812	9.92	Subbituminous	ACI, ESP	4.25E-09
Spruance Genco, LLC	GEN3	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	4.69E-09
Nucla	001	CO	Fluidized bed firing	Fluidized bed firing	1	110	9.38	Bituminous	FBC, SNCR, FF	5.33E-09
Logan Generating Plant	Unit1	NJ	Conventional Boiler	Wall firing - opposed firing	1	242	8.75	Bituminous	SCR, DFGD, FF	5.33E-09
Waukegan	WK7CONFIG	IL	Conventional Boiler	Tangential firing	1	345	10.10	Subbituminous	ACI, ESP	5.51E-09
Seward	SEW-1	PA	Fluidized bed firing	Fluidized bed firing	2	585	10.60	Coal Refuse (culm or gob)	FBC, SNCR, FF	6.35E-09
Avon Lake	AL10	OH	Conventional Boiler	Tangential firing	1	101	14.33	Bituminous		6.42E-09
AES Greenidge	Unit 4	NY	Conventional Boiler	Tangential firing	1	112	9.97	Bituminous, Petroleum Coke	SCR, ACI, DFGD, FF	6.46E-09
Roanoke Valley I	Boiler 1	NC	Conventional Boiler	Wall firing - front firing	1	182	9.34	Bituminous	DFGD, FF	7.26E-09
Avon Lake	AL12-2	OH	Conventional Boiler	Wall firing - opposed firing	1	680	9.68	Bituminous	SNCR, ESP	8.27E-09
Indiantown Cogeneration, L.P.	001	FL	Conventional Boiler	Wall firing - opposed firing	1	361	9.48	Bituminous	SCR, DFGD, FF	8.54E-09
Northampton Generating Company, L.P.	GEN1	PA	Fluidized bed firing	Fluidized bed firing	1	121	9.47	Coal Refuse (culm or gob)	FBC, SNCR, FF	1.04E-08
Roanoke Valley II	Boiler 2	NC	Conventional Boiler	Wall firing - front firing	1	50	11.20	Bituminous	SNCR, DFGD, FF	1.08E-08
AES Hawaii	001	HI	Fluidized bed firing	Fluidized bed firing	1	203	5.03	Bituminous	FBC, SNCR, FF	1.17E-08
Spruance Genco, LLC	GEN4	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	1.18E-08
Ebensburg Power Company	EPC01	PA	Fluidized bed firing	Fluidized bed firing	1	58	14.31	Coal Refuse (culm or gob)	FBC, FF, WFGD	1.25E-08
AES Hawaii	002	HI	Fluidized bed firing	Fluidized bed firing	1	203	4.65	Bituminous	FBC, SNCR, FF	1.30E-08
Colver Power Project	AAB01	PA	Fluidized bed firing	Fluidized bed firing	1	131	10.95	Coal Refuse (culm or gob)	FBC, SNCR, FF	1.46E-08
Birchwood Power Facility	1A	VA	Conventional Boiler	Tangential firing	1	222	10.36	Bituminous	SCR, DFGD, FF	1.55E-08
Valley	VAPP-B1	WI	Conventional Boiler	Wall firing - front firing	2	144	12.06	Bituminous	FF, WFGD	1.93E-08
Chambers Cogeneration LP	Boil 1	NJ	Conventional Boiler	Wall firing - front firing	1	285	4.87	Bituminous	SCR, DFGD, FF	1.93E-08
Reid Gardner	1	NV	Conventional Boiler	Wall firing - front firing	1	111	10.95	Bituminous	FF, WFGD	2.01E-08
Clover	Unit 1	VA	Conventional Boiler	Tangential firing	1	431	11.42	Bituminous	FF, WFGD	2.02E-08

Source: EPA's ICR Database

Generation Units Used in Determining EPA's HCl Floor – Top 51 Units Don't Employ DSI

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	HCl Emissions in lb/MMBtu
Logan Generating Plant	Unit1	NJ	Conventional Boiler	Wall firing - opposed firing	1	242	8.75	Bituminous	SCR, DFGD, FF	1.29E-05
Spruance Genco, LLC	GEN3	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	1.61E-05
Spruance Genco, LLC	GEN2	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	1.69E-05
Seward	SEW-1	PA	Fluidized bed firing	Fluidized bed firing	2	585	10.60	coal refuse (culm or gob)	FBC, SNCR, FF	1.93E-05
Seward	SEW-2	PA	Fluidized bed firing	Fluidized bed firing	2	585	10.60	coal refuse (culm or gob)	FBC, SNCR, FF	1.93E-05
Sandow Station	5A	TX	Fluidized bed firing	Fluidized bed firing	1	282	10.48	Lignite	FBC, SNCR, ACI, DFGD, FF	2.12E-05
TS Power Plant	TSPower	NV	Conventional Boiler	Wall firing - opposed firing	1	242	8.73	Subbituminous	SCR, ACI, DFGD, FF	2.17E-05
Sandow Station	5B	TX	Fluidized bed firing	Fluidized bed firing	1	282	10.48	Lignite	FBC, SNCR, ACI, DFGD, FF	2.55E-05
Holcomb	SGU1	KS	Conventional Boiler	Wall firing - opposed firing	1	387	8.76	Subbituminous	DFGD, FF	2.60E-05
Roanoke Valley II	Boiler 2	NC	Conventional Boiler	Wall firing - front firing	1	50	11.20	Bituminous	SNCR, DFGD, FF	3.22E-05
Indiantown Cogeneration L.P.	001	FL	Conventional Boiler	Wall firing - opposed firing	1	361	9.48	Bituminous	SCR, DFGD, FF	3.58E-05
Rawhide	Rawhide101	CO	Conventional Boiler	Tangential firing	1	305	9.18	Subbituminous	DFGD, FF	3.61E-05
Walter Scott Jr. Energy Center	4	IA	Conventional Boiler	Wall firing - unspecified	1	850	9.03	Subbituminous	SCR, ACI, DFGD, FF	3.80E-05
Spruance Genco, LLC	GEN4	VA	Conventional Boiler	Stoker - underfeed	2	57	13.07	Bituminous	DFGD, FF	3.84E-05
Chambers Cogeneration LP	Boil 1	NJ	Conventional Boiler	Wall firing - front firing	1	285	4.87	Bituminous	SCR, DFGD, FF	4.24E-05
Navajo Generating Station	001	AZ	Conventional Boiler	Tangential firing	1	812	9.17	Bituminous	ESP, WFGD	5.00E-05
Chambers Cogeneration LP	Boil 2	NJ	Conventional Boiler	Wall firing - front firing	1	285	4.87	Bituminous	SCR, DFGD, FF	5.60E-05
Colstrip	Unit3	MT	Conventional Boiler	Tangential firing	1	805	9.41	Subbituminous	ACI, WFGD, Venturi	6.21E-05
Navajo Generating Station	002	AZ	Conventional Boiler	Tangential firing	1	812	9.17	Bituminous	ESP, WFGD	6.67E-05
Cross	C3	SC	Conventional Boiler	Tangential firing	1	625	9.69	Bituminous	SCR, ESP, WFGD	6.89E-05
Hawthorn	5A	MO	Conventional Boiler	Wall firing - opposed firing	1	594	11.11	Subbituminous, Bituminous	SCR, DFGD, FF	7.21E-05
Roanoke Valley I	Boiler 1	NC	Conventional Boiler	Wall firing - front firing	1	182	9.34	Bituminous	DFGD, FF	7.32E-05
H L Spurlock Station	Unit 03	KY	Fluidized bed firing	Fluidized bed firing	1	300	8.33	Bituminous	FBC, SNCR, DFGD, FF	7.33E-05
Hopewell	1 & 2	VA	Conventional Boiler	Stoker - spreader	2	136	6.29	Bituminous	SNCR, MC, DFGD, FF	7.34E-05
J K Spruce	1	TX	Conventional Boiler	Tangential firing	1	580	10.97	Bituminous	FF, WFGD	7.62E-05
Elm Road Generating Station	ERGS-B1	WI	Conventional Boiler	Wall firing - unspecified	1	677	9.62	Bituminous	SCR, FF; WFGD, WESP	7.64E-05
Weston	W4	WI	Conventional Boiler	Wall firing - opposed firing	1	575	9.00	Subbituminous	SCR, ACI, DFGD, FF	7.67E-05
Southampton Power Station	Unit 1 & 2	VA	Conventional Boiler	Stoker - spreader	2	136	6.54	Bituminous	MC, DFGD, FF	7.76E-05
Hammond	Unit 2	GA	Conventional Boiler	Wall firing - front firing	1	115	9.90	Bituminous	ESP, WFGD	7.88E-05
Hammond	Unit 3	GA	Conventional Boiler	Wall firing - front firing	1	115	9.93	Bituminous	ESP, WFGD	7.88E-05
Hammond	Unit 1	GA	Conventional Boiler	Wall firing - front firing	1	115	10.08	Bituminous	ESP, WFGD	7.88E-05
Hammond	Unit 4	GA	Conventional Boiler	Wall firing - front firing	1	520	10.50	Bituminous	SCR, ESP, WFGD	7.88E-05
Cholla	003	AZ	Conventional Boiler	Tangential firing	1	305	9.60	Bituminous	FF, WFGD	8.03E-05
Cholla	004	AZ	Conventional Boiler	Tangential firing	1	425	10.04	Bituminous	FF, WFGD	8.52E-05
Navajo Generating Station	003	AZ	Conventional Boiler	Tangential firing	1	812	9.17	Bituminous	ESP, WFGD	9.38E-05
Pleasant Prairie	PPPPB2	WI	Conventional Boiler	Wall firing - opposed firing	2	1298	9.94	Subbituminous	SCR, ESP, WFGD	9.44E-05
AES Puerto Rico Cogeneration Facility	Unit_2	PR	Fluidized bed firing	Fluidized bed firing	1	255	9.65	Bituminous	FBC, SCR, DFGD, ESP	9.60E-05
San Juan	Unit 3	NM	Conventional Boiler	Wall firing - opposed firing	1	544	10.58	Subbituminous	ACI, FF, WFGD	9.60E-05
Pleasant Prairie	PPPPB1	WI	Conventional Boiler	Wall firing - opposed firing	2	1298	9.94	Subbituminous	SCR, ESP, WFGD	9.66E-05
Dallman	34	IL	Conventional Boiler	Wall firing - opposed firing	1	229	8.39	Bituminous	SCR, FF, WFGD, WESP	9.70E-05
AES Puerto Rico Cogeneration Facility	Unit_1	PR	Fluidized bed firing	Fluidized bed firing	1	255	9.65	Bituminous	FBC, SNCR, DFGD, ESP	1.02E-04
Walter Scott Jr. Energy Center	3	IA	Conventional Boiler	Wall firing - unspecified	1	765	10.07	Subbituminous	DFGD, FF	1.10E-04
Hamilton	Unit 9	OH	Conventional Boiler	Tangential firing	1	51	14.41	Bituminous	ESP, DFGD, FF	1.10E-04
San Juan	Unit 1	NM	Conventional Boiler	Wall firing - front firing	1	370	10.02	Subbituminous	ACI, FF, WFGD	1.11E-04
San Juan	Unit 4	NM	Conventional Boiler	Wall firing - opposed firing	1	544	10.38	Subbituminous	ACI, FF, WFGD	1.18E-04
H L Spurlock Station	Unit 04	KY	Fluidized bed firing	Fluidized bed firing	1	300	9.33	Bituminous	FBC, SNCR, DFGD, FF	1.18E-04
Bowen	Unit 4	GA	Conventional Boiler	Tangential firing	1	933	9.53	Bituminous	SCR, ESP, WFGD	1.19E-04
Oak Grove	OG1	TX	Conventional Boiler	Tangential firing	1	817	10.98	Lignite	SCR, ACI, FF, WFGD	1.20E-04
San Juan	Unit 2	NM	Conventional Boiler	Wall firing - front firing	1	370	9.97	Subbituminous	ACI, FF, WFGD	1.24E-04
Hatfield's Ferry Power Station	001	PA	Conventional Boiler	Wall firing - opposed firing	1	590	9.66	Bituminous	ESP, WFGD	1.31E-04
Hayden	Unit 2	CO	Conventional Boiler	Tangential firing	1	285	9.52	Bituminous	DFGD, FF	1.43E-04

Source: EPA's ICR Database

HCl Floor (Continued)

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	HCl Emissions in lb/MMBtu
Cardinal	CD-U1	OH	Conventional Boiler	Wall firing - opposed firing	1	615	8.57	Bituminous	SCR, DSI, ESP, WFGD	1.43E-04
Hardin Generator Project	PC1	MT	Conventional Boiler	Wall firing - unspecified	1	119	10.96	Bituminous	SCR, ACI, DFGD, FF	1.46E-04
Neil Simpson II	NS2Cfg	WY	Conventional Boiler	Wall firing - front firing	1	88	12.50	Subbituminous	DFGD, ESP	1.47E-04
Wygen 1	WYG1Cfg	WY	Conventional Boiler	Wall firing - front firing	1	91	11.57	Subbituminous	SCR, DFGD, FF	1.54E-04
Healy	1	AK	Conventional Boiler	Wall firing - front firing	1	25	13.88	Subbituminous	FF	1.54E-04
Bowen	Unit 2	GA	Conventional Boiler	Tangential firing	1	755	10.84	Bituminous	SCR, ESP, WFGD	1.56E-04
Whelan Energy Center Unit 1 (WEC1)	1	NE	Conventional Boiler	Tangential firing	1	84	10.11	Subbituminous	ESP	1.62E-04
AES Petersburg	2ss	IN	Conventional Boiler	Tangential firing	1	445	9.31	Bituminous	SCR, ESP, WFGD	1.62E-04
Yates	Y1BR	GA	Conventional Boiler	Tangential firing	1	107	10.23	Bituminous	ESP, WFGD	1.63E-04
Conesville	CV-4	OH	Conventional Boiler	Tangential firing	1	842	9.46	Bituminous	SCR, ESP, DSI, WFGD	1.63E-04
AES Petersburg	1s	IN	Conventional Boiler	Tangential firing	1	255	8.63	Bituminous	ESP, WFGD	1.76E-04
Ghent	GH1	KY	Conventional Boiler	Tangential firing	1	520	12.09	Bituminous	SCR, DSI, ESP, WFGD	1.80E-04
John E. Amos	AM-2	WV	Conventional Boiler	Wall firing - opposed firing	1	816	8.60	Bituminous	SCR, ESP, WFGD	1.83E-04
Cardinal	CD-U2	OH	Conventional Boiler	Wall firing - opposed firing	1	615	8.57	Bituminous	SCR, DSI, ESP, WFGD	1.85E-04
Cherokee	Unit 2	CO	Conventional Boiler	Vertical firing	1	114	12.21	Bituminous	DFGD, FF	1.86E-04
Louisa	101	IA	Conventional Boiler	Wall firing - unspecified	1	805	10.71	Subbituminous	DFGD, FF	1.91E-04
Welsh	WE-1	TX	Conventional Boiler	Wall firing - opposed firing	1	558	9.24	Subbituminous	ESP	1.94E-04
Valmont	Unit 5	CO	Conventional Boiler	Tangential firing	1	196	9.41	Bituminous	DFGD, FF	2.11E-04
Mountaineer	Mt-1	WV	Conventional Boiler	Wall firing - opposed firing	1	1320	9.06	Bituminous	SCR, DSI, ESP, WFGD	2.14E-04
Arapahoe	Unit 3	CO	Conventional Boiler	Vertical firing	1	48	15.73	Subbituminous	DSI, FF	2.18E-04
Hayden	Unit 1	CO	Conventional Boiler	Wall firing - front firing	1	202	9.72	Bituminous	DFGD, FF	2.18E-04
Wansley	Unit 2	GA	Conventional Boiler	Tangential firing	1	920	9.30	Bituminous	SCR, ESP, WFGD	2.21E-04
R D Green	2	KY	Conventional Boiler	Wall firing - opposed firing	1	239	11.41	Bituminous, Petroleum Coke	ESP, WFGD	2.23E-04
Cherokee	Unit 1	CO	Conventional Boiler	Vertical firing	1	117	11.90	Bituminous	DSI, FF	2.25E-04
Cross	C4	SC	Conventional Boiler	Tangential firing	1	625	10.88	Bituminous	SCR, ESP, WFGD	2.29E-04
Cherokee	Unit 4	CO	Conventional Boiler	Tangential firing	1	383	9.19	Bituminous	DFGD, FF	2.37E-04
Cross	C1	SC	Conventional Boiler	Wall firing - opposed firing	1	610	10.66	Bituminous	SCR, ESP, WFGD	2.44E-04
Bowen	Unit 3	GA	Conventional Boiler	Tangential firing	1	933	7.81	Bituminous	SCR, ESP, WFGD	2.50E-04
HMP&L Station Two Henderson	1	KY	Conventional Boiler	Wall firing - rear firing	1	166	10.83	Bituminous	SCR, ESP, WFGD	2.52E-04
Gibson	4	IN	Conventional Boiler	Wall firing - opposed firing	1	661	9.48	Bituminous	SCR, DSI, ESP, WFGD	2.61E-04
Crystal River Power Plant	CryR_Cfg_5c	FL	Conventional Boiler	Wall firing - opposed firing	1	767	9.68	Bituminous	SCR, ESP, WFGD	2.74E-04
Nebraska City	NC2	NE	Conventional Boiler	Wall firing - front firing	1	682	10.15	Bituminous	SCR, ACI, DFGD, FF	2.76E-04
Marshall	U4	NC	Conventional Boiler	Tangential firing	1	700	8.61	Bituminous	SNCR, ESP, WFGD	2.83E-04
Mt. Storm	Unit 3	WV	Conventional Boiler	Tangential firing	1	560	10.58	Bituminous	SCR, ESP, WFGD	2.85E-04
Marshall	U12007	NC	Conventional Boiler	Tangential firing	1	400	9.15	Bituminous	SNCR, ESP, WFGD	2.86E-04
Marshall	U22007	NC	Conventional Boiler	Tangential firing	1	400	9.16	Bituminous	SNCR, ESP, WFGD	2.86E-04
Conemaugh	CON-1	PA	Conventional Boiler	Tangential firing	1	936	9.60	Bituminous	ESP, WFGD	2.88E-04
Montrose	2	MO	Conventional Boiler	Tangential firing	1	188	11.33	Subbituminous	DSI, ESP	3.00E-04
Montrose	1	MO	Conventional Boiler	Tangential firing	1	188	11.38	Subbituminous	DSI, ESP	3.00E-04
Montrose	3	MO	Conventional Boiler	Tangential firing	1	188	11.97	Subbituminous	DSI, ESP	3.00E-04

Source: EPA's ICR Database

HCl Floor (Continued)

Plant Name	Unit ID	State	Unit Type	Boiler Type	Boilers	Capacity	Heat Rate	Fuel Type	Control Summary	HCl Emissions in lb/MMBtu
PPL Montour	U1	PA	Conventional Boiler	Tangential firing	1	797	9.08	Bituminous	ESP, SCR, WFGD	3.02E-04
HMP&L Station Two Henderson	2	KY	Conventional Boiler	Wall firing - rear firing	1	173	10.78	Bituminous	SCR, ESP, WFGD	3.05E-04
Cherokee	Unit 3	CO	Conventional Boiler	Wall firing - front firing	1	165	11.38	Bituminous	DFGD, FF	3.05E-04
Springerville	3	AZ	Conventional Boiler	Wall firing - opposed firing	1	450	9.33	Subbituminous	SCR, DFGD, FF	3.06E-04
Wansley	Unit 1	GA	Conventional Boiler	Tangential firing	1	920	9.18	Bituminous	SCR, ESP, WFGD	3.11E-04
John E. Amos	AM-3	WV	Conventional Boiler	Wall firing - opposed firing	1	1300	9.18	Bituminous	SCR, ESP, WFGD	3.13E-04
Cogentrix Virginia Leasing Corporation	GEN2	VA	Conventional Boiler	Stoker - underfeed	3	58	10.43	Bituminous	DFGD, FF	3.15E-04
Cumberland	1	TN	Conventional Boiler	Wall firing - opposed firing	1	1300	10.87	Bituminous	SCR, DSI, ESP, WFGD	3.17E-04
Marshall	U3	NC	Conventional Boiler	Tangential firing	1	700	8.72	Bituminous	SCR, ESP, WFGD	3.26E-04
Conemaugh	CON-2	PA	Conventional Boiler	Tangential firing	1	936	9.60	Bituminous	ESP, WFGD	3.33E-04
Cumberland	2	TN	Conventional Boiler	Wall firing - opposed firing	1	1300	10.87	Bituminous	SCR, DSI, ESP, WFGD	3.35E-04
Clover	Unit 2	VA	Conventional Boiler	Tangential firing	1	434	11.62	Bituminous	SNCR, FF, WFGD	3.38E-04
PPL Montour	U2	PA	Conventional Boiler	Tangential firing	1	792	9.14	Bituminous	ESP, SCR, WFGD	3.57E-04
AES Cayuga, LLC	Unit_1	NY	Conventional Boiler	Tangential firing	1	164	8.91	Bituminous	SCR, ESP, WFGD	3.59E-04
Red Hills Generating Facility	002	MS	Fluidized bed firing	Fluidized bed firing	1	250	9.53	Lignite	FBC, FF	3.67E-04
Red Hills Generating Facility	001	MS	Fluidized bed firing	Fluidized bed firing	1	250	9.60	Lignite	FBC, FF	3.67E-04
Clover	Unit 1	VA	Conventional Boiler	Tangential firing	1	431	11.42	Bituminous	FF, WFGD	3.73E-04
Quindaro	Unit 1	KS	Conventional Boiler	Cyclone firing	1	77	10.16	Subbituminous	ESP	3.80E-04
Wygen 2	WYG2Cfg	WY	Conventional Boiler	Wall firing - front firing	1	96	13.54	Subbituminous	SCR, DFGD, FF	3.92E-04
PSEG Hudson Generating Station	HUDU2E2PT2OS 1-Coal	NJ	Conventional Boiler	Wall firing - opposed firing	1	660	10.00	Subbituminous	SNCR, ESP	3.94E-04
PPL Brunner Island	U2	PA	Conventional Boiler	Tangential firing	1	393	9.64	Bituminous	ESP, WFGD	3.98E-04
PPL Brunner Island	U1	PA	Conventional Boiler	Tangential firing	1	330	10.14	Bituminous	FF, WFGD	3.98E-04
BL England	2 Coal w or w/o TDF	NJ	Conventional Boiler	Cyclone firing	1	167	9.56	Bituminous	SNCR, ACI, ESP, WFGD	4.05E-04
Homer City Station	HC3CONFIG	PA	Conventional Boiler	Wall firing - opposed firing	1	680	9.08	Bituminous	SCR, ESP, WFGD	4.06E-04
Nearman Creek	N1	KS	Conventional Boiler	Wall firing - front firing	1	257	9.45	Subbituminous	ESP	4.10E-04
Laramie River Station	3	WY	Conventional Boiler	Wall firing - opposed firing	1	610	10.82	Subbituminous	DFGD, ESP	4.11E-04
Mt. Storm	Unit 1&2	WV	Conventional Boiler	Tangential firing	2	1109	11.91	Bituminous	SCR, ESP, WFGD	4.20E-04
Reid Gardner	3	NV	Conventional Boiler	Wall firing - front firing	1	111	11.14	Bituminous	FF, WFGD	4.52E-04
AES Cayuga, LLC	Unit_2	NY	Conventional Boiler	Tangential firing	1	168	8.63	Bituminous	ESP, WFGD	4.66E-04
Mecklenburg Power Station	Unit 1 & 2	VA	Conventional Boiler	Wall firing - front firing	2	152	12.07	Bituminous	DFGD, FF	4.86E-04
Newton	002	IL	Conventional Boiler	Tangential firing	1	620	8.87	Subbituminous	ACI, ESP	4.87E-04
Prairie Creek	Unit 2	IA	Conventional Boiler	Stoker - overfeed	4	221	12.33	Subbituminous	ESP	5.00E-04
Duck Creek	001	IL	Conventional Boiler	Wall firing - unspecified	1	400	11.25	Subbituminous	SCR, ESP, WFGD	5.01E-04
Boswell Energy Center	BEC3	MN	Conventional Boiler	Tangential firing	1	371	11.08	Subbituminous	SCR, ESP, ACI, FF	5.13E-04
Ghent	GH3	KY	Conventional Boiler	Wall firing - opposed firing	1	525	11.18	Bituminous	DSI, ESP, SCR, WFGD	5.27E-04
East Bend Station	2	KY	Conventional Boiler	Wall firing - front firing	1	651	9.70	Bituminous	DSI, ESP, SCR, WFGD	5.28E-04
Joliet 9	JOL5 CONFIG	IL	Conventional Boiler	Cyclone firing	1	326	10.96	Subbituminous	ACI, ESP	5.41E-04
Elrama Power Plant	ELR4-2	PA	Conventional Boiler	Wall firing - front firing	1	185	10.38	Bituminous	SNCR, MC, ESP, WFGD	5.53E-04
Elrama Power Plant	ELR3-2	PA	Conventional Boiler	Vertical firing	1	125	10.42	Bituminous	SNCR, MC, ESP, WFGD	5.53E-04
Elrama Power Plant	ELR1-2	PA	Conventional Boiler	Vertical firing	1	100	12.54	Bituminous	SNCR, MC, ESP, WFGD	5.53E-04

Source: EPA's ICR Database

Appendix 2: List of EPA's Projected Coal Retirements by Unit

Projected EPA Coal Retirements by Unit

Plant Name	Unit	State	Capacity (MW)	Coal Type	Retirement Category
Arapahoe	3	Colorado	47	Subbituminous	Planned
Arapahoe	4	Colorado	121	Subbituminous	Planned
Avon Lake	10	Ohio	93	Bituminous	Incremental
Blount Street	5	Wisconsin	22	Bituminous	Planned
Blount Street	8	Wisconsin	49	Bituminous	Incremental
Blount Street	9	Wisconsin	48	Bituminous	Incremental
Blue Valley	3	Missouri	51	Bituminous	Incremental
BP Wilmington Calciner	GEN1	California	29	Waste coal	Incremental
Brayton Point	3	Massachusetts	612	Bituminous	Incremental
Bremo Bluff	3	Virginia	71	Bituminous	Incremental
Bremo Bluff	4	Virginia	156	Bituminous	Incremental
Buck	5	North Carolina	38	Bituminous	Incremental
Buck	6	North Carolina	38	Bituminous	Incremental
Buck	7	North Carolina	38	Bituminous	Incremental
Canadys Steam	CAN1	South Carolina	105	Bituminous	Incremental
Cape Fear	5	North Carolina	144	Bituminous	Incremental
Cape Fear	6	North Carolina	172	Bituminous	Incremental
Carbon	1	Utah	67	Bituminous	Incremental
Chamois	2	Missouri	49	Bituminous	Incremental
Cherokee	2	Colorado	120	Bituminous	Planned
Cherokee	1	Colorado	115	Bituminous	Planned
Chesapeake	2	Virginia	111	Bituminous	Incremental
Cliffside	1	North Carolina	39	Bituminous	Planned
Cliffside	2	North Carolina	39	Bituminous	Planned
Cliffside	3	North Carolina	62	Bituminous	Planned
Cliffside	4	North Carolina	62	Bituminous	Planned
Colbert	1	Alabama	176	Bituminous	Incremental
Colbert	2	Alabama	176	Bituminous	Incremental
Colbert	3	Alabama	176	Bituminous	Incremental
Colbert	4	Alabama	172	Bituminous	Incremental
Colstrip Energy LP	BLR1	Montana	35	Waste coal	Incremental
Cromby Generating Station	1	Pennsylvania	135	Bituminous	Planned
D B Wilson	W1	Kentucky	420	Bituminous	Incremental
Dale	1	Kentucky	27	Bituminous	Incremental
Dale	2	Kentucky	27	Bituminous	Incremental
Dale	3	Kentucky	75	Bituminous	Incremental
Dale	4	Kentucky	75	Bituminous	Incremental
Dallman	31	Illinois	86	Bituminous	Incremental
Dallman	32	Illinois	87	Bituminous	Incremental

Source: EPA's IPM Retirement Database and FBR Research

EPA Retirements (Continued)

Plant Name	Unit	State	Capacity (MW)	Coal Type	Retirement Category
Dan River	1	North Carolina	67	Bituminous	Planned
Dan River	2	North Carolina	67	Bituminous	Planned
Dan River	3	North Carolina	142	Bituminous	Planned
Deepw ater	8	New Jersey	80	Bituminous	Incremental
Dubuque	1	Iow a	35	Subbituminous	Incremental
Dubuque	5	Iow a	30	Subbituminous	Incremental
Eagle Valley	3	Indiana	43	Bituminous	Incremental
Eagle Valley	4	Indiana	56	Bituminous	Incremental
Earl F Wisdom	1	Iow a	38	Bituminous	Incremental
Eastlake	3	Ohio	132	Subbituminous	Incremental
Eckert Station	1	Michigan	40	Subbituminous	Incremental
Eckert Station	2	Michigan	42	Subbituminous	Incremental
Eckert Station	3	Michigan	41	Subbituminous	Incremental
Eckert Station	4	Michigan	69	Subbituminous	Incremental
Eckert Station	5	Michigan	69	Subbituminous	Incremental
Eckert Station	6	Michigan	67	Subbituminous	Incremental
Eddystone Generating Station	2	Pennsylvania	309	Bituminous	Planned
Eddystone Generating Station	1	Pennsylvania	648	Bituminous	Planned
Edw ardsport	7-1	Indiana	45	Bituminous	Planned
Edw ardsport	8-1	Indiana	75	Bituminous	Planned
Endicott Station	1	Michigan	55	Bituminous	Incremental
ERCT_TX_Coal steam	1	Texas	300	Subbituminous	Incremental
G F Weaton Pow er Station	BLR1	Pennsylvania	56	Subbituminous	Incremental
G F Weaton Pow er Station	BLR2	Pennsylvania	56	Subbituminous	Incremental
Glen Lyn	51	Virginia	45	Bituminous	Incremental
Glen Lyn	52	Virginia	45	Bituminous	Incremental
How ard Dow n	10	New Jersey	23	Bituminous	Incremental
Hutsonville	05	Illinois	76	Subbituminous	Incremental
Hutsonville	06	Illinois	77	Subbituminous	Incremental
Indian River Generating Station	3	Delaw are	153	Bituminous	Planned
Indian River Generating Station	1	Delaw are	90	Bituminous	Planned
Indian River Generating Station	2	Delaw are	165	Bituminous	Planned
Jack McDonough	MB1	Georgia	258	Bituminous	Planned
Jack McDonough	MB2	Georgia	259	Bituminous	Planned
James De Young	5	Michigan	27	Bituminous	Incremental
James River Pow er Station	3	Missouri	41	Subbituminous	Incremental
James River Pow er Station	4	Missouri	56	Subbituminous	Incremental
John Sevier	1	Tennessee	176	Bituminous	Planned
John Sevier	2	Tennessee	176	Bituminous	Planned
John Sevier	3	Tennessee	176	Bituminous	Incremental
John Sevier	4	Tennessee	176	Bituminous	Incremental

Source: EPA's IPM Retirement Database and FBR Research

EPA Retirements (Continued)

Plant Name	Unit	State	Capacity (MW)	Coal Type	Retirement Category
Johnsonville	1	Tennessee	106	Subbituminous	Incremental
Johnsonville	10	Tennessee	141	Subbituminous	Incremental
Johnsonville	2	Tennessee	106	Subbituminous	Incremental
Johnsonville	3	Tennessee	106	Subbituminous	Incremental
Johnsonville	4	Tennessee	106	Subbituminous	Incremental
Johnsonville	5	Tennessee	106	Subbituminous	Incremental
Johnsonville	6	Tennessee	106	Subbituminous	Incremental
Johnsonville	7	Tennessee	141	Subbituminous	Incremental
Johnsonville	8	Tennessee	141	Subbituminous	Incremental
Johnsonville	9	Tennessee	141	Subbituminous	Incremental
Kraft	1	Georgia	48	Bituminous	Incremental
KUCC	1	Utah	30	Bituminous	Incremental
KUCC	2	Utah	30	Bituminous	Incremental
KUCC	3	Utah	30	Bituminous	Incremental
L V Sutton	1	North Carolina	93	Bituminous	Planned
L V Sutton	2	North Carolina	102	Bituminous	Planned
L V Sutton	3	North Carolina	403	Bituminous	Planned
Lansing	2	Iowa	11	Subbituminous	Planned
Lansing	3	Iowa	37	Subbituminous	Planned
Lansing	1	Iowa	292	Subbituminous	Planned
Lawrence Energy Center	3	Kansas	48	Subbituminous	Incremental
Lee	1	North Carolina	74	Bituminous	Planned
Lee	2	North Carolina	77	Bituminous	Planned
Lee	3	North Carolina	248	Bituminous	Planned
Marion	4	Illinois	170	Waste coal	Incremental
Marshall	4	Missouri	5	Bituminous	Incremental
Marshall	5	Missouri	16	Bituminous	Incremental
Marysville	9	Michigan	42	Bituminous	Planned
Marysville	10	Michigan	42	Bituminous	Planned
Marysville	11	Michigan	42	Bituminous	Planned
Marysville	12	Michigan	42	Bituminous	Planned
Meredosia	01	Illinois	72	Subbituminous	Planned
Meredosia	02	Illinois	72	Subbituminous	Planned
Meredosia	03	Illinois	72	Subbituminous	Planned
Meredosia	05	Illinois	203	Subbituminous	Incremental
Milton L Kapp	1	Iowa	9	Subbituminous	Planned
Missouri City	1	Missouri	19	Bituminous	Incremental
Missouri City	2	Missouri	19	Bituminous	Incremental
Mohave	1	Nevada	790	Subbituminous	Planned
Mohave	2	Nevada	790	Subbituminous	Planned

Source: EPA's IPM Retirement Database and FBR Research

EPA Retirements (Continued)

Plant Name	Unit	State	Capacity (MW)	Coal Type	Retirement Category
Mt Poso Cogeneration	BL01	California	52	Bituminous	Planned
Muscatine Plant #1	8	Iowa	35	Subbituminous	Incremental
Muskingum River	1	Ohio	190	Bituminous	Incremental
Muskingum River	2	Ohio	190	Bituminous	Incremental
Navajo	1	Arizona	750	Bituminous	Incremental
Navajo	2	Arizona	750	Bituminous	Incremental
Navajo	3	Arizona	750	Bituminous	Incremental
New Castle	3	Pennsylvania	95	Bituminous	Incremental
New Castle	5	Pennsylvania	138	Bituminous	Incremental
Niles	2	Ohio	111	Bituminous	Incremental
Northside Generating Station	1	Florida	275	Subbituminous	Incremental
Northside Generating Station	2	Florida	275	Subbituminous	Incremental
Philip Sporn	51	West Virginia	450	Bituminous	Planned
Picway	9	Ohio	95	Bituminous	Incremental
Potomac River	1	Virginia	88	Bituminous	Incremental
Potomac River	2	Virginia	88	Bituminous	Incremental
Prairie Creek	2	Iowa	10	Subbituminous	Planned
Quindaro	1	Kansas	72	Subbituminous	Incremental
Quindaro	2	Kansas	110	Subbituminous	Incremental
R E Burger	5	Ohio	47	Bituminous	Incremental
R E Burger	6	Ohio	47	Bituminous	Incremental
R Gallagher	1	Indiana	140	Bituminous	Incremental
R Gallagher	3	Indiana	140	Bituminous	Incremental
Richard Gorsuch	1	Ohio	50	Bituminous	Planned
Richard Gorsuch	2	Ohio	50	Bituminous	Planned
Richard Gorsuch	3	Ohio	50	Bituminous	Planned
Richard Gorsuch	4	Ohio	50	Bituminous	Planned
Riverbend	7	North Carolina	94	Bituminous	Incremental
Riverbend	8	North Carolina	94	Bituminous	Incremental
Riverton	39	Kansas	38	Subbituminous	Incremental
Riverton	40	Kansas	54	Subbituminous	Incremental
Rivesville	7	West Virginia	46	Bituminous	Incremental
Rivesville	8	West Virginia	91	Bituminous	Incremental
Robert A Reid	R1	Kentucky	65	Bituminous	Incremental
Rodemacher	3A	Louisiana	330	Subbituminous	Incremental
Rumford Cogeneration	6	Maine	42	Bituminous	Incremental
Rumford Cogeneration	7	Maine	42	Bituminous	Incremental
S A Carlson	10	New York	15	Bituminous	Incremental
S A Carlson	12	New York	15	Bituminous	Incremental
S A Carlson	9	New York	15	Bituminous	Incremental
Salem Harbor	1	Massachusetts	82	Bituminous	Incremental
Salem Harbor	2	Massachusetts	80	Bituminous	Incremental
Salem Harbor	3	Massachusetts	149	Bituminous	Incremental

Source: EPA's IPM Retirement Database and FBR Research

EPA Retirements (Continued)

Plant Name	Unit	State	Capacity (MW)	Coal Type	Retirement Category
San Miguel	SM-1	Texas	391	Lignite	Incremental
Sandow	4	Texas	544	Lignite	Incremental
Schiller	4	New Hampshire	48	Bituminous	Incremental
Scholz	1	Florida	49	Bituminous	Incremental
Scholz	2	Florida	49	Bituminous	Incremental
Shaw ville	1	Pennsylvania	122	Bituminous	Incremental
Sibley	1	Missouri	54	Subbituminous	Incremental
Sibley	2	Missouri	54	Subbituminous	Incremental
Sixth Street	5	Iow a	14	Subbituminous	Planned
Sixth Street	2	Iow a	14	Subbituminous	Planned
Sixth Street	3	Iow a	14	Subbituminous	Planned
Sixth Street	4	Iow a	14	Subbituminous	Planned
South Oak Creek	5	Wisconsin	261	Subbituminous	Incremental
South Oak Creek	6	Wisconsin	264	Subbituminous	Incremental
Sunbury Generation LP	3	Pennsylvania	94	Bituminous	Incremental
Sunbury Generation LP	4	Pennsylvania	128	Bituminous	Incremental
Sunnyside Cogen Associates	1	Utah	51	Waste Coal	Incremental
Sutherland	2	Iow a	31	Subbituminous	Planned
Tanners Creek	U1	Indiana	145	Bituminous	Incremental
Tecumseh Energy Center	10	Kansas	129	Subbituminous	Incremental
Tecumseh Energy Center	9	Kansas	74	Subbituminous	Incremental
Trenton Channel	16	Michigan	53	Subbituminous	Incremental
Trenton Channel	17	Michigan	53	Subbituminous	Incremental
Trenton Channel	18	Michigan	53	Subbituminous	Incremental
Tyrone	5	Kentucky	71	Bituminous	Incremental
Valley	1	Wisconsin	70	Bituminous	Incremental
Valley	2	Wisconsin	70	Bituminous	Incremental
Valley	3	Wisconsin	70	Bituminous	Incremental
Valley	4	Wisconsin	70	Bituminous	Incremental
W H Weatherspoon	1	North Carolina	48	Bituminous	Incremental
W H Weatherspoon	2	North Carolina	49	Bituminous	Incremental
W H Weatherspoon	3	North Carolina	76	Bituminous	Incremental
Wabash River	2	Indiana	85	Bituminous	Planned
Wabash River	3	Indiana	85	Bituminous	Planned
Wabash River	5	Indiana	95	Bituminous	Planned
Widow s Creek	1	Alabama	111	Bituminous	Planned
Widow s Creek	2	Alabama	111	Bituminous	Planned
Widow s Creek	3	Alabama	111	Bituminous	Planned
Widow s Creek	4	Alabama	111	Bituminous	Planned
Widow s Creek	5	Alabama	111	Bituminous	Planned
Widow s Creek	6	Alabama	111	Bituminous	Planned
Will County	1	Illinois	151	Subbituminous	Planned
Will County	2	Illinois	148	Subbituminous	Planned
Willow Island	1	West Virginia	54	Bituminous	Incremental
Grand Total			**24,724**		

Source: EPA's IPM Retirement Database and FBR Research

Industry Risks

Level of interest rates affects valuation. There is a strong correlation between the trading multiples of regulated electric utilities and long-term interest rates. If long-term rates were to increase sharply, we would expect the trading multiples to contract.

Capital plan execution risk. Regulated utilities may not complete their capital budgets or obtain timely recovery for them. This could have an adverse effect on earnings growth, cash flows, and valuation.

Sufficient regulatory recovery is not guaranteed. Most of the regulated utilities operate on a rate-of-return/cost-of-service basis. If adequate recovery on invested capital is not achieved in a timely fashion, earnings and cash flows could be pressured. This could lead to dilutive equity issuances.

Economic downturns reduce demand for electricity. Poor economic conditions typically result in weaker electricity sales and cash flows and affect the rate of delinquent customer accounts receivable. When industrial customers reduce production, there is a particularly large negative impact on electricity consumption.

Potentially high environmental compliance costs associated with coal or carbon. Many utilities rely heavily on coal for electricity production and could face higher environmental compliance costs for carbon emissions or coal. While these costs will likely be passed through to customers for regulated utilities, we are not certain how much would be recovered. Such costs could force electricity rates up, resulting in regulatory "pushback." Merchant utilities relying heavily on coal or natural gas could incur higher compliance costs, and not all of these costs would necessarily be recovered through market pricing dynamics.

Natural gas prices, which are volatile, can have an impact on the valuation of integrated names. Changes in the price of natural gas can affect the valuation of integrated electric utilities, both to the upside and to the downside. Such volatility appears inherent to the sector.

Increases in cost of fuel can squeeze merchant margins. Coal, uranium, and natural gas are some of the fuel resources that competitive businesses rely on. Increases in the cost of these commodities, without offsetting power price increases, can adversely affect profit margins.

*Closing price of last trading day immediately prior to the date of this publication unless otherwise indicated

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Selling Uncovered Puts--Significant risk that investors will experience losses much greater than premium income received.

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Buying Calendar Spreads (different expiration months with short expiration earlier than long). Investors may lose the entire premium paid.

Selling Call or Put Vertical Spreads (Calls--short call and long call with higher strike; Puts--short put and long put with a lower strike, same expiration month for both options.) Investors risk the loss of the difference between the strike prices, reduced by the premium received.

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HOLD [Market Perform]	45.3%	5.7%
SELL [Underperform]	6.0%	3.6%

(1) As of midnight on the business day immediately prior to the date of this publication.

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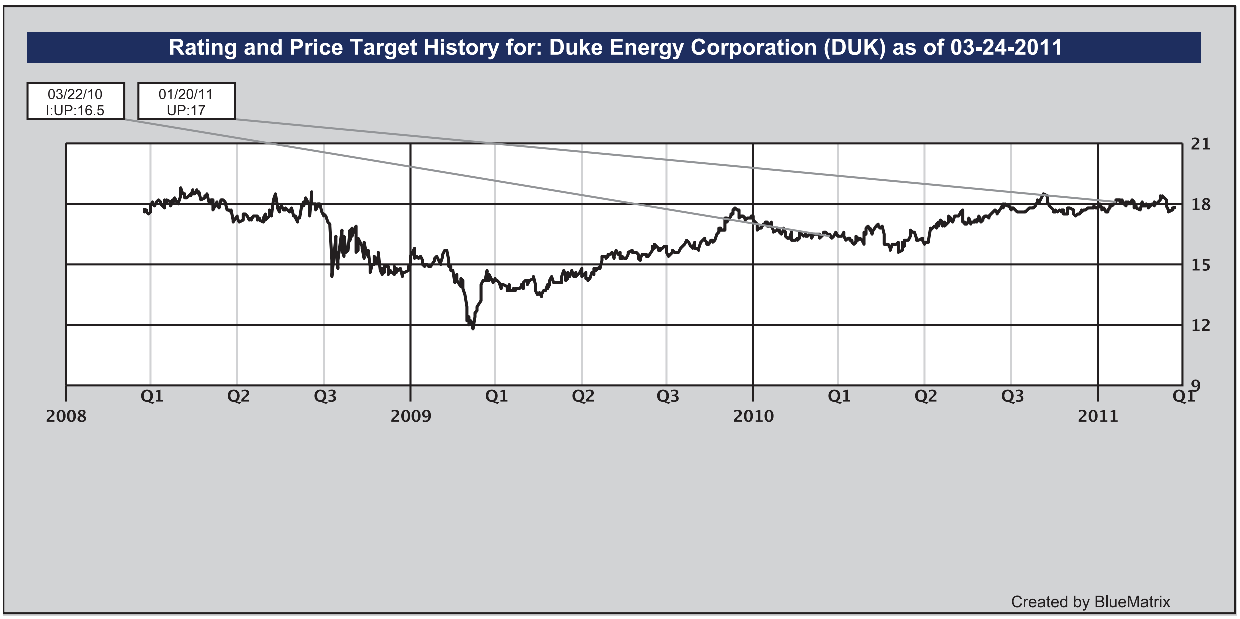

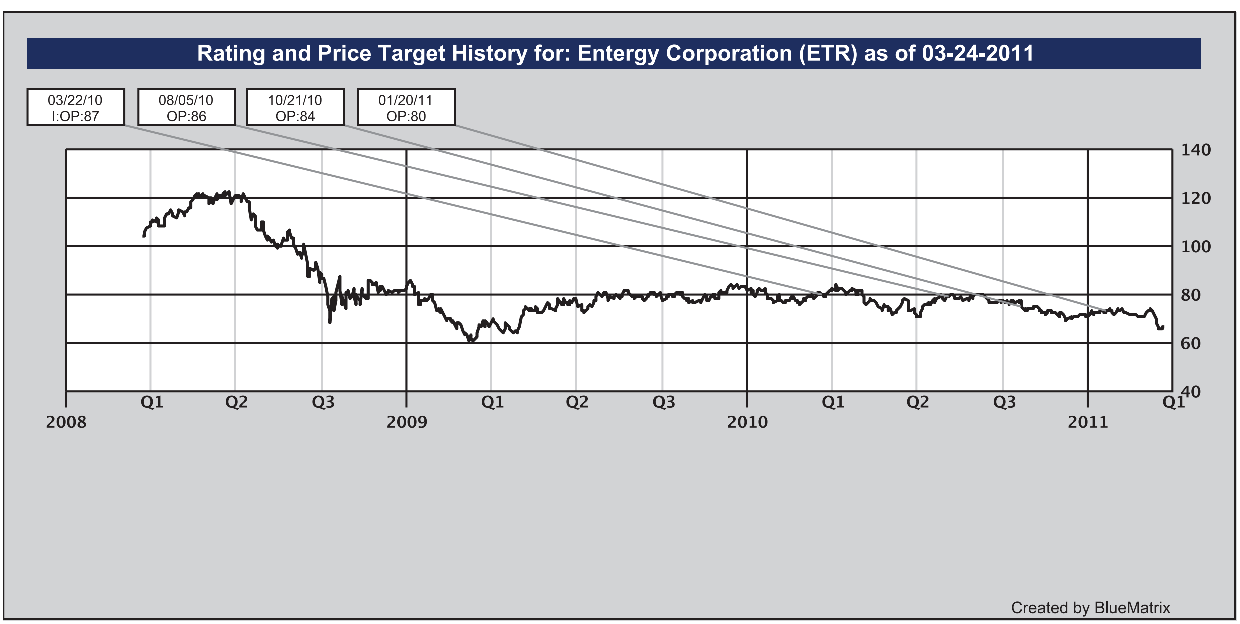

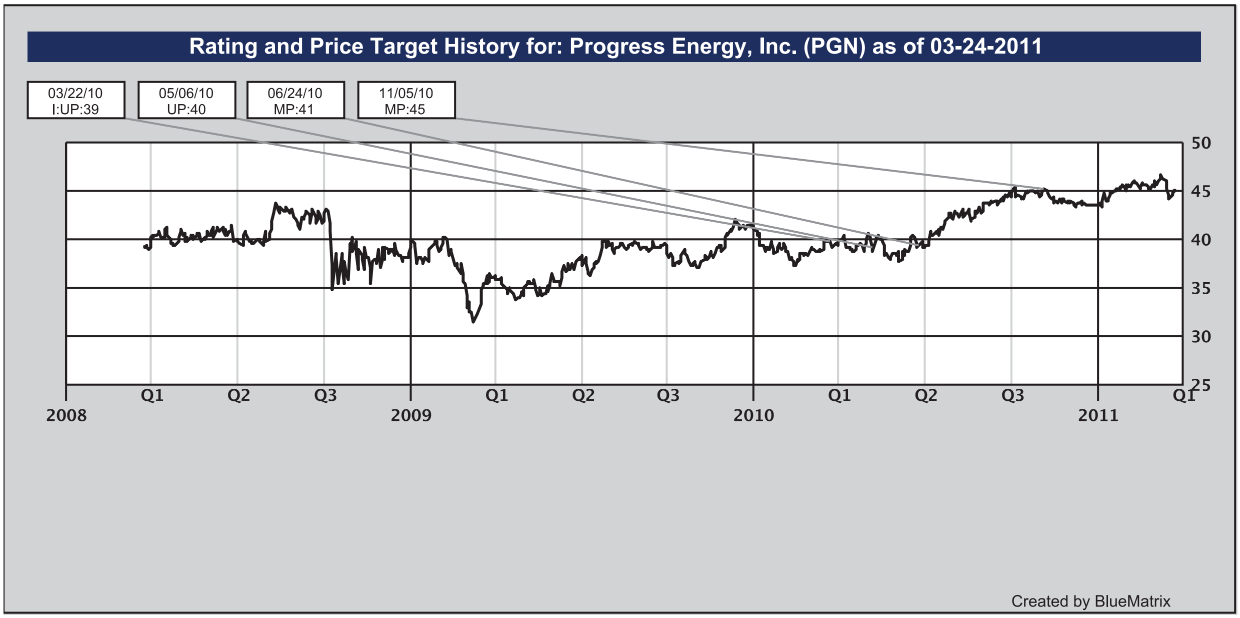

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05/06/10
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06/24/10
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11/05/10
MP:45
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45
40
35
30
25
Q1
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Q3
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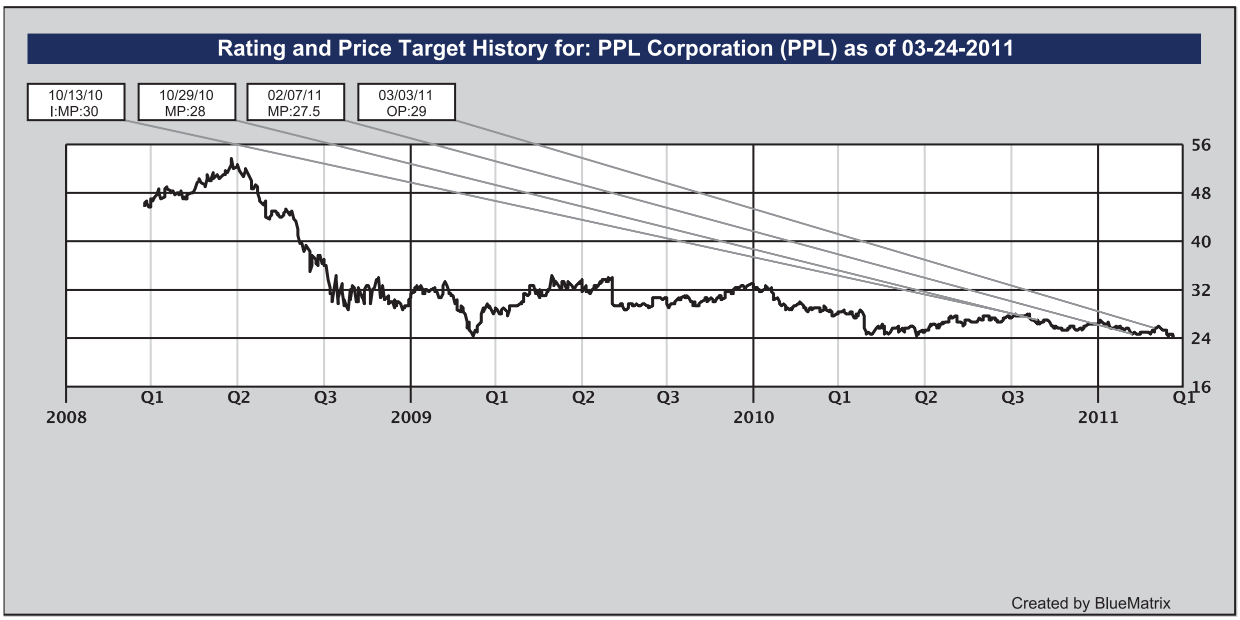

Rating and Price Target History for: PPL Corporation (PPL) as of 03-24-2011
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02/07/11
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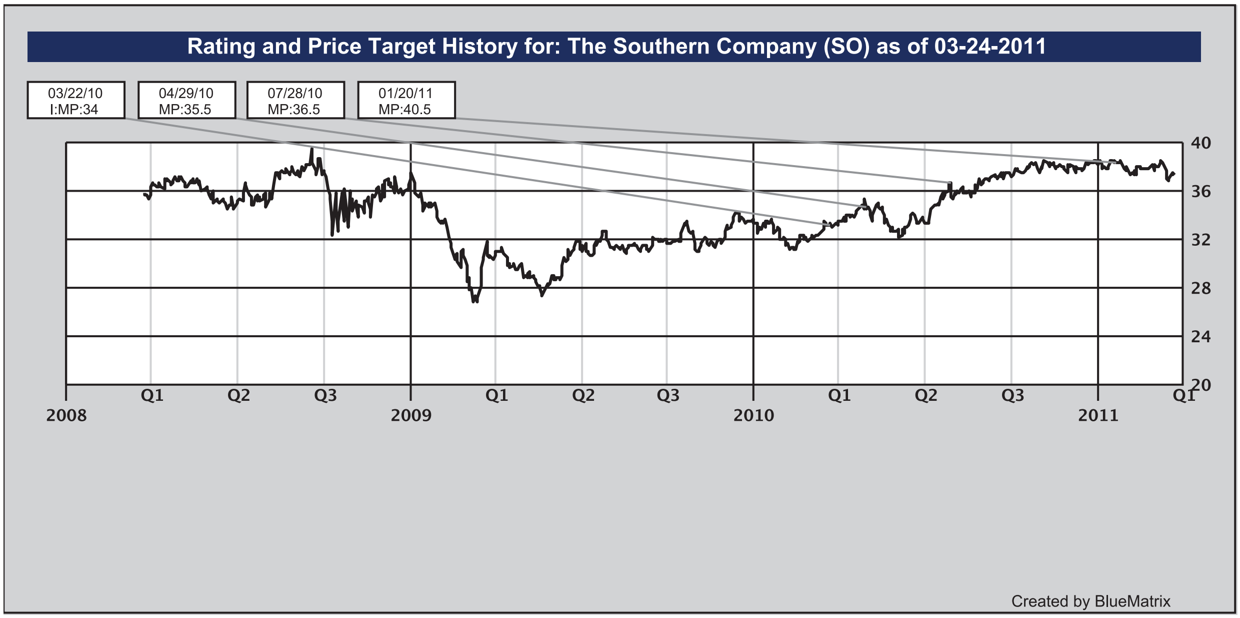
Rating and Price Target History for: The Southern Company (SO) as of 03-24-2011
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MP:40.5
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24
20
Q1
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Q3
Q1
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Q1
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2008
2009
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COAL UNIT RETIREMENTS[1]

As of December 30, 2015

- Since 2010, utilities have announced the retirement of a very large number of coal-fired electric generating units.[2] In addition to these retirements, some coal units are converting to natural gas, and a small number are converting to biomass or another fuel. Most of these retirements and conversions have been attributed to EPA policies, although other factors may play a role too.[3]

- Table 1 lists 37 states with coal retirements and conversions that have been attributed to EPA policies. These retirements and conversions total 410 units and represent nearly 67,000 megawatts (MW) of electric generating capacity. Approximately 12,000 MW (one-fifth of the total) are converting to natural gas, biomass, or another fuel. By the end of 2016, 51,481 MW will retire or convert due to EPA policies.

- Table 2 lists all announced coal retirements and conversions, regardless of cause, through 2030. (Table 2 includes the units in Table 1 plus additional retirements and conversions that have not been attributed to EPA policies.) Table 2 shows that 499 units — totaling over 81,000 MW — are slated for retirement or conversion. These units are located in 42 states and represent 26% of the U.S. coal fleet that existed in 2010. Approximately 14,000 MW (slightly less than one-fifth of the total) are converting to natural gas, biomass, or another fuel.

- By the end of 2015, approximately 50,000 MW will have retired or converted. Between 2016 and 2019, an additional 22,000 MW are expected to retire or convert.[4]

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[1] This list of retirements and conversions is based primarily on public announcements by the owners of the coal units. We also use other information sources that are highly reliable. These retirements and conversions are not based on modeling projections.
[2] In 2010, according to EIA, the U.S. coal fleet was comprised of 1,396 electric generating units at 580 power plants that represented a total electric generating capacity of more than 315,000 MW.
[3] "EPA policies" include EPA regulations, as well as settlement agreements resulting from EPA's New Source Review enforcement activities. Other factors contributing to the shutdowns in Table 1 include low natural gas prices.
[4] 4,831 MW are slated to retire or convert after 2025.

TABLE 1. Coal Units Retiring or Converting Because of EPA Policies[5]

STATE	MW CLOSING OR CONVERTING	UNITS CLOSING OR CONVERTING
1. Ohio	6,421	40
2. Pennsylvania	5,548	30
3. Alabama	5,166	26
4. Indiana	4,308	25
5. Kentucky	3,471	16
6. Georgia	3,249	15
7. Illinois	2,996	13
8. North Carolina	2,783	20
9. West Virginia	2,737	18
10. Virginia	2,354	16
11. Tennessee	2,299	15
12. Minnesota	2,014	13
13. South Carolina	1,759	14
14. Missouri	1,738	17
15. Arkansas	1,659	2
16. Florida	1,568	7
17. Iowa	1,564	28
18. Oklahoma	1,464	3
19. Massachusetts	1,408	6
20. Texas	1,399	3
21. New Mexico	1,375	5
22. Michigan	1,352	16
23. Maryland	1,319	7
24. Wisconsin	1,287	16
25. Colorado	1,172	11
26. Arizona	822	4
27. Mississippi	706	2
28. Nebraska	637	5
29. Oregon	585	1
30. Louisiana	575	1
31. New York	475	3
32. New Jersey	268	2
33. Utah	172	2
34. Montana	154	1
35. Kansas	92	2
36. Wyoming	49	4
37. South Dakota	22	1
	66,967 MW	410 UNITS

[5] Most of the coal units listed in the table are retiring; 74 units representing 12,440 MW are converting to natural gas, biomass, or another fuel.

TABLE 2. All Coal Units Retiring or Converting[6]

STATE	MW CLOSING OR CONVERTING	UNITS CLOSING OR CONVERTING
1. Ohio	7,751	43
2. Pennsylvania	5,737	33
3. Alabama	5,166	26
4. Indiana	4,748	30
5. North Carolina	4,288	33
6. Illinois	4,261	18
7. Georgia	3,752	17
8. Kentucky	3,471	16
9. Virginia	2,836	21
10. West Virginia	2,737	18
11. Nevada	2,689	8
12. Tennessee	2,299	15
13. Minnesota	2,152	15
14. Utah	2,072	7
15. Iowa	1,832	32
16. South Carolina	1,759	14
17. Missouri	1,755	18
18. Arkansas	1,659	2
19. New York	1,588	13
20. Florida	1,568	7
21. Wisconsin	1,525	23
22. Massachusetts	1,517	7
23. Oklahoma	1,464	3
24. Michigan	1,433	19
25. Texas	1,399	3
26. Washington	1,376	2
27. New Mexico	1,375	5
28. Maryland	1,319	7
29. Colorado	1,172	11
30. Arizona	822	4
31. Nebraska	757	6
32. Mississippi	706	2
33. Oregon	585	1
34. Louisiana	575	1
35. Delaware	360	4
36. New Jersey	291	3
37. Connecticut	181	1
38. Montana	154	1
39. California	129	3
40. Kansas	92	2
41. Wyoming	49	4
42. South Dakota	22	1
	81,423 MW	499 UNITS

[6] Most of the coal units in the table are retiring; 93 units representing 13,890 MW are converting to natural gas, biomass, or another fuel.